Scott A. Thomson
Vice President, Regulatory Affairs and
Chief Financial Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 443-6565
Fax: (604) 443-6534
Email: scott.thomson@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

July 20, 2009

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("TGI", the "Company"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW")
Collectively the "Terasen Utilities"
Return on Equity and Capital Structure Application (the "Application")

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 1

On May 15, 2009, the Terasen Utilities filed the Application as referenced above. In accordance with Commission Order No. G-70-09 setting out the Regulatory Timetable for the Application, the Terasen Utilities respectfully submit the attached response to BCUC IR No. 1.

If there are any questions regarding the attached, please contact the undersigned.

Sincerely,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC. and
TERASEN GAS (WHISTLER) INC.

Original signed by:

Scott A. Thomson
Vice President, Regulatory Affairs & CFO

Attachments

cc (email only): Registered Parties

1.0 Reference: Exhibit B-1, Cover Letter pp. 3, 43 Use of an ROE AAM

Page 3 of the Cover Letter states that the Commission must review its formulaic approach to determining the ROE allowed in the rates of the utilities it regulates and that such a review is sought by this Application.

At page 43 of the Cover Letter, Terasen Utilities request as follows:

"Terasen requests that the Commission acknowledge changed circumstances by allowing TGI a common equity component of 40% in its capital structure effective January 1, 2010, and the Terasen Utilities request that a return on equity of 11% be established effective July 1, 2009 for TGI, and as the Benchmark ROE for the other Terasen Utilities. This level of return as the ROE for TGI and as the Benchmark ROE will apply until an application to the Commission at a future date for a change. The Terasen Utilities will pursue development of an appropriate ROE adjustment mechanism with the goal of presenting a proposal to the Commission in time to be considered in setting final rates for 2011, if possible."

1.1 Please confirm that in seeking to review the BCUC formulaic approach to determine the allowed ROE in the rates of the utilities it regulates, Terasen Utilities are applying for a variance of the existing ROE AAM as it is applied to TGI, TGVI and TGW and not the formula as applied to other investor-owned utilities regulated by the BCUC. If not, please explain precisely what Terasen Utilities are asking the Commission to review.

Response:

That is correct. The Terasen Utilities are applying to set aside the existing ROE AAM and establish a new Benchmark ROE for TGI which will also act as the reference ROE upon which the utility specific risk premium of TGVI and TGW will be added to determine each of their allowed ROE settings. The current formula fails to provide the Terasen Utilities with a fair return. Other investor owned utilities regulated by the BCUC may wish to request that their ROEs be set with reference to the new Benchmark ROE for the Terasen Utilities and if so might reasonably be expected to make their views known to the Commission through intervention in this proceeding or through separate applications. As a practical matter, the returns of BC Hydro and BCTC are both set off the allowed ROE for TGI so they would automatically see their returns adjusted based on the decision of the Commission in this Application, leaving only Pacific Northern Gas and FortisBC.

By providing the fair return requested in this Application, the BCUC can help to reduce the financial risks of the major utilities operating in the province of British Columbia and provide a solid foundation for Terasen Utilities to meet the challenges that will be faced going forward.

1.2 What is the extent of Terasen Utilities' knowledge of the processes before the NEB, AUC, OEB and Gaz Metro's application to Régie for a change in cost of capital methodology? Please provide the latest update on these processes along with an indication of when tribunal decisions may be rendered.

Response:

The generic cost of capital in proceeding before the AUC is in the argument and reply argument stage. A decision may reasonably be expected in the fourth quarter of this year.

On June 18, 2009, the OEB issued a letter in which it stated that there was not a sufficient basis to vary the 2009 cost of capital parameter values for 2009 rates for the electricity distributors in a timely manner. The letter also stated that the Board was satisfied that further examination of its policy regarding the cost of capital was warranted to ensure that, on a going forward basis, changing economic and financial conditions are accommodated if required. The Board is thus proceeding with a review of its cost of capital policy. An issues list is to be developed, interested stakeholders have been invited to file written comments and a technical conference is scheduled for the week of September 21, 2009. TGI is unable to provide an estimate of the date by which any decision might be issued by the OEB.

The NEB issued a letter on July 3, 2009 stating that it had decided to initiate a review of its RH-2-94 multi-pipeline cost of capital decision and was seeking comments on the continuing applicability of the RH-2-94 Decision. Comments are due on September 18, 2009. TGI is unable to provide an estimate of the date by which any decision might be issued by the NEB.

Gaz Metro filed its testimony on cost of capital with the Régie de l'Énergie on May 4, 2009 as part of its filing for rates to be effective October 1, 2009. Information requests from the Régie and intervenors to Gaz Metro were filed on June 11, 2009. Based on past experience, a decision is likely by early in the fourth quarter of 2009.

1.3 Please confirm that the requests for relief are a result of the "changed circumstances" perceived by Terasen Utilities and articulated in the Application. Should the "changed circumstances" return to circumstances of prior years or if long term bond yields move to an upward trend, is it the understanding of Terasen that the current ROE AAM would continue to apply?

Response:

The "changed circumstances" articulated in the Application relate both to changes in risk and to recent events in the financial and credit markets that increased the awareness, and provided more evidence, that the current AAM does not produce results that are appropriate. This information request relates to the latter change in circumstances, which are discussed further below.

The recent financial and credit market crisis has only made it more apparent what has been a problem for Canadian regulated utilities for a long time, i.e. that the returns established by the current British Columbia ROE AAM and those that produce similar results, such as the NEB formula, fail to meet the Fair Return Standard. The direct answer to the question posed in the second sentence of this information request is "no".

As noted in the Application, the Terasen Utilities seek to establish a new Benchmark ROE based on the evidence filed in this proceeding. If a new formula can be developed to make subsequent adjustments to allowed returns in the future that continues to ensure the Fair Return Standard can be met, then the Terasen Utilities would be supportive of its introduction and have indicated they will work towards that goal.

It is time to establish an appropriate and fair return. The mechanics of a robust formula that can operate successfully in all market conditions is a matter for a future regulatory proceeding and will be in part dependent on the outcome of this proceeding.

2.0 Reference: Exhibit B-1, Cover Letter pp. 3, 4 Reasons for a Review

The Commission's decision respecting Terasen's last Application issued on March 2, 2006 stated that 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. One of the reasons Terasen Utilities filed the Application on May 15, 2009 is based on the forecast 30 year GCB yields on which the annual benchmark ROE is set.

2.1 Does TGI still consider itself a "benchmark low-risk utility" for the purposes of setting allowed ROEs?

Response:

TGI has been designated "a benchmark low-risk utility" by the Commission. In reference to ROE of the benchmark low risk utility in the March 2006 Decision (line two of the question) is a reference to allowed ROE for TGI.

By Regulation the crown owned utilities (BC Hydro and BC Transmission Corporation) have their ROE set with reference to the most comparable investor owned utility, which by virtue of size and geography has defaulted to TGI. TGI accepts that it is has been, and will be, the benchmark utility in respect of being the "benchmark" or "standard" used to set the ROE of other utilities in B.C., but does not consider itself to be "a benchmark low-risk utility" now, if it ever was.

Any utility could act as the benchmark and TGI due to its size has been selected as the benchmark by the BCUC in the past. Clearly BC Hydro is a lower risk utility than TGI by virtue of its government ownership, cost structure and regulation.

2.2 Terasen utilities have put forward testimony from Mr. Carmichael, opinion of Ms. McShane, and evidence of Dr. Vander Weide. Is it the intention of Terasen Utilities to include all three experts for cross-examination?

Response:

Yes.

2.3 Please comment on the time allocated to each of the three witnesses to compile evidence for this Application and the estimated total expenses on this Application.

Response:

Mr. Carmichael was asked to provide an overview of financial markets and conditions and to analyze and provide comment on the appropriateness of the current formula based determination of a fair rate of return on equity for Terasen. Ms. McShane and Dr. Vander Weide were each engaged to provide evidence and form an opinion of a fair return for TGI based on a number of different approaches in order to ensure a comprehensive evidentiary record for the Commission.

Each of the witnesses prepared their testimony between January and May of this year and will be involved in preparing responses to Information Requests on their evidence, preparation for and attendance at the oral hearing to sit for cross-examination, and final submissions.

In addition to the three expert witnesses there will be external legal support and witness preparation and training costs. Based on actual time incurred for preparation of evidence and the first round of information requests plus estimates for a second round of information requests which are assumed to be limited given the body of evidence filed and the scope of the original round of IRs, and time for the review of intervenor evidence preparation of IRs thereon, the estimated total third party expenses for this Application (excluding any costs for participant funding and excluding any costs assessed by the BCUC for hearing room time, etc.) are on the order of $675,000.

Final costs will be dependent on the length of the hearing, the extent of subsequent information requests and the intervenor evidence.

3.0 Reference: General

3.1 Please provide information in tabular format on Terasen Gas Inc. for each year since 1999: the number of customers, net incremental customers, customer growth percentage, annual throughput and peak day throughput (GJ), throughput change percentage, rate base, and revenues with and without cost of gas.

Response:

The following table illustrates the annual net customer additions, year-ending customers, customer growth rate, annual normalized throughput, annual normalized throughput growth rate, peak day demand, peak day demand growth, peak day sendout, peak day sendout growth rate, normalized actual revenues (both with and without the cost of gas), and also the normalized actual rate base.

The peak day demand figures represent the peak day demand that is filed in the current and also historical Annual Contracting Plans, whereas the peak day sendout figures represent the maximum daily sendout that was experienced in each calendar year.

	1999	2000	2001	2002	2003
Net Customer Additions	11,768	5,686	4,835	7,360	6,306
Year-End Customers	751,893	758,437	763,302	769,908	775,454
Customer Growth (%)		0.9%	0.6%	0.9%	0.7%
Total Normalized Throughput[1] (PJ)	238	244	246	220	219
Normalized Throughput Growth (%)		2.6%	1.1%	-10.6%	-0.6%
Peak Day Demand[2] (TJ/Day)	1,291	1,305	1,305	1,245	1,256
Peak Day Demand Growth (%)		1.1%	0.0%	-4.6%	0.9%
Peak Day Sendout[2] (TJ/Day)	730	865	718	799	718
Peak Day Sendout Growth (%)		18.4%	-16.9%	11.3%	-10.2%
Normalized Actual Revenue (with Cost of Gas) ($000's)[2]	843,995	1,086,236	1,387,274	1,192,774	1,317,184
Normalized Actual Revenue (without Cost of Gas) ($000's)[2]	389,417	409,142	457,930	465,605	470,685
Normalized Actual Rate Base ($000's)[2]	1,614,579	1,686,433	2,209,380	2,213,460	2,248,843

	2004	2005	2006	2007	2008
Net Customer Additions	10,716	11,427	9,595	9,277	7,959
Year-End Customers	786,958	799,378	812,683[3]	822,598	831,845
Customer Growth (%)	1.5%	1.6%	1.3%[4]	1.2%	1.1%
Total Normalized Throughput[1] (PJ)	220	213	209	215	209
Normalized Throughput Growth (%)	0.5%	-3.3%	-1.7%	2.8%	-2.5%
Peak Day Demand[2] (TJ/Day)	1,256	1,256	1,278	1,275	1,279
Peak Day Demand Growth (%)	0.0%	0.0%	1.8%	-0.2%	0.3%
Peak Day Sendout[2] (TJ/Day)	1,038	950	945	879	1,013
Peak Day Sendout Growth (%)	44.5%	-8.5%	-0.5%	-7.0%	15.3%
Normalized Actual Revenue (with Cost of Gas) ($000's)[2]	1,342,345	1,433,340	1,524,464	1,524,464	1,491,626
Normalized Actual Revenue (without Cost of Gas) ($000's)[2]	474,666	480,697	495,020	495,020	493,908
Normalized Actual Rate Base ($000's)[2]	2,305,591	2,408,116	2,442,352	2,426,180	2,474,447

Notes:

1. Includes all customer classes - residential, commercial, firm sales & industrial, also includes TGVI volumes
2. Includes Squamish as part of TGI from 2007 onwards
3. Includes 3,124 additional customers due to Squamish amalgamation
4. Growth rate calculation excludes the Squamish amalgamation

3.2 Please provide the detailed long-term debt continuity schedule for TGI, updated for the recent issuances.

Response:

The following shows the long-term debt continuity schedule of TGI from 2004 to 2009 projected.

Tearsen Gas Inc.
Long Term Debt Continuity
For the Years Ended December 31
($000's)

	2004	2005	2006	2007	2008	2009 Projected
Total Opening Long Term Debt (Financial Statements)	$ 1,768.6	$ 1,909.1	$ 1,501.6	$ 1,500.1	$ 1,490.7	$ 1,551.7
Redemptions	-	(395.0)	(120.0)	(250.0)	(188.0)	(59.9)
Notes Payable	(8.6)	(310.5)	-	-	-	-
Other Debt Issues & Capital Leases	(0.9)	(2.0)	(1.6)	(9.4)	(0.9)	(1.4)
New Debt Issues	150.0	300.0	120.0	250.0	250.0	100.0
Total Year End Long Term Debt (Financial Statements)	1,909.1	1,501.6	1,500.1	1,490.7	1,551.7	1,590.4
Less:						
Inland Energy Corporation Debentures	(150.0)	(150.0)	(150.0)	(150.0)	(150.0)	(150.0)
Non-Utility Portion of Debt Issues						
Series A	(16.0)	(16.0)	(16.0)	(16.0)	(16.0)	(16.0)
Series B	(42.7)	(42.7)	(42.7)	(42.7)	(42.7)	(42.7)
Southern Crossing Trust	(310.5)	-	-	-	-	-
Long Term Debt Issue Costs				10.8	12.8	14.4
Capital Leases	(10.8)	(8.8)	(7.2)	(8.6)	(9.7)	(9.9)
	(530.0)	(217.5)	(215.9)	(206.5)	(205.6)	(204.2)
Add:						
LILO Obligation	58.8	92.5	90.9	88.0	85.2	82.3
Coastal Facilities		50.3	50.3	50.3	-	-
Less:						
Fort Nelson	(2.6)	(2.6)	(2.6)	(2.6)	(2.9)	(3.0)
Total Year End Long Term Debt (BCUC Annual Report)	1,435.3	1,424.3	1,422.7	1,419.8	1,428.4	1,465.5
Adjustment to Average Long Term Debt	(119.9)	20.4	10.3	50.2	(54.5)	10.9
Total Average Long Term Debt Included in Rate Base	$ 1,315.4	$ 1,444.7	$ 1,432.9	$ 1,470.1	$ 1,373.8	$ 1,476.5

The following shows the details of the long-term debt outstanding in each year from 2004 to 2009 projected.

Amounts in $ 000s	Rate	Maturity	For the year-ended 2004	2005	2006	2007	2008	Projected 2009
Purchase Money Mortgages								
Series A	11.80%	September 30, 2015	58.9	58.9	58.9	58.9	58.9	58.9
Series B	10.30%	September 30, 2016	157.3	157.3	157.3	157.3	157.3	157.3
Debentures & Medium Term Note Debentures								
Series D	9.75%	December 17, 2006	20.0	20.0	19.2	-	-	-
Series E	10.75%	June 7, 2009	59.9	59.9	59.9	59.9	59.9	25.8
2004 Long Term Debt Issue	6.25%	September 30, 2014	37.8	-	-	-	-	-
Coastal Facilities	6.10%	January 1, 2008	-	50.3	50.3	50.3	-	-
Series 6	9.80%	February 9, 2005	40.0	4.4	-	-	-	-
Series 7	10.75%	June 29, 2005	5.0	2.5	-	-	-	-
Series 9	6.20%	June 2, 2008	188.0	188.0	188.0	188.0	78.6	-
Series 11	6.95%	September 21, 2029	150.0	150.0	150.0	150.0	150.0	150.0
Series 12	6.50%	July 20, 2005	200.0	110.1	-	-	-	-
Series 13	6.50%	October 16, 2007	100.0	100.0	100.0	78.9	-	-
Series 16	6.15%	July 31, 2006	100.0	100.0	57.8	-	-	-
Series 17	3.60%	September 26, 2005	150.0	110.5	-	-	-	-
Series 17	4.35%	September 28, 2007	-	39.0	-	-	-	-
Series 18	6.50%	May 1, 2034	-	150.0	150.0	150.0	150.0	150.0
Series 19	5.90%	September 30, 2015	-	55.5	150.0	150.0	150.0	150.0
Series 20	4.13%	October 24, 2007	-	-	150.0	124.5	-	-
Series 21	5.55%	September 25, 2036	-	-	50.7	120.0	120.0	120.0
Series 22	6.00%	October 2, 2037	-	-	-	97.0	250.0	250.0
Series 23	5.80%	June 1, 2038	-	-	-	-	116.9	250.0
Series 24	6.55%	February 24, 2039	-	-	-	-	-	85.2
LILO Obligation								
Kelowna			30.0	30.8	31.7	29.8	28.7	27.7
Nelson			5.0	5.2	5.0	4.7	4.6	4.4
Vernon			16.0	15.5	15.0	14.1	13.7	13.2
Prince George				39.4	38.3	36.0	34.9	33.8
Creston				-	3.6	3.4	3.3	3.2
Fort Nelson Allocation			- 2.5	- 2.6	- 2.7	- 2.8	- 2.9	- 3.0
Total average long-term debt included in rate base			**$ 1,315.4**	**$ 1,444.7**	**$ 1,432.9**	**$ 1,470.1**	**$ 1,373.8**	**$1,476.5**

3.3 Please provide a summary of TGI's allowed ROE and actual ROE for each year since rate regulation for BC Gas commenced. Also, for each year when a PBR mechanism was in effect, please include a record of all incentives earned, and the impact of these incentives in terms of the percentage of actual ROE earned.

Response:

Please refer to the table which follows for a summary of TGI's allowed ROE and actual ROE from 1992 to 2008, inclusive of the record of incentives earned and the impact of these incentives on the percentage of actual ROE earned.

3.4 Please provide the dollar impact and delivery rate change for the proposed increase in equity thickness from 35.01 percent to 40 percent and ROE from 8.47 percent to 11.00 percent for TGI.

Response:

The dollar impact of the proposed increase in equity thickness from 35.01 percent to 40 percent and ROE from 8.47 percent to 11.00 percent is approximately $44.9 million of revenue requirement for TGI. This translates to an approximate delivery rate impact of 8.5% and results in an approximate increase to the annual bill of a TGI lower mainland Residential customer of $38 per year or approximately 3.6%.

3.5 Please provide the dollar impact to TGI of an absolute 1% increase in the equity thickness of the company.

Response:

The dollar impact of an absolute 1% increase in equity thickness is an increase of approximately $2.4 million in the revenue requirement for TGI.

3.6 Please provide the dollar impact to TGI and TGVI of a 25 basis points increase to the ROE of each company.

Response:

The dollar impact of a 25 basis points increase to the ROE is an approximate increase of $3.1 million to the revenue requirement of TGI and an approximate increase of $0.8 million to the revenue requirement of TGVI. The revenue requirement increase for TGVI may not necessarily translate to a customer rate impact because of the soft cap mechanism.

4.0 Reference: Exhibit B-1, Cover Letter, p. 2 TGVI Special Direction

4.1 Please confirm which Special Direction is being referenced. Please provide a copy of the provisions of the Special Direction.

Response:

On page 2 of the Cover Letter, the Special Direction being referred to is Order-in-Council No. 1510 Vancouver Island Natural Gas Pipeline Special Direction, dated December 13, 1995. The Special Direction is included as Attachment 4.1.

5.0 Reference: Exhibit B-1, Cover Letter p. 5 NEB Decision on TQM

Page 5 of the Cover Letter states that in the RH-1-2008 Decision, the NEB discarded the ROE determination from the RH-2-94 formula, and effectively increased the allowed ROE for TQM, at the previously approved capital structure, by almost 300 basis points over what the RH-2-94 formula produced for 2007 and 2008.

5.1 Please file a copy of the NEB Decision on TQM RH-1-2008.

Response:

The NEB Decision on TQM RH-1-2008 is provided in Attachment 5.1.

5.2 Please confirm that the 2009 Return on Common Equity for certain Group 1 pipeline companies at 8.57 percent based on the Multi-Pipeline Cost of Capital Decision RH-2-94 is still in effect.

Response:

Confirmed. The NEB, as indicated in response to BCUC No. 1.2.1, has released a decision, a copy of which is included in Attachment 5.2, stating that it intends to initiate a review of the formula later this year.

5.2.1 Please also provide the allowed ROEs and equity ratios for the years 2007 and 2008 for those pipeline companies regulated by the NEB.

Response:

The multi-pipeline formula ROEs for 2007 and 2008 were 8.46% and 8.71% respectively. The multi-pipeline formula ROE was adopted as part of settlements which covered 2007 and 2008 for TransCanada (equity ratio of 40%), TCPL-BC System (equity ratio of 36%), Foothills (equity ratio of 36%), and Westcoast Mainline (equity ratio of 36%). The 2007 and 2008 allowed ROEs and capital structures for Group 1 Gas Pipelines regulated by the NEB but not governed by the formula (also the result of settlements) are Alliance Pipeline (ROE of 11.3% on 30% equity for both years) and Maritimes and Northeast Pipeline (ROEs of 12% and 11.66% for 2007 and 2008 on equity ratios of 29.3% and 31.18% respectively).

5.3 Page 29 of the NEB Decision says that the Board has decided to rely on a market-based ATWACC methodology to interpret the information that can be extracted from different samples comparable to TQM and from the financial market as a whole.

5.3.1 Please provide a calculation of the market based ATWACC that would apply to TGI based on the methodology employed by the NEB and considering market circumstances as at April 1, 2009 and July 1, 2009. Show calculations and explain the differences in the results.

Response:

The specifics of the methodology which the NEB utilized to arrive at the 6.4% ATWACC allowed for 2007 and 2008 are not detailed enough to be able to replicate their approach using more recent data. For example, it is not clear what weight the NEB gave to the various proxy samples of companies (and thus what or whose market value capital structure is implied by the 6.4% ATWACC). Nor is it possible to discern what values were used for betas and market risk premiums. Further, it is not possible to infer what changes the NEB might have made in the relevant CAPM inputs if the analysis had been done in 2009, particularly in light of the interceding events in the capital markets.

Section VI, G of Ms. McShane's testimony developed market-based ATWACCs for proxy samples using multiple market-based methodologies for the cost of equity. The average ATWACC was 7.4%. She then translated the average ATWACC into a ROE for TGI at the requested book value common equity ratio of 40% and a current debt cost of 6.625%. The indicated ROE at 40% equity was approximately 11.0%. The ATWACC and resulting ROE at 40% equity would not be materially different had the cost of equity tests been applied on April 1, 2009. Time constraints do not permit the cost of equity tests to be updated for the most recent data available.

5.3.2 What ROE would be implied assuming TGI's current deemed capital structure of 35.01 percent equity and current embedded cost of debt?

Response:

The NEB, in its application of the ATWACC methodology, relied on the premise that the cost of capital is flat across all capital structures. While this is unlikely to be the case from 0% debt to 100% debt, that conclusion is not unreasonable across the range of capital structures relied on for the purpose of the calculation requested. Under this assumption, using TGI's embedded cost of debt of 6.64% and a book value common equity ratio of 35.01%, Ms. McShane's ATWACC of 7.4% translates into an ROE of 12.3%.

5.4 Please provide a comparison of the Business Risks of TGI and TQM. Does TGI agree with the views of some witnesses in the TQM proceeding that LDCs are generally of lower risk than pipelines? Please explain your answer.

Response:

As TGI has not done an in-depth independent analysis of the business risks of TQM, it was guided by the NEB's conclusions in this regard. TGI notes that the NEB considered business risks in the following categories: (1) Supply; (2) Market; (3) Competitive; (4) Operating; and (5) Regulatory. With respect to regulatory risks, under the current regulatory framework, TQM's forecast revenue requirement is rolled into the TCPL Mainline revenue requirement by contract and it receives 99% of its approved revenue requirement in 12 monthly payments from TCPL. The NEB noted that year-to-year earnings fluctuations are low, and that its past deferral account coverage was similar to its current deferral account coverage. It was not convinced that TQM's business risks had increased due to the NEB's regulatory policy toward more competition between pipelines. In comparison, TGI's revenues are, under the current regulatory framework, subject to greater fluctuation than TQM's. With respect to the longer-term, TGI has no basis to conclude that there is a significant difference in the likelihood that the NEB or the BCUC regulatory frameworks will change, altering the ability of the companies to recover their invested capital over the longer term.

The NEB concluded that TQM's market risk (which it defined as the business risk that arises from the overall size of the market and the ability of the pipeline to capture market share) had increased since RH-2-94. The NEB defined competitive risk as the risk resulting from competition for customers at both the supply and market ends of the pipeline system. The NEB included in competitive risk the competition in Québec markets against alternative energy sources and the ability of TQM to capture markets in New England. The NEB concluded that both competitive risk and market risk had increased due to the high industrial load and the declining competitive position of natural gas in Québec, competitive alternatives for delivering natural gas into the Northeast U.S. and higher supply risk. As TGI documents in its Application, its market and competitive risks have also increased significantly over the time horizon at issue in the TQM decision.

As regards supply risk, the NEB defined supply risk as the physical availability of competitively priced natural gas volumes that could affect TQM's income-earning capability. The Board concluded that TQM's supply risk had increased since RH-2-94 due to declining conventional supplies from the Western Canadian Sedimentary Basin, the dependence in part on economic unconventional supplies (whose development is uncertain) to maintain flows on the TCPL Mainline, and the higher absolute prices of natural gas. As defined by the NEB, TGI's supply risks have also increased, since, as indicated in response to BCUC No. 1, 40.1, conventional supplies of natural gas are declining and its competitiveness in the longer-term will be dependent on its ability to economically source unconventional supplies to serve its customers.

Operating risk is defined as the risk to the income-earning capability that arises from technical and operational factors. There was little evidence on the operating risk in the TQM decision and the Board concluded that there was insufficient evidence to conclude that the operating risk had changed. TGI does not view that the differences in operating risk as between TQM and TGI are material.

On balance, taking account of both short-term and long-term risks, TGI does views its business risks as being no lower than those of TQM given TGI's market and competitive risks. TGI has not analyzed gas pipelines versus LDCs in the broad sense that is implied in the question, but based on its assessment of TQM versus TGI, would disagree with a conclusion that TQM faces higher business risks than either TGI or the typical Canadian gas LDC.

5.5 Does TGI believe the market based ATWACC methodology employed by the NEB is an appropriate regulatory methodology for TGI? Would TGI be prepared to assume the risks inherent in using a market based cost of debt and a market based capital structure?

Response:

First, TGI would like to confirm that it is not proposing that the BCUC adopt an ATWACC methodology. Its discussion of the NEB decision and its results in the Application were intended to highlight the significant differential between the effective ROEs that were adopted for TQM for 2007 and 2008 and the corresponding NEB multi-pipeline ROEs for the same years. TGI has not fully analyzed the ATWACC methodology as applied by the NEB to determine whether it would be appropriate for the Company. Nevertheless, if the BCUC were to determine that an

ATWACC methodology were appropriate, TGI does not believe that it should be at risk for the difference between the embedded cost of debt that it has incurred under the existing methodology for setting cost of capital and the current cost of debt.

TGI understands that under the ATWACC approach, an ROE at a market-weighted capital structure converts to an ROE at a book value weighted capital structure. As such, TGI believes it could be appropriate to utilize a market based capital structure/ROE in order to establish an allowed ROE on the deemed equity component for rate base/rate making purposes, using embedded debt costs to avoid windfall gains or losses to customers or ratepayers. However, as noted, TGI has not investigated this approach in depth.

5.6 On page 81 of the TQM Decision the NEB states:

"The difference between market cost of debt and embedded cost of debt in this case is small and therefore does not require consideration of a grandfathering or transition phase for TQM for 2007 and 2008."

5.6.1 Does TGI view the market based ATWACC to be a modification or violation of the regulatory principle of cost based rates? Please consider each of the debt cost, equity cost and capital structure.

Response:

The principle of cost based rates itself does not specify how those costs are to be measured. In an original cost jurisdiction, such as British Columbia, all of the capital related costs included in the revenue requirement, with the exception of the cost of equity, are, in principle, historic average costs. The market-derived cost of equity, in contrast, is a marginal cost concept. If the cost of equity is estimated using market-derived tests only (i.e. CAPM and DCF), which are by definition estimated by reference to market values, the market value capital structures represent the financial risk component of that cost. TGI does not believe that it is a violation of cost based rates to recognize that the financial risk inherent in the book value capital structure to which the ROE is applied may be higher or lower than the financial risk inherent in the market value capital structures of the comparable companies used to estimate the cost of equity. The higher or lower financial risk of the book value capital structure relative to the market value capital structures of the proxies used to estimate the cost of equity would require an adjustment to that cost. The recognition of this relationship in the allowed ROE is fully consistent with a marginal cost approach to estimating the cost of equity and does not require a departure from using an original cost rate base, a book value capital structure or the recovery of the embedded cost of debt.

5.6.2 What would TGI do if its embedded cost of debt significantly exceeded the market cost of debt? Please show the impact that an embedded cost of debt 3 percent higher than the market cost of debt would have on ROE at the current 35 per cent equity in the capital structure.

Response:

As noted in response to BCUC 1.5.5, TGI is not requesting an ATWACC approach. Further, as noted in that response, even if the BCUC were to adopt an ATWACC approach, TGI does not believe that it should be at risk for the difference between the embedded cost of debt that it has incurred under the existing methodology and the current cost of debt. If ATWACC were adopted and TGI were allowed to recover its embedded cost of debt, the ATWACC estimate of 7.4% used in response to BCUC 5.3.1 would need to be adjusted for the difference between the embedded debt cost (9.625%) and the current debt cost (6.625% in Ms. McShane's ATWACC estimates). The ROE at 35.01% would be 12.3%, identical to the ROE that would result if the current and embedded debt cost were both 6.625%.

The alternative would be to recalculate the ATWACC using the market value capital structures of the proxy samples (47%/53% debt/equity) in conjunction with the embedded cost of debt (9.625% for the purpose of this question) and the market cost of equity (9.75%). In this case, the ATWACC would increase from 7.4% estimated in response to BCUC 5.3.1 to 8.4% and the ROE at 35.01% would be 11.2%.

6.0 Reference: Exhibit B-1, Cover Letter, p. 7 Worsening Market Conditions

6.1 The Application states that: "No pipelines are being built under formula based allowed returns in Canada." Is this statement true in light of the recently completed Terasen Whistler pipeline? Is it not true that TGVI operate under a formula based allowed return on equity?

Response:

It is true that TGVI's ROE is established with reference to the BCUC's ROE AAM. The statement refers to large scale oil and gas transmission pipelines, primarily those regulated by the NEB. For example, the Alliance Pipeline and Maritimes & Northeast are the most recent major greenfield natural gas transmission pipelines that have been constructed. In both cases, the projects were justified and approved based on negotiated rates between the pipeline company and the shippers that allowed for higher ROE's than would have resulted from the NEB ROE formula. The Whistler pipeline is an approximately 50km 8" intermediate pressure pipeline extension of TGVI's existing transmission system. It is a relatively small addition to the existing system rather than what would be considered a major new pipeline investment.

7.0 Reference: Exhibit B-1, Cover Letter, p. 7 Credit Spreads and Calculation Basis

Terasen Utilities state that the unusually wide and volatile credit spreads (i.e., yields on corporate bonds in excess of the GCB yield) observed in the market during the few months prior to the Application date support the need to reconsider use of the ROE AAM formula, including abandoning the formula.

7.1 Is it the case that the current ROE AAM implicitly assumes a stable credit spread between the GCB yield (which is taken as having essentially zero credit risk) and the yield on corporate bonds of TGI's higher credit risk level?

Response:

The current AAM assumes a stable equity risk premium between the GCB yield and the allowed ROE. By extension, assuming a stable equity risk premium would imply that the corporate credit spread is stable.

7.2 Has the credit spread defined in the preceding paragraph in fact been stable over the past year, or was this spread abnormally wide during the period of time commonly referred to as the credit crisis, when GCB yields fell – due to a flight to quality – while yields on higher risk bonds actually rose as the perceived risks of liquidity and potential default increased?

Response:

Credit spreads have been relatively unstable for over two years. Commencing in 2007, corporate credit spreads started to increase, as well as become more volatile, in part due to the concerns around asset back commercial paper and sub-prime mortgages. Spreads continued to widen through the early part of 2008, with the failure of Bear Sterns and other financial institutions. Commencing in September 2008 with the failure of AIG, Lehman Brothers, Merrill Lynch and others, events which were catalysts for what was commonly referred to as the credit crisis, corporate spreads increased dramatically. This increase in spreads has continued into 2009.

7.3 Has this credit spread been falling back toward historical norms over the past six months (i.e., January to June 2009)?

Response:

Over the past six months, corporate credit spreads have narrowed from those witnessed from November 2008 to January 2009. However, current corporate spreads remain higher than those observed in recent years.

7.3.1 What is the outlook for credit spreads for the second half of 2009 and into 2010?

Response:

The Companies expect corporate credit spreads will remain at elevated levels with higher average volatility over the next number of months. The expectation is based in part on continued concerns over a prolonged economic recession, as well common market perceptions that the global financial system and flow of capital will be less robust or as free as in periods past. This stems from several factors, including tighter monitoring, control and oversight of lending practices. Furthermore, it is unknown whether corporate spreads will narrow to levels experienced in years preceding the onset of the credit crisis given investors may now place greater emphasis on liquidity and default risks than ever before.

7.4 Rather than abandon the AAM formula, would it be appropriate to instead make a special temporary adjustment or over-ride to the ROE formula rate to account for an unusual credit-crisis spread-widening that existed during the past several months but which is now fading away?

Response:

No. A temporary over-ride to address the widening of the credit spreads assumes that during normal times the AAM formulated a Return on Equity that satisfied the Fair Return Standard. The Terasen Utilities has indicated this is not the case and a temporary adjustment to the AAM formula does not address the overall need to meet the Fair Return Standard. Terasen Utilities seek to establish a new Benchmark ROE to ensure the Fair Return Standard is met.

7.5 Are there features or attributes of bonds issued by the federal government, such as flight to quality factors associated with their essentially zero credit risk, that render GCBs a sometimes problematic base against which to compare corporate bond yields of TGI's risk class?

Response:

Yes. Reliance on GCB yields are problematic as a base against which to compare corporate bond yields' reliance on GCB yields in the AAM it is also problematic in the calculation of an ROE that meets the Fair Return Standard. The reason stems from the fact that risks of the federal government and a corporate utility such as Terasen are perceived differently by investors, and that factors that change the GCB Yield will not necessarily reflect the changes in the equity return of a corporate utility. In economic recessions, for example, market participants will shift into GCBs driving down yields (commonly referred to as a flight to quality). Conversely, corporate debt is perceived by investors to be more risky as evidenced by them demanding a premium in the form of wider corporate spreads. Higher risk premiums on debt translate into even higher perceived risk to holders of common equity. To receive a Fair Return, Common Equity holders will require the Terasen Utilities produce a higher ROE for the same level of risk; however, this is completely contrary to the AAM, which will produce a lower ROE during this time.

Terasen Utilities supports the following statement by the NEB in its TQM Decision page 17, paragraph 2:

> *"The RH-2-94 Formula relies on a single variable, which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yield, and hence, may not be accounted for by the results of the RH-2-94 Formula."*

7.6 Would it be appropriate to use some measure of corporate bond yields, rather than the GCB yield, as the base of an ROE formula in an attempt to find a credit spread between the base yield (i.e., some index of corporate bond yields) and the yield on corporate bonds of TGI's credit risk level that is more stable over time and thus captures potential issues related to the volatility of the credit spread between government and corporate bond yields?

Response:

The Terasen Utilities in this Application believe that the current benchmark ROE is inadequate, and the AAM that sets the benchmark ROE is flawed. Any discussion on a new ROE formula mechanism is premature until the Benchmark ROE is re-established at an appropriate level. To the extent the starting point ROE is not set at an appropriate level, an improved formula that more correctly tracks changes in ROE would still not deliver an adequate return if the starting point is incorrect.

With regard to alternative formulas, the Company considered a formula that adjusted the ROE based on the year over year changes in long term corporate utility bonds of a similar credit risk to TGI. In the context of the Canadian capital markets, as noted in page 32 of the Application, it is not apparent to TGI that such a corporate bond utility index actually exists. A proxy may involve some form of general corporate bond index, however, to the extent there are faulty assumptions as to the relationship between the utility ROE and the general corporate bond index, the formula over time may lead to inadequate results similar to the existing AAM.

As stated in its Application, TGI will continue to work towards developing an alternative formula. In the interim, TGI considers its proposal to maintain the benchmark ROE as established in this proceeding to be preferable to the establishment of an alternative formula which may turn out to be unworkable either due to incorrect assumptions regarding the relationship between the ROE and the adjustment variable(s) or due to lack of publicly available data for implementation.

8.0 Reference: Exhibit B-1, Cover Letter p. 13 Effective Returns Comparisons

8.1 Please add three columns to the table on page 13 to show the credit agencies Moody's, S&P and DBRS most recent ratings of the utilities listed in Canada.

Response:

The following includes the long-term debt ratings for the Canadian utilities and pipeline companies disclosed on page 13 of the Application:

	Credit Rating Agency		
	Moody's	**S&P**	**DBRS**
Newfoundland Power	Baa1	NR	A
Maritime Electric	NR	A	NR
TGVI	A3	NR	BBB(High)
FortisBC	Baa2	NR	BBB(High)
Gaz Metro	NR	A	A
TCPL	A3	A-	A
Atco Gas	NR	NR	NR
FortisAlberta	Baa1	A-	A(low)
Westcoast Energy	NR	BBB+	A(low)
Union Gas	NR	BBB+	A
Enbridge Gas	NR	A-	A
TGI	A3	A	A

9.0 Reference: Exhibit B-1, Cover Letter p. 13 Higher Leverage

"This higher leverage (more debt, less equity) makes TGI even less attractive to equity investors. Because higher leverage increases financial risk, it can impact the company's credit ratings, degrade financial ratios and debt covenant tests and impact its ability to attract capital on reasonable terms and in sufficient quantities under all market conditions."

9.1 Please provide information, including rates and amounts, on the last three TGI equity issues.

Response:

Terasen Gas does not issue public equity but rather obtained its equity from its shareholder, Terasen Inc. The following is a listing of the past three equity issuances at Terasen Gas Inc.

Year	Gross Proceeds	Number of Shares
2000	$ 120,000,000.00	11,179,390
1998	$ 64,890,000.00	3,000,000
1995	$ 25,061,234.69	2,231,633

9.2 Please provide information, including rates and amounts, on the last three Fortis Inc. equity issues.

Response:

The requested information is provided in the following table.

Preference share dividend rate	Date of Issue	# of shares	Price per share	Gross proceeds
N/A	Dec-08	11,700,000	$ 25.65	$ 300,105,000
5.25%	May-08	8,000,000	$ 25.00	$ 200,000,000
N/A	May-07	44,275,000	$ 26.00	$ 1,151,150,000

10.0 Reference: Exhibit B-1, Cover Letter pp. 16, 17 & Appendix 3, p.35

External Reports on Disparity Between US and Canadian ROEs

Terasen Utilities describe some of the conclusions of studies, namely: Concentric and NERA, undertaken to examine the disparity between Canadian and U.S. ROEs and the underlying business and operating risks differences.

At page 35 on the Concentric Report, a group of eight US gas companies is listed as "comparable companies."

10.1 To the best of TGI's knowledge, how many of these eight gas companies in the US are carrying out one or more of the following social policy instruments: (i) active payment assistance programs for low income customers, (ii) senior citizens discount programs, (iii) arrangements for customers to programs administered by local and federal governments, (iv) incorporate special tariff for low income customers, (v) regulations regarding disconnection in cold weather and to military personnel and forgiveness of non-payment (vi) special assistance for social service agencies, schools or religious institutions; (vii) utility's partnership with The Salvation Army, with employees and own corporate giving programs.

Response:

More than 12.5% of Americans live in extreme poverty, according to the US Census Bureau News[1]. As utility customers, they are faced with financial difficulties in paying their monthly energy bills, and this presents a challenge for utilities to collect revenue. That is why approximately 80% of US utilities offer low-income customers assistance in some form.[2]

Many of the eight utilities reviewed below, assist in the coordination of the Low Income Home Energy Assistance Program referred to as LIHEAP. This program is offered by the US Department of Health and Human Services; directing assistance payments to utility companies on behalf of individuals that are having difficulty in paying their utility bills. The US Department of Energy also offers assistance in weatherizing homes.

Most of the eight utilities also participate in the Energy Share Program; an emergency fund established through customer donations that provides direct assistance to qualified people facing unexpected financial difficulties, such as the loss of a job or a medical emergency. Energy Share donations are completely managed and distributed by The Salvation Army. In addition, utilities generally offer a deferred payment plan that allows customers to pay their bill over an extended period if they can demonstrate a hardship and have outstanding bills.

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[1] US Census Bureau News
[2] *Chartwell Report on Low-Income Assistance Programs, December 2003, page 6.*

Figure 1: Income assistance programs by utility

	Southwest Gas Corporation (Arizona)	Atlanta Gas Light Company	Northern Illinois Gas Company	Michigan Consolidated Gas Company	CenterPoint Energy Resources (Minnesota)	Public Service Electric Gas (New Jersey)	Puget Sound Energy, Inc. (Washington)	Wisconsin Gas LLC
Active payment assistance for low income customers				●	●		●	●
Senior citizens discount programs		●		●		●		
Arrangements for customers to programs administered by local and federal governments	●	●	●	●	●	●	●	●
Incorporate special tariff for low income customers	●							
Regulations regarding disconnection in cold weather	●	●	●	●	●	●	●	●
Regulations regarding disconnection of military personnel and forgiveness of non-payment			●					●
Special assistance for social service agencies, schools or religious institutions						●	●	●
Partnership with the Salvation Army	●	●	●	●	●		●	
Partnership with employees			●			●	●	
Utility corporate giving program						●	●	

Southwest Gas Corporation

Southwest serves three states, including Arizona, California and Nevada. Each state has separate rules and regulations regarding income assistance programs.

In Arizona, Southwest's primary assistance programs include the Low Income Ratepayer Assistance Program. This program provides a 20% discount on the first 150 therms used each month during November through April. The number of household members, as well as the total household gross annual income determines program eligibility. Ratepayers eligible for assistance are charged on a special tariff. Southwest Gas Corporation in cooperation with the Arizona Energy Office offer the *LIEC (Low Income Energy Conservation) Program*. This program offers free energy audits, education in conservation and weatherization materials, which will increase energy efficiency and safety in low-income homes.

Arizona Utilities are advised not to terminate residential service when the customer has an inability to pay and where weather will be especially dangerous to health (usually 32° F or below for winter and triple digits for summer) as determined by the Commission. There are also rules prohibiting disconnection of service for certain medical reasons.

In California, Southwest offers several different programs for customers in financial difficulty. The Alternate Rates for Energy (CARE) Program provides a discount on monthly gas bills to income-qualified customers at their primary residence. CARE eligibility is determined by the total gross household income and number of people living in the residence. The program is funded through a rate surcharge paid by all other utility customers.

The California Additional Baseline Program is only available to California customers of Southwest Gas Corporation who are full-time residents of the household. Upon completion of an application and verification by a licensed physician, surgeon, or osteopath, an additional monthly medical allowance of 25 therms will be provided for hemiplegic / paraplegic / quadriplegic persons, multiple sclerosis / scleroderma patients and persons who are being treated for a life threatening illness and have a compromised immune system.

California utilities are prohibited from shutting off service during winter to residential customers who make regular payments of at least 50 percent of their bills. The utilities may require such customers to comply with a levelized payment plan to avoid shut-off, or otherwise must provide such customers with 9-month repayment plans starting at the end of the winter. Disconnects are not permissible if deemed detrimental to the health or safety of any household member.

In Nevada, customers can take advantage of LIHEAP or the Energy Share Program. Disconnections are not permissible when the temperature is 15° F or below and 105° F or above. Disconnection is delayed for 30 days, with one renewal, if the customer has a medical emergency. Qualifying customers must pay bill in instalments within the next 90 days. Elderly and handicapped customers must have 48 hours notice prior to disconnection.

Atlanta Gas Light

AGL facilitates a variety of programs that are offered by non-profit organizations and state and local agencies to assist qualified individuals with their natural gas bills. The LIHEAP program in the AGL service territory appears to be administered by the regulated division of SCANA Energy, a natural gas marketer. AGL also supports a variety of energy efficiency conservation programs that are oriented to low income individuals, and the company has a Senior Citizens Discount Program. Senior citizens who are 65 years of age or older and have a total annual combined household income of $14,355 or less are eligible for up to a $14 monthly discount on their Atlanta Gas Light Company base charge. Natural gas service must also be in the customer's name to be eligible.

Atlanta Gas Light and the Georgia Public Service Commission also assist those in need through the Home and Heartwarming Project, which is a joint effort with the Georgia Environmental Facilities Authority and Resource Service Ministries. This new program, in which Atlanta Gas Light will invest $1 million over the next 12 months, provides weatherization services and natural gas equipment repair or replacement for qualified senior and low-income households that receive natural gas from the AGL system.

In Georgia, utilities may not disconnect customers between November 15 and March 15 when the forecasted low temperature for a 24-hour period beginning at 8:00 A.M. on the date of the proposed disconnection is below 32 degrees. No disconnect can be completed if illness would be aggravated. Residential service will not be disconnected if at 8 A.M. on the scheduled disconnection day, a National Weather Service Heat Advisory or Excessive Heat Warning is in effect for the county of the scheduled disconnection.

Northern Illinois Gas Company (NICOR Gas)

Besides participating in LIHEAP and the Salvation Army's Energy Share Program, NICOR also facilitates the Illinois Home Weatherization Assistance Program (IHWAP) that provides weatherization services to low income homes. The company also offers a package of benefits to assist activated guard and reservists who reside in their service territory. Customers may not be disconnected when the temperature is lower than 32 degrees Fahrenheit. NICOR must offer payment plan of 10% down payment and equalized billing over the next 4 to 12 months.

CenterPoint Energy Resources

CenterPoint's Minnesota based utility operation facilitates the federally funded Low Income Home Energy Assistance Program, the Salvation Army's Energy Share program and crisis assistance offered by counties.

The company's Gas Affordability Program builds off the LIHEAP program to help low-income customers in Minnesota pay their natural gas bills. To qualify for the program, customers must have already received a LIHEAP grant for the current heating season. If accepted into the program, customers can receive credits on their monthly natural gas bill.

The Gas Affordability Program offers the following benefits:

1. A monthly GAP Affordability Credit for current natural gas charges. A customer's monthly natural gas charges will be estimated for the remaining months of the program year and then averaged to provide a fixed monthly bill amount for current charges. CenterPoint Energy will credit the account for current gas charges that are greater than 6 percent of a customer's annual household income. The flat amount for current natural gas charges will not exceed 6 percent of a customer's annual household income.

2. CenterPoint offers a matching GAP instalment credit for any past due natural gas charges on a customer's account prior to enrolment in the Gas Affordability Program. CenterPoint Energy will apply LIHEAP grants to the past due balance. If there is a past due balance remaining, CenterPoint Energy will create a GAP Instalment Plan for the remaining amount to be paid over 12 to 24 months. Each month a customer pays the GAP Instalment amount, CenterPoint Energy will match it with an equal amount in credit. This matching credit will be applied after CenterPoint Energy receives the customer's GAP payment. If customers participating in the program make their monthly instalment payments, they will be paying for only one-half of the pre-program past-due balance.

Minnesota law provides that a public utility must not disconnect the utility service of a residential customer if a household member is in active military duty provided that the customer enters into an agreement with the utility to make payments toward his or her utility bill.

There is a disconnect ban if health of a household member would be adversely affected. A medical certificate from a doctor is required.

CenterPoint cannot disconnect utility service to a household where a member of the household has been called into active duty if:

1. the household income is below state median or the household is receiving energy assistance and enters into a payment agreement where the customer pays 10% of monthly income toward the bill and remains "reasonably" current; or

2. the household income is above state median income and enters into a payment agreement "establishing a reasonable payment schedule that considers the financial resources of the household and the residential customer remains reasonably current w/ payments under the payment schedule."

The State of Minnesota set up the Cold Weather Rule to help customers who cannot pay their gas bill in full. It does not completely stop winter disconnections but provides customers extra protection from October 15 through April 15.

Public Service Electric Gas

PSEG participates and promotes the federally administered LIHEAP program, but also provides access to variety of other services.

NJ Lifeline is a $225 yearly credit for a customer's electric or gas bill. Applicants must be 65 years old, or a disabled adult at least 18 years old who is receiving Social Security Disability benefits. Annual income must be under $24,432 for a single person or $29,956 for a married couple.

NJ SHARES helps people going through short-term financial problems. To be eligible, customers must not be eligible for the Low Income Home Energy Program and the applicant's gross monthly income must not exceed 400 percent of the Federal Poverty Level. Once approved, qualifying customers can get up to $700 for their gas bill(s) and up to $300 to pay electric bill(s).

New Jersey electric and gas utilities have also joined together to develop and sponsor New Jersey Comfort Partners - a special partnership program to help customers save energy and money by making homes more energy-efficient.

From November 15 - March 15, PSEG cannot disconnect customers receiving LIHEAP, other financial assistance or households unable to pay overdue amounts because of unemployment, medical expenses, or recent death of spouse. Customers eligible for PSEG's Winter Termination Protection Program are placed on a budget plan and cannot be disconnected as long as they make good faith payments. During the heating season, New Jersey utilities may not ask for a security deposit. As well, disconnection is delayed 60 days with certification of medical emergency, and it may be renewed every 60 days as necessary. Commission approval is required for disconnection to medical emergency customers.

Puget Sound Energy, Inc.

Puget Sound Energy's HELP Program provides additional bill-payment assistance beyond the federal LIHEAP program to qualified PSE customers. Eligible customers can receive up to $750 per year in credits to lower their electricity or natural gas bills. Depending on the county in which customer lives, the maximum household income for eligibility ranges between 125 percent and 150 percent of the federal poverty guidelines. HELP assistance is offered year-round to eligible customers.

Between November 15 and March 15, disconnection is prohibited if the customer agrees and adheres to a monthly payment during the winter period. Protection is also in place for hardship customers who qualify or apply for energy assistance.

Disconnection is delayed for 30 days if a medical emergency exists. Customers need written certification from a doctor; can recertify twice within 120 days, and must pay 10% of their delinquent balance and agree to pay the balance within 120 days. Puget Sound may not require payment of more than seven percent of the customer's monthly income. In addition, the customer must pay one-twelfth of any billings from the date application is made through March 15th. If the customer does not pay the past-due bill by the following October 15th, the customer will not be eligible for protection from disconnection until the past-due bill is paid.

Wisconsin Gas LLC (WE Energy)

Wisconsin Gas operates as WE Energy in both Wisconsin and Michigan.

In Wisconsin, the Wisconsin Home Energy Assistance Program (WHEAP) administers the federally funded Low Income Home Energy Assistance Program (LIHEAP) and Public Benefits Energy Assistance Program. LIHEAP and its related services help over 100,000 Wisconsin households annually. In addition to regular heating and electric assistance, specialized services include:

- emergency fuel assistance,
- counselling for energy conservation and energy budgets,
- pro-active co payment plans,
- targeted outreach services,
- emergency furnace repair and replacement.

Wisconsin's Public Benefits program, which encompasses energy conservation, renewable energy development and low-income services, was created in 1999. Public Benefits Funds are managed by the Wisconsin Department of Administration (DOA).

In Michigan, the Home Heating Credit (HHC) is designed to assist low-income families with the cost of heating their homes. The HHC is federally funded through LIHEAP, U.S. Department of Health and Human Services. Under provisions set forth in the State Income Tax Act, the Department of Human Services (DHS) administers Michigan's Energy Assistance programs, and the Michigan Department of Treasury processes the Home Heating Credit claim and issues payments.

WE Energy supports the Service members Civil Relief Act (SCRA). The Act was established to provide relief from potential hardships for families of persons called to active duty. The Act helps families avoid service interruptions and adverse credit reporting.

10.2 Please describe the assistance programs administered by Canadian regulated companies such as Terasen Utilities, Union Gas and Enbridge. Please provide the amount contributed, the number of customer accounts that have benefited, and the operational costs earmarked for these programs. In Terasen's view, is it not true that U.S. utilities have to implement social policy tools of their respective state and federal governments and are more at risk than their Canadian counterparts in revenue recovery?

Response:

Terasen Gas does not agree with the position that U.S. utilities having to implement social policy tools are more at risk than their Canadian counterparts in revenue recovery. In Terasen's view, U.S. utilities participating in income assistance programs face lower risk than their Canadian counterparts that do not have similar programs. Income assistance programs lower the overall bad debt that a utility experiences by shifting payment responsibility to the programs and reducing the number of customers who cannot afford to pay their bills. Canadian utilities, including Terasen Gas, that do not participate in income assistance programs transfer their budgeted bad debt responsibility to their rates. However bad debt above budgeted levels is borne by shareholders. Canadian utilities without access to similar social assistance programs therefore face more risk than comparable US utilities.

Comparing US and Canadian Income Assistance Programs

The majority of US utilities offer some type of assistance to customers who have problems paying their bills. Many of these programs are explored in question 10.1. A number of Canadian utilities in different jurisdictions partner with social agencies to support low-income assistance programs[3]. However, to Terasen Gas' knowledge there is no Canadian province that has a federal, local government or utility-funded program targeting low-income consumers. In March 2009 the Ontario Energy Board recommended implementation of a low income energy assistance program. A summary of the process is discussed below.

Low-income Assistance in Ontario under Review

In July of 2008, the Ontario Energy Board (OEB) initiated a consultation to examine issues associated with low-income energy consumers in relation to their use of natural gas and electricity. The purpose of the consultation was to assist the Board in gaining a better understanding of those issues and in considering the need for, and nature of, measures that could address the challenges facing low-income energy consumers in Ontario.

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[3] For a representative sample of programs offered in Canadian provinces and territories, please refer to the Attachment 10.2.

In March 2009, the OEB in its Report of the Board for Low-Income Energy Assistance Program reported that it is important that there be a comprehensive and province-wide approach to assisting low-income energy consumers.

The Board's policies for implementation of a "Low-Income Energy Assistance Program", or "LEAP" has three components: (1) temporary financial assistance for low-income energy consumers in need; (2) the benefit of access to more flexible customer service rules on matters such as bill payment and disconnection notice periods; and (3) targeted conservation and demand management programs. With respect to the financial assistance component, LEAP builds on the "Winter Warmth" programs in which a number of distributors already successfully participate.

The Board has formed two working groups, the Financial Assistance Working group and the Conservation Working group, to complete the work necessary to implement LEAP. A short-term framework for 2010 was expected before the end of July 2009 and program plans are anticipated for 2010.

Figure 2: Low-income Assistance Programs

Income Assistance Programs	Terasen Utilities	Union Gas	Enbridge Gas
Active payment assistance for low income customers			
Senior citizens discount programs			•
Arrangements for customers to programs administered by local and federal governments			
Incorporate special tariff for low income customers			
Regulations regarding disconnection in cold weather			
Regulations regarding disconnection of military personnel and forgiveness of non-payment			
Special assistance for social service agencies, schools or religious institutions (Emergency Energy Fund)		•	•
Partnership with the United Way		•	•
Partnership with employees			
Utility corporate giving program			•

None of the three Canadian utilities reviewed appeared to be subject to specific regulation related to cold weather disconnections. This likely reflects the extensive climate differences that exist in each company's service territory. Terasen Gas' internal policy regarding disconnections reflects the company's commitment to customer safety.

Enbridge

Enbridge has two energy efficiency Programs targeted specifically to low income customers.

Through the Home Weatherization Retrofit program Enbridge provides income-eligible participants in the Greater Toronto Area with free home energy assessment and weatherization upgrades at no cost to improve the energy efficiency of their home. Program participants can save between 15 to 75% on their monthly gas bills. Green$aver will conduct a thorough energy assessment and use the assessment to identify cost-effective energy efficient recommendations to implement, including draft-proofing and insulation. Green$aver will also be responsible for implementing the measures in each home with their experienced retrofit crews. Approximately 300 qualifying low-income Enbridge Gas customer households will benefit from this pilot program.

The "Enhanced Thermostat, Aerator, Pipe wrap, Showerhead Program," referred to as "TAPS" offers qualifying low-income families and individuals free energy saving tools. Recipients are provided the products to install equipment themselves.

In addition to energy efficiency programs the company also offers a targeted program for seniors. The Golden Age Service program for residential customers 65 years or older includes a variety of options including, the option to pay monthly gas bill after receiving pension cheque, the removal of late fees, waiving of security deposits and special payment arrangements should senior citizens fall behind in payments.

Enbridge Gas Distribution established the Winter Warmth program in 2004 as a joint venture with the United Way and its network of community agencies. The program helps low-income families and individuals who are living at or below the poverty line, and who are experiencing difficulty paying their natural gas heating bills. In 2006, Enbridge also partnered with five other utilities to ensure that all eligible households were taken care of through the winter season. During the 2006/2007 winter season, Enbridge was able to assist over 700 households with their natural gas heating bill. Since its inception, Engridge has assisted close to 4,000 households with their heating bills.

- In the 2008 - 2009 winter season, Enbridge contributed approximately $523,000 to the Winter Warmth program. Over 1,400 customers benefited and the average grant per applicant was $355. Each year since 2004, Enbridge allocates $300,000 to the Winter Warmth Program[4].
    - Enbridge donated an additional $300,000 to the Winter Warmth Fund following "The Garland Settlement", a 1994 class action claim[5] against Enbridge. A

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[4] Manny Sousa, Manager Community Relations, Public and Government Affairs, Enbridge Gas Distribution, July 14 2009

[5] In 1994, Enbridge, was served with a class action claim seeking, among other things, a declaration that the OEB approved 5% late payment fee paid by Enbridge's customers since 1981 is interest that exceeds the amount permitted by the Criminal Code of Canada, and that by collecting the late payment fee, Enbridge had been unjustly enriched and those who paid the fee should be entitled to restitution. In

settlement of the suit included in part $5 million to be paid in equal instalments to the Winter Warmth Fund.

- In the 2007 – 2008 heating season Enbridge contributed $300,000 plus $354,000 from the Garland Settlement to Winter Warmth. A total of 700 applicants without the Garland Settlement top up and 1,124 with the top up benefited. The average grant per participant was $ 353. [6]

Operational costs for the Winter Warmth program are kept low as the infrastructure to deal with energy assistance is already in place and is shared with other programs like the Emergency Energy Fund and Share the Warmth programs.

Information was not available regarding Enbridge's contribution to other low-income assistance programs.

Union Gas
Union Gas has developed a free energy efficiency and conservation program, "Helping Homes Conserve", targeted at low-income homeowners and low-income tenants who pay for their energy bills directly and are Union Gas customers. Low-income participants benefit from free installation of an Energy Saving Kits (which contain up to 2 low-flow showerheads, two faucet aerators, and pipe insulation) and the free installation of a programmable thermostat. Customers must have a natural gas water heater to qualify for the ESK installation, and a natural gas furnace to qualify for the programmable thermostat installation.

Union Gas also partners with local United Way agencies to deliver the Winter Warmth Program. Winter Warmth is designed for low-income families and individuals living at/or below the poverty line who have exhausted all other sources of financial support. Approved households receive a one time grant. Upon successful acceptance to the program, the funds are credited to the heating bill.

- In the 2007 – 2008 heating season Union Gas contributed $217,340 to the Winter Warmth program. There were 623 applicants in the Union Gas Service area and the average grant paid was approximately $366. Funds to the program are allocated according to the level of need in each community and usage of the funds depends on the different communities. [7]

December2006 the court approved settlement of the claim commenced against Enbridge for $22 million. Annual Report 2008

[6] Enbridge Gas Distribution Inc. Consultation on Energy Issues Relating to Low Income Consumers, Information Requests, Board File No. EB-2008-0150http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0150/EGDI_InfoReqResponse_20081007.pdf

[7] Union Gas, Consultation on Energy Issues Relating to Low Income Consumers, Information Requests, Board File No. EB-2008-0150 http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0150/UNION_SUB_InfoReqResponses_20081008.pdf

Terasen Gas

Terasen Gas does not currently have any programs that specifically target low-income customers. The utility is in the process of developing energy efficiency and conservation programs for low income customers.

Risk Assessment

Social programs in the US aimed at assisting low-income families meet their energy needs puts US utilities at less risk then their Canadian counterparts in revenue recovery.

Concentric's research[8] indicates that the majority of U.S. gas and electric utilities have an explicit funding mechanism, such as a customer surcharge or a separate tariff rider, for the low income energy assistance programs which they offer. A few utilities have been allowed to embed the cost of low income programs within their existing rates for electric and natural gas service. The funding mechanisms are based on customer usage (i.e. a specified amount per therm for natural gas customers and per kilowatt hour for electric customers) and those which are a flat monthly surcharge regardless of customer. The vast majority of U.S. utilities apply the tariff rider or monthly surcharge to residential customers only. However, there are notable exceptions, such as Maryland, where low income programs are funded primarily by commercial and industrial customers.

Canadian utility programs are generally designed to provide emergency assistance (i.e., shutoff protection) and energy efficiency, rather than direct rate assistance. The emergency assistance programs are funded through voluntary contributions to social welfare agencies such as the United Way, while the energy efficiency programs are funded through government grants and utility contributions.

The Terasen Gas position is that low-income assistance programs reduce the likelihood of bad debt and therefore reduce the risk to the utility. Research analysis of the US experience by the Low-Income Energy Network in Ontario found that there are costs offsets due to low-income programs. Specifically, the US experience indicates that "…bad debt decreases because payment responsibility for portion of bill is transferred to higher income households and because low-income customers with more affordable bills pay better."[9]

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8 Concentric Energy Advisors, A Review of Low Income Energy Assistance Measures Adopted In Other Jurisdictions Supplemental Report- Prepared for: The Ontario Energy Board, October 21, 2008

9 Low-Income Energy Network Presentation to Ontario Energy Board (EB-2008-0150) http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0150/presentation_LIEN_20080919.pdf#topic3

Attachment 10.2 includes:

- **Union Gas,** Consultation on Energy Issues Relating to Low Income Consumers, Information Requests, Board File No. EB-2008-0150. http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0150/UNION_SUB_InfoReqResponses_20081008.pdf

- **Summary of Low Income Assistance Programs in Canada** (due to amount of detailed information contained in this spreadsheet it is not reasonable to print in a legible format and is therefore attached electronically only) http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0150/LowIncomeConsultation_Appendix+C.xls

10.3 Please compare the regulatory deferral accounts, gas cost deferrals, weather and sales stability accounts, interest rate, and tax true ups of TGI with each of the eight comparable utilities.

Response:

Please see the following table that compares the deferral account of TGI and the eight comparable utilities.

Deferral Account Comparison to Concentric Sample of US Utilities					
Utility	**Regulatory Deferral Accounts**	**Gas Cost Deferral Accounts**	**Weather & Sales Stability Deferral Accounts**	**Interest Rate Deferral Accounts**	**Tax Related Deferral Accounts**
Terasen Gas Inc.	Demand Side Management and NGV Conversion Grants, Pension & Insurance expense, OPEB funding	CCRA, MCRA & Revelstoke Propane; capture the difference between cost and revenue collected by rate. Designed to mitigate rate volatility for customers	RSAM- designed to mitigate rate volatility for customers and act as a decoupling mechanism for TGI. SCP Mitigation revenues- reduce the risk of over or under forecasting SCP revenues	Deferred interest account	Property tax; (Taxes accounted for on a taxes payable method) Income tax true ups as they relate to changes in tax law and rates
Atlanta Gas Light Co.	Rider for Pipeline Replacement Costs (Georgia); rider for Environmental remediation liabilities (Georgia)	No; do not purchase gas	Straight fixed variable rate (Georgia); Decoupling (Virginia); Weather Normalization (New Jersey and Tennessee)		
CenterPoint Energy Resources	Environmental expense tracker (MN); storm restoration deferral; deferral for pension and OPEBs	Pass through gas costs	Weather normalization or weather mitigation mechanisms in AR, LA, OK, and parts of Texas		
Michigan Consolidated Gas Co.	Uncollectibles true-up; deferral for pension expenses and OPEBs,environmental remediation costs 2/	Pass through gas costs			
Northern Illinois Gas Co.	Deferrals for OPEBs; rate case expense; pension expense; environmental costs	Pass through gas costs	80% Straight Fixed Variable Rate		
Public Service Electric Gas	Deferrals for Environmental remediation; pension and OPEBs; social benefits charges; New Jersey Clean Energy; stranded and restructuring costs;	Pass through gas costs	Decoupling		
Puget Sound Energy, Inc.		Purchased Gas Adjustment			Income and property tax true ups 1/
Southwest Gas Corp.	pension expense	Purchased Gas Adjustment	Decoupling (CA); declining block structure (NV)	Interest Balancing Account (Nevada)	
Wisconsin Gas LLC	deferrals for pension and OPEBs; electric transmission expense; bad debt expense;environmental costs	Pass through gas costs			

From Company 10Ks

All US Companies collect income taxes on a normalized basis

1/ Puget is primarily an electric utility and its deferral amounts largely specific to its electric operations
2/ Parent is DTE Energy, primarily electric and its deferral accounts largely related to its electric operations

The TGI Revenue Requirements for 2010 and 2011 do not have any significant change to deferral accounts that would alter the risk profile of TGI.

11.0 Reference: Exhibit B-1, Cover Letter p. 19 30 Year GCB Yields

The Cover Letter states that the ROE allowed by the formula is to some extent "luck of the draw," being highly dependent on the month used for the forecast of the GCB yield.

11.1 Please comment if this observation had been made when the first AAM formula was introduced in 1994 and during its subsequent adjustment hearings in 1999 and 2006.

Response:

TGI is unaware whether this observation was made explicitly in prior proceedings. The formula was originally based on five days of observations in October of the spot spread between 10 year and 30 year GCB yields which was subsequently adjusted to include the entire month of October each year. As illustrated in the charts on page 20 and 23 of the Application, the volatility of the movement in the forecast GCB 30 year yield has been on a steady downward trend since 2000 and up until the end of 2005 reflected relatively modest changes from month to month each year with a few more notable changes in the winter of 2000 and the summer of 2003. However, since the beginning of 2007 the movements in the long bond forecast have been quite volatile. This would have led to significantly different allowed ROEs had a different month been selected for establishing the rate for the following year.

11.2 Is it only with the passage of time that the allowed ROE formula has become "luck of the draw"?

Response:

See response to CEC IR 1.11.1 above. The observation has more significance during periods of greater volatility in movements of the forecast long GCB yield. Between November 2008 when the official yield for 2009 and January 2009 when it became effective, the implied AAM based ROE would have changed by approximately 60 basis points. Similarly, between the official setting of the 2006 ROE based on the November 2005 consensus forecast following the last BCUC amendment to the AAM and the summer of 2006, the implied ROE would have increased approximately 50 basis points.

TGI believes that investors return requirements on utility investments do not fluctuate dramatically from month to month or even year to year and certainly not to the extent implied by the BCUC AAM in recent years.

12.0 Reference: Exhibit B-1, Cover Letter p. 24 TGI's Changing Business Risk

The Cover Letter describes some components of the business risks and states that the risk factors determine whether the utility will be able to recover its investments in rate base over time and affect its ability to achieve its allowed return.

12.1 Please provide the allowed and achieved ROEs for TGI, TGVI and TGW between 1994 and 2008.

Response:

Please refer to the following tables for a summary of allowed and achieved ROEs for TGI from 1992 to 2008, and for TGVI and TGW from 1996 to 2008.

TERASEN GAS INC.
COMMON EQUITY RETURNS AND OTHER COMPARISONS
FOR THE YEARS ENDED

	ROE		
Years	Allowed	Achieved Pre-Earnings Sharing	Achieved Post-Earnings Sharing
(1)	(2)	(3)	(4)
12/31/1992	12.25%	9.060%	N / A
12/31/1993	N / A	11.909%	N / A
12/31/1994	10.65%	9.727%	N / A
12/31/1995	12.00%	12.030%	N / A
12/31/1996	11.00%	11.803%	N / A
12/31/1997	10.25%	11.266%	N / A
12/31/1998	10.00%	9.405%	9.703%
12/31/1999	9.25%	10.698%	9.974%
12/31/2000	9.50%	10.748%	10.124%
12/31/2001	9.25%	9.375%	9.313%
12/31/2002	9.13%	9.729%	N / A
12/31/2003	9.42%	10.226%	N / A
12/31/2004	9.15%	9.344%	9.247%
12/31/2005	9.03%	10.784%	9.907%
12/31/2006	8.80%	10.472%	9.636%
12/31/2007	8.37%	10.729%	9.550%
12/31/2008	8.62%	* 10.637%	* 9.628%

Notes:
1992 includes Fort Nelson Service Area.
1993 to 1994 labour force includes Fort Nelson Service Area.
L-T Canada Yields in 1992 to 2003 actuals are the range of yields on the benchmark Government of Canada bond in the respective year.
* Not finalized.

TERASEN GAS (VANCOUVER ISLAND) INC.
COMMON EQUITY RETURNS AND OTHER COMPARISONS
FOR THE YEARS ENDED

		ROE	
Line No.	Years	Allowed	Achieved
	(1)	(2)	(3)
1	12/31/1996	11.70%	not available
2			
3	12/31/1997	10.82%	10.106%
4			
5	12/31/1998	10.01%	not available
6			
7	12/31/1999	9.09%	9.704%
8			
9	12/31/2000	9.66%	7.636%
10			
11	12/31/2001	9.36%	9.444%
12			
13	12/31/2002	9.26%	9.920%
14			
15	12/31/2003	9.92%	8.959%
16			
17	12/31/2004	9.65%	9.879%
18			
19	12/31/2005	9.53%	11.006%
20			
21	12/31/2006	9.50%	10.425%
22			
23	12/31/2007	9.07%	10.964%
24			
25	12/31/2008	9.32%	10.766%

TERASEN GAS (WHISTLER) INC.
COMMON EQUITY RETURNS AND OTHER COMPARISONS
FOR THE YEARS ENDED

		ROE	
Line No.	Years	Allowed	Achieved
	(1)	(2)	(3)
1	12/31/1996	11.75%	not available
2			
3	12/31/1997	11.00%	11.00%
4			
5	12/31/1998	10.75%	9.82%
6			
7	12/31/1999	10.00%	10.57%
8			
9	12/31/2000	10.25%	8.96%
10			
11	12/31/2001	10.00%	7.76%
12			
13	12/31/2002	9.73%	10.12%
14			
15	12/31/2003	10.02%	9.29%
16			
17	12/31/2004	9.75%	9.38%
18			
19	12/31/2005	9.63%	10.51%
20			
21	12/31/2006	N/A	8.96%
22			
23	12/31/2007	8.97%	8.97%
24			
25	12/31/2008	9.22%	9.22%

12.2 For those years where the achieved ROEs fall short of the allowed, please provide explanations.

Response:

When an achieved ROE is reported below the allowed ROE for a particular year, the major cause for this deficiency is due to forecasting variances including, but not exclusive to: rate base, cost of service and volumes (excluding weather for TGI due to the RSAM mechanism) .

With respect to TGI, the shareholder is at risk for this shortfall. TGI's achieved ROE was reported below the allowed ROE for the years 1992, 1994, 1998, and 2004.

For TGVI, the achieved ROE was below the allowed ROE for years 1997 and 2000. For the years 1996 to 2002 the Vancouver Island Pipeline Agreement ("VINGPA") provided an ROE component of 3.625% over the Government of Canada long-term bond rate. From 2003 onward, the ROE is set by the BCUC. The VINGPA also provides for a reduction in the achieved ROE of $1.867 million for the years 1996 to 2011. Variances from the approved result from O&M cost variances that company is at risk for.

For TGW, the achieved ROE was below the approved ROE for the years 1998, 2000, 2001, 2003, and 2004. In the years prior to 2005, TGW did not have approval for a deferral account (similar to TGVI) to capture differences between the actual and approved ROE. However, BCUC Order No. G-14-04, Page 5, Item 7 approved an ROE variance deferral account beginning in 2005.

13.0 Reference: Exhibit B-1, Cover Letter p. 24 Changing Business Risk

"Under the current ROE formula mechanism, TGI is discouraged from investing capital in the utility facilities beyond that which is required to meet the Company's basic obligation to serve existing customers in its service areas, much less to respond to the changing consumer demands and government policy directives. However, unless TGI participates in meeting business and government policy challenges it will see its traditional business and share of the energy delivery market erode and with it, its ability to recover its existing investments over time."

13.1 Please confirm that TGI, in its Energy Efficiency and Conservation Application (May 28, 2008), proposed to extend its amortization period of capitalized DSM costs from 3 years to 20 years. TGI also proposed that costs that were expensed were to be capitalized into the deferral account.

Response:

The Terasen Utilities believe that the Company's basic obligation to serve existing customers in its service areas include undertaking Energy Efficiency and Conservation ("EEC") (or Demand Side Measures) activities on behalf of its customers. The reasons for this are:

- EEC activities are in the best interests of customers as they help customers reduce and manage their energy bills and therefore improve their carbon footprint; and
- Recent changes to the Utilities Commission Act (the "UCA"), (See Section 44.1 of the UCA) require utilities to pursue energy conservation and efficiency activities and programs.

The Terasen Utilities believe that assisting customers to help them manage their energy consumption by providing them with information and programs fulfill the obligations that TGI has under the UCA.

In the TGI-TGVI 2008 Energy Efficiency and Conservation Programs Application submitted to the BCUC on May 28, 2008, TGI-TGVI proposed to treat the incremental EEC expenditures above amounts already approved as part of TGI PBR Extended Settlement and TGVI RR Extended Settlement as capital, by way of a regulatory asset deferral account. It was proposed that these incremental EEC expenditures be charged to a regulatory asset deferral account on a tax-adjusted basis, the balance of which was to be amortized over twenty years, with amortization commencing the year following that in which the expenditure was made. An amortization period of 20 years was selected to match the benefit received by customers from the EEC expenditures resulting in appliance and energy system installations with a weighted average measurable life of 22.5 years. In addition to closely matching the cost recovery to the period over which benefits will accrue to customers, the proposed amortization period was expected to smooth impacts to rates from the proposed increase in expenditure.

The Commission in its decision (Order No. G-14-06) accepted TGI-TGVI's proposal to record the approved EEC expenditure in a regulatory asset deferral account amortize the EEC expenditures over periods not to exceed 10 years, rather than the 20 years as proposed. The Commission was of the view that a ten year amortization period provided a reasonable balance, considering both the DSM objectives and customer impact.

13.2 Please confirm that TGI, in its Customer Care Enhancement Project CPCN Application, is applying for approval of a $155 million project including AFUDC that would be capitalized. Please elaborate on the current billing costs and customer care costs. Are they currently expensed or capitalized?

Response:

The Customer Care Enhancement Project CPCN Application from June 2, 2009 sets out a project implementation cost of $155 million including AFUDC. This amount is not exclusively comprised of costs that would be capitalized but rather includes both a capital and a deferred O&M component. Total project capital and AFUDC is $141 million, and deferred O&M is $14 million. The cost of service that is based on this project implementation cost and the future cost of O&M represents the optimal mix of resources that results in the lowest cost of service to customers.

The implementation of the project will result in the restructuring of the Company's outsourced customer care function so that core customer care services may be in-sourced and delivered by Terasen Gas directly using information technology and facilities assets that it owns and operates. Customer care services are currently provided through an outsourcing arrangement and include customer contact, billing and payment processing, collections, contract management, meter reading, and customer information system support and maintenance. The cost of these services is currently treated as an O&M expense and is not capitalized.

Terasen Gas does not believe that the current outsourcing arrangement is sustainable and must be fundamentally restructured in order for it to continue to serve customers, which constitutes the Company's basic obligation. Because the current outsourcing arrangement is not sustainable, the Customer Care Enhancement Project is required in order for Terasen Gas to continue to meet its basic obligation to customers. This project does not serve as a vehicle for investing capital beyond meeting this requirement.

14.0 Reference: Exhibit B-1, Cover Letter, pp. 24, 25 Risk Definitions

The cover letter uses the term "risk" in many ways without always defining exactly and precisely what is meant by the word "risk" from a financial economics perspective.

14.1 Please clarify what exactly is "at risk" for TGI. Are earnings per share at risk (assuming number of shares does or does not rise and fall to maintain a constant equity thickness)? Are costs at risk (i.e., costs that can or cannot be passed on to customers or hedged so as to remove the risk)?

Response:

In discussions of business risk for TGI, it is useful to consider short term and long term risks. In the short term the focus is generally on TGI's ability to earn a fair return on its investments from year to year. In the longer term the risk relates to whether or not the utility will be able to recover the cost of its investments over their useful lives and earn a fair return on such investment over the long run. Earnings per share for a privately held utility are not a particularly significant measure as this metric is typically referenced when looking the performance over time for publicly traded entities[10].

Costs, both operating and capital related must be recovered in the short and long term. The fact that a regulator allows costs to be recovered in rates does not in and of itself eliminate the business risk though a disallowance of costs in the regulatory context crystallizes a loss. Ultimately customers must be willing to buy and pay for the service. If rates are not competitive either on a cost per unit energy basis or the product/service falls out of favour and customers leave the system, then costs, even though allowed in rates, can become unrecoverable in the long run.

TGI employs multiple strategies to manage competitive risk including the use of hedging, rate design and cost containment.

14.1.1 To what specific risk factors is TGI exposed on a net, on a total, and per-share basis, after accounting for the ability to hedge, pass on some costs to customers and adjust the equity base?

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[10] Return on invested equity is the more meaningful measure since the equity component of the capital structure is typically managed through dividend policy or through injection of additional equity which may be subscribed for at share values that differ from the average value per share of the outstanding common shares pre-subscription. EPS is a better measure for public companies because it accounts for and reflects the dilution of new equity issuance.

Response:

In the near term, TGI is exposed to credit/collection risk on virtually its entire revenue stream for sales and transportation customers. Events of default on the part of any customer who owes the company money for service other than those who have posted security expose the company to risk of loss. Similarly third party damage claims receivable are subject to collection risk as well.

TGI is/or has been exposed to capital cost disallowances for construction projects and is always exposed to prudency reviews. In some cases the Commission has imposed cost caps on the approval of CPCNs.

Commodity cost volatility/risk is managed through the annual Price Risk Management Plan and Annual Contracting Plan which are both approved by the BCUC. Not withstanding the hedging program and forward fixed price contracts entered into by the Company as well as the credit review measures taken by the Company, TGI is exposed to counterparty default risk. In the event such defaults occur and even though the costs associated would reasonably be expected to be allowed for recovery in rates, should the cost burden result in rates that were not competitive then there is a risk that these costs would not be fully recoverable from customers.

Once rates are set, the majority of O&M costs are at the Company's risk. Unfunded debt for both principle variances and related interest costs are at the Company's risk.

14.2 Please clearly define which risks being faced by TGI are "operational risks" (i.e., risks from competition, changing customer tastes, recessions, political factors, law suits, environmental forces, etc.) that arise from the operation of the business, vs. "credit risks" (i.e., risks of default or changing credit ratings, etc.), vs. "market risks" (i.e., risks from fluctuations in the market price of gas or other commodities, fluctuations in exchange rate or market interest rates or the general stock market, liquidity, etc.) as these risk terms are commonly defined in the risk management profession.

Response:

All of the risks to which TGI refers on pages 24 and 25 of the Application and which are discussed in further detail in Tab 1 are business risks or operating risks. Business risk is the risk that a utility will not be able to earn its cost of capital or recover the invested capital. Business risk comprises the fundamental characteristics of the business (i.e. demand, supply, competition and operating factors) that together determine the probability that future returns to investors will fall short of their expected and required returns. TGI also faces credit/financial risks and the systematic market risks referred to in the question as market risks.

14.3 Is volatility always the same as risk, or can these concepts be different? And if these concepts are different how are they different?

Response:

Volatility or variability in returns is one aspect of risk. However, the probability that, in the long-run, investors will not fully recover the capital which they have committed to the enterprise is not necessarily reflected in the volatility of returns, be they stock market returns or accounting returns. For example, a utility might be protected by contracts or have a regulatory framework which mitigates its short-term risks but still face long-run capital recovery risks which are not captured in the year to year variability in returns, and which is not captured in measures of market volatility such as beta.

14.4 If TGI grows faster but its value also becomes more volatile, has TGI's risk increased or decreased or is the effect uncertain? Conversely, if TGI grows more slowly but with less volatility, has TGI's risk increased or decreased or is the effect uncertain? Why?

Response:

The effect is uncertain as the impact on risk will depend on various factors, including the point of departure and the rate of change. In principle, both rapid and slow (or declining growth) can result in higher risk. Rapid growth can result in higher risk during the period of growth due to higher costs and increased customer forecasting risk, potential lag in cost recovery or disallowance of costs incurred to facilitate growth. Slow growth, particularly where there is a decline in customer usage, or declining growth can result in higher longer-term risk because rates become less competitive with alternative energy sources which in turn can further reduce consumption.

14.5 If one stock price is more volatile than another stock price, is the more volatile stock necessarily more risky for the investor?

Response:

No. If some of the risk associated with the volatility of return on an investment in Stock A can be reduced by including Stock A in a well-diversified portfolio, then the observation that Stock A has greater volatility than Stock B does not necessarily indicate that Stock A is more risky than

Stock B. However, the average investor associates risk with the concept of uncertainty about an expected outcome. For such an investor, the observation that the return on Stock A is more volatile than the return on Stock B is strongly supportive of the conclusion that Stock A is more risky than Stock B.

14.5.1 If the value of an index of utility company stocks is more volatile than the value of a broad market index such as the S&P500, does that necessarily mean that utilities are more risky than the market in general? Or, is there a more appropriate way to measure the relevant "risk", for example undiversifiable systematic risk (as captured by the CAPM beta), rather than total risk?

Response:

(a) If some of the risk of investing in utilities can be reduced by including utilities in a diversified portfolio, then the observation that utility common stocks are more volatile than a broad market index does not necessarily imply that utilities are more risky than the market. However, for the average investor, the observation that returns on utility stocks are more volatile than returns on a broad market index supports the conclusion that utility stocks are more risky than is implied by the AAM ROE formula.

(b) According to the Capital Asset Pricing Model ("CAPM"), the risk of investing in a utility stock is best measured by calculating the utility stock's beta rather than by calculating its volatility or standard deviation. However, there are at least three problems with using utility betas, as traditionally estimated using five years of weekly or monthly returns, as a measure of the risk of investing in utility stocks. First, the traditionally calculated betas depend on the correlation, or co-variation, between the returns on the utility stocks and the returns on the market index. Because utility investors invest for the long run, they do not consider the correlation, or lack thereof, between short-run utility returns and short-run returns on the market index as a measure of risk. Utility investors are more concerned about the correlation between the long-run returns on utility stocks and long-run returns on the market index. However, the correlation between the long-run returns is difficult to measure because of the lack of a reasonable sample of long-run returns.

Second, beta is only a measure of risk in the context of the CAPM. If the CAPM fails to predict the relationship between risk and return in the Canadian marketplace, beta is an unreliable indicator of risk. Dr. Vander Weide's testimony provides strong evidence that the CAPM fails to predict the relationship between risk and return in the Canadian marketplace, and, therefore, that the utility beta is not a reasonable measure of risk.[11]

Third, if beta is a reasonable measure of risk, then using the traditional estimate of beta in the CAPM should produce a reasonable estimate of a utility's cost of equity. However, traditionally-estimated betas for Canadian utilities using the last five years of data are in the range 0.25 to 0.30. Multiplying a beta of 0.30 by either a 5 percent or 6 percent risk premium on the Canadian market index yields a utility risk premium of 1.5 percent to 1.8 percent. Adding this utility risk premium to a forecasted yield on long Canada bonds of 3.69 percent produces a cost of equity in the range 5.19 percent to 5.49 percent. Since this result is absurdly low in comparison to current yields on utility bonds, it is reasonable to conclude either that: (1) betas as traditionally measured do not correctly measure the risk of utility stocks; or (2) the CAPM does not apply to the Canadian marketplace.

For these reasons, Dr. Vander Weide measures risk by volatility rather than beta.

[11] The evidence that the CAPM fails to predict the relationship between risk and return in the Canadian marketplace can be described as follows. The CAPM predicts that a company's beta should equal the risk premium on the company's stock divided by the risk premium on the market portfolio:

Beta = *(Risk Premium on Utility Stock) ÷ (Risk Premium on Market Portfolio)*

Dr. Vander Weide's data indicate that either from 1956 to the present or from 1983 to the present the risk premium on utility stocks exceeds the risk premium on the Canadian market index. This evidence is inconsistent with the widely-held belief that utility stocks are less risky than the market index. Thus, Dr. Vander Weide concludes from this evidence that the CAPM does not adequately explain the relationship between risk and return in the Canadian marketplace.

15.0 Reference: Exhibit B-1, Cover Letter pp. 32, 33 Alternative Approaches to AAM

"Furthermore, any continued reliance on a GCB-based formula would require explicit recognition of the shortcomings of the current formula and explicit recognition of the inadequate ROEs that have resulted from the formula; a major re-calibration would be required. Moreover, it would be difficult to address abnormal market conditions that affect long-term government bond yields with this approach."

15.1 The 2009 federal budget and the new federal debt management strategy 2009-2010 which includes the bond program for 2009-2010 revealed that it will increase issuance in all current benchmark maturities. In Terasen Utilities' view, would the 2009 federal budget and the prospect of the federal government posting the biggest deficit in Canadian history of more than $50 billion change the government bond yields? Please explain your answer.

Response:

The bond market and economists recognize that many factors determine the level of Government of Canada interest rates. A single large deficit is unlikely to determine the level of GOC interest rates on an on-going basis. In particular, the recent budget included major stimulus for the economy which either reduced current revenue (for example, lowering tax rates and such programs as the home renovation tax credit) or increased capital spending (i.e. the infrastructure program) which results in a larger deficit in the 2009-2010 fiscal year but is also expected to increase economic activity in the short run and improve the efficiency of the nation's infrastructure in the long run. Each of these developments will contribute to increases in national economic activity and revenue and potential budgetary surpluses in the longer term that will be used to retire the debt arising out of current initiatives. The Government of Canada has established a strong reputation with domestic and international lenders in paying down outstanding debt out of budgetary surpluses in the past. The debt markets reaction to these proposals has been a non-event as short term GOC rates have declined significantly since the date of the budget (January 27, 2009) and longer term rates (30 year benchmark bonds) have remained at about the same level of approximately 3.8%. The capital markets have not reacted in any material way to the prospect of a large budgetary deficit in 2009 and an expected series of declining deficits out to 2014-2015.

16.0 Reference: Exhibit B-1, Cover Letter, pp. 32, 33 Formula Adjustment Factor

It appears that lowering the formula adjustment factor from .75 to .50 is helpful to TGI when interest rates are falling since a smaller adjustment factor keeps the allowed return from falling as fast as market rates. Conversely, a larger adjustment factor seems more advantageous to TGI when interest rates are rising since TGI's return would be adjusted upwards more quickly with a larger adjustment factor.

16.1 Does TGI perceive a problem with the adjustment factor per se, or is the perceived problem with the level of the allowed ROE that has been arrived at today through historical application of the AAM over the past several years when interest rates were falling?

Response:

Overall, TGI believes the return produced by the current AAM has failed to produce a fair return and that is why TGI is seeking to have the AAM set aside and new Benchmark return established for the Terasen Utilities. This is a result of a number of factors including the absolute level of, and reliance on, one external observable factor being the forecast Long GCB yield; the adjustment factor itself which appears based on the evidence presented by Dr. Vander Weide to be lower smaller than 75% adjustment factor assumed in the current AAM, and implicit equity risk premium build into the formula.

16.2 If the level was re-set to some level considered appropriate by TGI, would a .75 or .50 adjustment factor then be optimal going forward?

Response:

If the Commission recalibrates the Benchmark ROE to an appropriate level it is possible that a formula could be established that would adjust the annual allowed return thereafter for a period of time subject to periodic reviews to ensure the returns continue to be fair and reasonable. Clearly the existing AAM has failed over time to deal with all the factors that affect the appropriate return on equity. A formula AAM is at best a proxy for establishing a return between more detailed examinations by the Commission. The Company attempted to develop alternative formula based approaches but was unable to find additional transparent variables such as a publicly available Canadian utility bond index on which to base such a formula.

Based on the evidence of Dr. Vanderweide and with hindsight, an adjustment factor of 0.50 would have been more appropriate than 0.75 that is used in the current AAM, but simply imposing a lower adjustment factor on the current level of returns would not produce a fair result.

16.3 Assuming that the AAM is still in place, if interest rate moves in an upward trend in future, should a .75 or a .50 adjustment be used?

Response:

As discussed in the Application, the current level of return produced by the formula does not meet the fair return standard. If the current AAM were to be recalibrated to an appropriate starting level, then based on the evidence presented a .50 adjustment factor would appear to be more reasonable than a .75 adjustment factor. However, at current levels of return and forecast Long GCB yields, changing the adjustment factor from .75 to .50 would be punitive to the Terasen Utilities.

17.0 Reference: Exhibit B-1, Cover Letter, pp. 33 & 42 AAM

TGI states that it "is not prepared to propose or commit to an automatic adjustment mechanism at this time." The conclusions on pages 42 and 43 point to the alleged problems with the AAM based on recent widening spreads between long GCB yields and corporate bond yields and the sliding scale which does not match US return data. Terasen Utilities will pursue development of a new AAM in time for implementation in 2011.

17.1 If one adjusted the existing AAM for the changes in GCB versus TGI debt spreads between 2005 and July 2010, what would the impact have been in each year since 2005? What then would be the impact on the sliding scale comparison with US data?

Response:

TGI interprets the request as asking what the ROE in each year from 2006 to 2010 would have been if:

(a) The benchmark ROE and long Canada bond yield had still been the 9.145% and 5.25% specified in the BCUC's March 2006 decision;

(b) The ROE for each year would have been determined by taking 75% of the change in forecast long-term Canada bond yields plus 100% of the change in TGI debt spreads.

The table below shows the results:

	Long Canada Bond Yield	**TGI Spread** [2/]	**ROE as per current AAM**	**ROE with AAM plus change in Spread**
Benchmark	5.25%	130.00		
2006	4.79%	124.75	8.80	8.75
2007	4.22%	130.00	8.37	8.02
2008	4.55%	142.25	8.62	8.39
2009	4.25%	310.00	8.47	9.92
2010 [1/]	4.14%	183.00	8.31	8.84

1/ July 2009 10-year Government of Canada bond yield Consensus Forecast for October 2009 and July 2010 of 3.65% plus June 2009 spread of 0.49% between the 10- and 30-year Government of Canada bond yields.

2/ Indicated spread in basis points for new 30 year TGI issue provided by RBC Capital Markets for each week in November of the preceding year, except for benchmark, which is the average March 2006 spread, and 2010, which is the average indicated spread during June 2009.

Since (1) the point of departure was a benchmark ROE of 9.145% (at a long Canada bond yield of 5.25%) when the allowed ROEs in the U.S. were approximately 10.5%; and (2) there is still a sliding scale factor on the long-term government bond which reduces the ROE by 75% of the change in spread, the average allowed ROE over the period would still be significantly lower than the returns of U.S. utilities. Only in 2009, due to the increase in credit spread, would the allowed ROE have approached 10%.

17.2 If the TGI ROE and Capital Structure are adjusted for the new risks faced by TGI, what does this imply for the setting of ROEs for other utilities in BC, including the sister companies of TGVI, TGW, and FortisBC?

Response:

Of the new risks discussed in detail in Tab 1 of the Application, those relating to Aboriginal Rights Effects on BC Utilities are experienced to some degree by all utilities operating in the province. Those related to BC government policies and climate action related initiatives are also experienced by TGVI, TGW and PNG as natural gas distribution businesses, though Terasen cannot speak for PNG.

The Terasen Utilities believe that the new risks faced by TGI are equally applicable to TGVI and TGW as they go to the competitiveness of natural gas and these are natural gas utilities. As such it is reasonable to continue to set the returns of the sister companies with reference to the new Benchmark ROE being sought in this Application for TGI. Fortis BC is also impacted by government energy policies and Aboriginal rights effects on BC Utilities though they are not impacted in the same way as the Terasen Utilities by the climate action initiatives.

17.2.1 The spreads of those companies are set based on a low risk utility but TGI argues that its risk profile has changed. On what basis could one assume that the spreads of those other companies are unchanged? For example, the risks of TGVI may have fallen with the new BC Hydro RIB rates and the elimination of its own debt deferral account.

Response:

As discussed in the response to 17.2 above and Section 5.2 of the Application, the new risks experienced by TGI are also felt by TGVI and TGW. The BC Hydro RIB rates are postage stamp rates that apply equally in each of the Terasen Utilities service areas and TGVI and TGW rates continue to be substantially higher than those of TGI. In the case of TGW, the Commission opined on the appropriate utility specific risk premium in April 2009 and TGW is not seeking reconsideration of that determination. For TGVI the current rate setting mechanism in place sets rates for certain customer classes with reference to electricity rates and they have moved in lock step with changes to electricity rates so the competitiveness level is essentially unchanged from where it was before the RIB rates were introduced. While the Revenue Deficiency Deferral Account is expected to be reduced to zero in 2009, TGVI does not recover its full cost of service without ongoing Royalty subsidization of its cost of gas for sales customers. The Royalty subsidy will be removed by the end of 2011 at which time there will be substantial upward pressure on rates which would be expected to exceed those of the BC Hydro RIB rates.

18.0 Reference: Exhibit B-1, Cover Letter, p. 34 Equity Thickness and Credit Rating

The Application states that a capital structure with 40 percent common equity ratio in addition to an ROE of 11 percent will appropriately address the requirements that meet the Fair Return Standard.

18.1 Based on the information in your Response to Question No. 8.1 above, what is the minimum level of equity thickness that is expected to be required to maintain an "A" credit rating, recognizing the overall risk of TGI as assessed by the ratings agencies? Is it 40 percent or some lower number?

Response:

TGI is not aware of, nor has it attempted to estimate, the minimum equity ratio or combination of ROE and equity thickness that would be required to maintain an A rating. The minimum equity ratio required to maintain an A rating is not a precise number as it depends on various factors, including the debt rating agency's views of the components of business risk, the regulatory climate and the financial risk arising from its ROE and equity thickness. As noted by Moody's, TGI's credit metrics are weaker than its peers and are at a level that is consistent with credit ratings below the A category. Terasen has maintained its rating in part due to qualitative factors, such as the past business environment and regulatory support. The continued weakening of TGI's credit metrics, recent increases in business risk factors or a perception of increased regulatory risk may lead to a downgrade below the A category. TGI believes an ROE of 11% and equity thickness of 40%, while not guaranteeing an A rating, would enhance the likelihood of maintaining an A rating and make a downgrade more remote.

Further, TGI's Application for a combination of capital structure and ROE in this proceeding represents an overall return which is intended to achieve the three criteria of the fair return, maintenance of financial integrity, ability to attract capital on reasonable terms and conditions, and an opportunity to earn a return on investment commensurate with that of comparable risk enterprises. Although an A credit rating is an important consideration, particularly from the debt holder's perspective, establishing either the minimum equity ratio or minimum ROE necessary to maintain A credit ratings does not address the question of the level of the return (capital structure and ROE) which fairly compensates equity holders.

As the BCUC recognized in its March 2006 cost of capital decision,

> *"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.'"*

18.2 If the answer to the preceding question depends on the ROE (i.e., the credit rating depends on a combination of ROE and equity thickness) then please provide a table showing combinations of ROE and equity thickness that are believed to be the minimums and maximums required to maintain an "A" credit rating.

Response:

As noted in the response to BCUC IR 1.18.1, TGI is unable to respond to the question as posed, as the debt rating agencies do not apply ratings on a purely quantitative basis, as qualitative factors are also considered. Moreover, as discussed in response to BCUC 1.18.1, the minimum combination of ROE and common equity ratio for an A rating does not address the question of what is a fair return for equity holders. Similarly, the maximum combination of ROE and common equity ratio for an A rating does not address that question either.

From a quantitative perspective, Moody's has noted that TGI's credit metrics, in particular the capital structure and interest coverage, are below that required for an A rating. Continued weakening in credit metrics, increased business risk or a less supportive regulatory environment, while maintaining the current low ROE and equity ratio, could see TGI incur a downgrade. Therefore, TGI believes an ROE of 11% and equity ratio of 40% is appropriate to maintain an A rating and address the requirements of a Fair Return Standard.

BUSINESS RISK

19.0 Reference: Exhibit B-1, Tab 1 p. 1 Business Risk - Throughput Level for a Mature Utility

19.1 The Application states that if throughput levels decline for whatever reason, TGI business risk increases. Furthermore, TGI describes that its throughput is influenced by the competitiveness of natural gas to alternative energy sources and also TGI’s ability to attract customers and retain its customer base.

19.1.1 In TGI’s view, which type of utility has more stable throughput levels: a mature, maturing, or a new, developing utility? Please explain your answer.

Response:

An indicator of how TGI business risk has increased relates to the decline in annual normalized throughput levels being transported across the TGI system. TGI capital investments have been made to serve customers over the long term. With declining throughput the costs of these investments must be recovered over a smaller volume, which increases costs to the remaining customers of TGI. Historically, a utilities throughput level would be one indicator of the utility stage of development.

A mature or maturing utility would be expected to have in general more stable throughput levels. A mature utility tends to have a relatively established, diversified, and mature customer base with high customer penetration levels achieved in its service territory. A lower percentage of customer additions to the existing customer base and thus lower customer growth rate indicate that the throughput levels stabilize over time for mature utilities. However, due to changing factors such as a focus on energy efficiency and conservation, even a mature utility may not have stable throughput levels. Technological change, energy efficiency and conservation programs will put downward pressure on use per account over time. Although new customer attachments will serve to offset load lost due to the proceeding factors to varying degrees, low customer additions make it challenging to offset the total reduction caused by reduced consumption from existing customers.

On the other hand, a new or developing utility would be characterized by lack of established customer base and customer growth rate, lower customer penetration rates, and therefore significant variability in use per customer rates and throughput levels due to the growing stage of the business. Customer attachment levels could be greater than the rate of growth in the economy, and customer appliances are more efficient on average for a maturing utility than that of a mature utility.

19.1.2 Does TGI consider itself a mature utility? Please describe in general the historical and expected growth of throughput, rate base and customer base of TGI.

Response:

Yes, TGI does consider itself a mature utility. Over the past ten years, TGI has seen overall throughput decline by approximately 1.2% annually (12% in total, from 1999 to 2008), while at the same time normalized rate base has increased by approximately 8% annually (53.3% from 1999 to 2008). TGI's customer base has grown by an average of approximately 1.1% per year (10% from 1999 through 2008) over the past ten years, and as a maturing utility, customer additions are fluctuating with the housing market.

This is consistent with the characteristics discussed in BCUC IR 1.19.1.1 that are associated with a mature or maturing utility.

19.1.3 Has TGI included changes in housing mix and changes in the conservation culture as a business risk component? If yes, please comment if the Commission should re-evaluate the business risk of TGVI and TGW relative to that of TGI.

Response:

Yes, TGI has included changes in housing mix and also changes in the conservation culture as a business risk component. Both of those factors influence the demand for natural gas, both are prevalent throughout the province, and therefore those factors add to the risk of all the Terasen Utilities. The business risk of TGVI and TGW relative to that of TGI is still appropriate, and do not require re-evaluation at this time.

19.1.4 In TGI's view, is it acceptable that a "developing" distribution company receive higher allowed ROE merely because of its given 'developing' status? I.e., Enbridge Gas New Brunswick (x-ref: Appendix 3, CEA Report, p.21 Note G).

Response:

In TGI's view the granting of a higher ROE for a developing utility is acceptable since the awarding of a fair return is in part one that provides the utility in question an opportunity to earn a return consistent with those available to similar enterprises with comparable risks. A new or developing utility with a small customer base and large initial investment (and related high investment per customer) would face additional challenges and risks including that of failing to achieve customer attachment levels that allow it to become financially viable in the long run. TGVI's predecessor companies for instance had to be restructured with government support and gas cost subsidies through royalty revenues and interest free Federal and Provincial loans when the restructuring was conducted in 1995. It can take decades for a utility to fully mature and changing circumstances along the way can accelerate or delay that maturation process.

In TGVI's case, it was originally envisioned that gas fired electric generating facilities constructed in addition to the demand of the pulp mills on island would provide a stable underpinning for the growth and development of the natural gas distribution business in TGVI's service territory. Only one co-gen facility was ever constructed and the Vancouver Island Gas Joint Venture group of pulp mills' demand has decreased down to less than 25% of the contract demand levels at the start of the decade. This has delayed the development of TGVI into a strong viable LDC in the absence of continued government support and continues to warrant a higher return than the benchmark.

20.0 Reference: Exhibit B-1, Tab 1, p. 1 Business Risk on Declining Throughput

The Application states: "All else equal, if throughput levels decline for whatever reason, TGI business risk increases."

20.1 Please confirm if there is a deferral account for changes in TGI throughput by customer group. Please provide details.

Response:

There is no deferral account for variations between forecast and actual thoughput for the industrial customer groups of TGI. There is a deferral account for variations between forecast and actual volumes due to use rate variations for Residential and Commercial customer classes, but there is no deferral account for changes in volumes resulting from variations in the forecasted number of customers.

The Revenue Stabilization Adjustment Mechanism ("RSAM"), originally approved by Commission Order No. G-59-94, is a mechanism that stabilizes the Company's delivery margin revenue from the Residential and Commercial customer classes (Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X and 23). The RSAM enables the Company to record delivery margin revenue for these customer classes based on the forecast use per customer for each rate class that was used in establishing rates. If weather or other factors result in the customer use varying from forecast, an entry is made to the RSAM account that adjusts revenue collected from customer rates from actual use to what customers would have paid based on forecast use. If actual use is less than forecast, the RSAM deferral account is charged for the variance in use times the delivery rate and the RSAM revenue is credited. Conversely, if actual use is greater than forecast, the RSAM deferral account is credited and the RSAM revenue is decreased. RSAM account balances are recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. Under the RSAM, if actual thoughput is lower than forecast for residential and commercial customers, due to use rate variances, the result will be, all else equal, an increase to those customers rates over the following three years thereby reducing the competitiveness of natural gas to alternatives.

The RSAM does not reduce risks associated with longer-term reductions in consumption, which longer-term risks are a significant aspect of the Company's business risk.

20.2 Please comment on how the earnings would differ from approved revenue requirement if the revenue collected and/or costs deferred satisfy the revenue requirement.

Response:

Where revenues realized or costs incurred differ from the approved amounts, and there is no associated deferral mechanism, earnings would also differ from the approved amount. The amount that earnings would vary by would depend on whether the item was taxable or not, and whether there was a sharing mechanism in place.

The pre-amble to this series of questions relates to TGI's assertion that declining throughput levels lead to increased business risk because the Terasen Utilities revenue requirements are primarily collected based on volumetric rates and as throughput levels drop, volumetric rates must increase leading to declining competitiveness and affordability for our customers.

As long as revenues collected satisfy the revenue requirement, the earnings forecast in the revenue requirement should be achieved for that period. When the revenue requirement is satisfied by costs being deferred for future recovery, there is uncertainty that they will be fully recoverable in the future. This can be the case even when the Commission grants an order that they will be allowed in the setting of future rates if such rates are not affordable leading to further reductions in demand, and is the case when expenditures are capitalized.

The existence of deferral accounts for core sales customers provides short-term protection for changes in use per customer for rate classes 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X and 23. The Company remains at risk for actual number of customers in these rate classes as well as all other customer classes leading to earnings variances in short term and competitive challenges in the longer term.

20.3 All else equal, if throughput levels increase for whatever reason, how would the earnings differ from the approved revenue requirement? Please explain. Does this depend on whether the change in throughput was included in ratemaking?

Response:

The level of business risk that TGI experiences as it relates to throughput is symmetrical; that is, in absolute dollars an increase in throughput within a customer class has the same impact as a decrease in throughput within the same customer class.

If throughput levels increase for the Residential and Commercial customer classes, and the increase is due to an increase in the use rate from the approved amount, earnings would not differ from that approved in the revenue requirement, since differences in the use rate would be captured in the RSAM deferral account, and returned to customers over the following three year period. Likewise, If throughput levels decrease for the Residential and Commercial customer classes, and the decrease is due to an decrease in the use rate from the approved amount, earnings would not differ from that approved in the revenue requirement, since differences in the use rate would be captured in the RSAM deferral account, and returned to customers over the following three year period. If throughput levels increase or decrease for other reasons, then earnings would be higher or lower than approved as described in the next two paragraphs.

If throughput levels increase for Residential and Commercial customers for reasons other than an increase in the use rate, of if throughput levels increase for any other customer class than Residential or Commercial:

- Under the 2003 to 2009 PBR, earnings would be higher than approved by one-half of the volume difference multiplied by the after-tax delivery rate.
- Under the proposed 2010 and 2011 Revenue Requirement Application, earnings would be higher than approved by the volume difference multiplied by the after-tax delivery rate.

If throughput levels decrease for Residential and Commercial customers for reasons other than an decrease in the use rate, of if throughput levels decrease for any other customer class than Residential or Commercial:

- Under the 2003 to 2009 PBR, earnings would be lower than approved by one-half of the volume difference multiplied by the after-tax delivery rate.
- Under the proposed 2010 and 2011 Revenue Requirement Application, earnings would be lower than approved by the volume difference multiplied by the after-tax delivery rate.

21.0 Reference: Exhibit B-1, Tab 1, pp. 1 and 34 Natural Gas vs. Electricity

TGI states that, "All else equal, if throughput levels decline for whatever reason, TGI business risk increases."

21.1 Is this statement true for the circumstances of TGI where the utility has a strong margin against other fuel options? i.e., the BC Hydro Tier 2 RIB rate, RSAM deferral account, no cost of gas risk through a deferral account, and that TGI earns its return based on rate base and rate base additions.

Response:

Yes. The statement is true when "All else equal, if throughput levels decline for whatever reason, TGI business risk increases." Where TGI has a competitive price advantage against other fuel options, declines in throughput will lead to higher unit costs and reduced competitive margin against those fuels. It is also true for each of the examples sited which will be discussed below.

In the case of the Tier 2 RIB rate, the only TGI customer rate classes that compete against this rate are residential 1, 1B, and 1U. Declining throughput will lead to lower revenue forecast which will force the company to increase delivery rates for all customers including these rate classes. Therefore the statement is true in this case.

The RSAM deferral account does not affect the rate competitiveness of TGI when throughput declines, it provides an opportunity in the short-term to recover margin related to use per customer variances in future rates. If the variances are due to declining throughput, it has the effect of putting further upward pressure on future rates leading to declining competitiveness – thus the statement remains true for this example sited in the question.

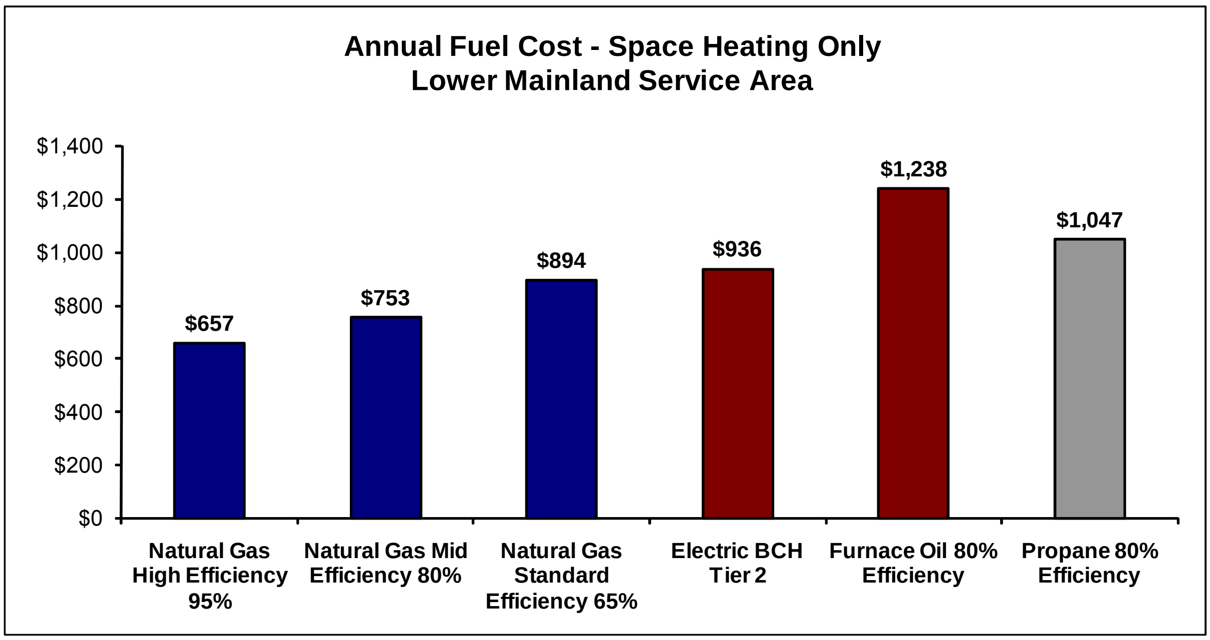
In the case of the gas cost deferral account, the deferral mechanism captures variances of gas costs for sales customers from that forecast and either refunds them or collects them in the following 12 months from the sales customers. The gas cost deferral account has no bearing on delivery rates so does not mitigate the impacts of declining throughput on delivery rates.

Finally, as indicated in the question, TGI's revenue requirement is set to recover its costs of service including a provision for an allowed return on its rate base. TGI collects its revenue requirement through a combination of monthly variable charges and volumetric delivery, midstream and gas cost charges. When throughput volumes decline, revenue variances not subject to deferral treatment result in lower revenues and earnings. Revenues subject to deferral mechanisms are built into future revenue requirements and the declining throughput built into future volume forecasts leading to increased delivery rates and declining competitiveness.

Therefore in all cases, declining throughput levels, all else being equal, lead to increased business risk.

21.2 Please provide a residential cost of heat comparison for natural gas, BC Hydro Tier 2 RIB rate, propane and home heating oil as at July 1, 2009. Please make explicit the assumptions used in the comparison.

Response:



Assumptions:
Terasen Gas rate includes the basic charge.
Typical space heating consumption of 58 GJs, based on a Mid Efficiency Furnace (80%)
Electric amount does not include basic charge since a household already pays the basic electric charge for non-heating uses.
Furnace Oil and Propane prices are based on the MJ Ervin and Associates Weekly Pump Price Survey - Canada dated July 7, 2009
Natural gas, furnace oil and propane rates are inclusive the applicable Carbon Tax effective July 1, 2009
Conversions:
1 GJ = 39.4 Litres of Propane
1 GJ = 25.8 Litres of Furnace Oil
1 GJ = 277.78 Kilowatt Hours

21.3 Please provide TGI's peak day supply forecasts for the last 10 years and a forecast for 2009 and 2010.

Response:

The following table illustrates the peak day demand forecasts over the past ten years, and also a forecast for 2009 and 2010.

	1999	**2000**	**2001**	**2002**	**2003**	**2004**
Peak Day Demand (TJ)	1,291	1,305	1,305	1,245	1,256	1,256

	2005	**2006**	**2007**	**2008**	**2009**	**2010**
Peak Day Demand (TJ)	1,256	1,278	1,275	1,279	1,274	1,282

Peak day demand has remained relatively stable over the period 1999 through 2008, and is expected to remain so over the next two years. Significant reductions were seen in 2002, likely in response to efficiency improvements that occurred while commodity prices increased significantly (and became more volatile) during the California energy crisis. Since 2002, peak day demand has shown only moderate growth (0.4% annually, on average), reflective of an increasing residential customer base (relative to the commercial and industrial customer base). Therefore, despite declining annual throughput, the stable (or moderately increasing) peak day demand will lead to a need for capacity that in large remains unused, thereby increasing risk associated with the company's ability to recover costs associated with maintaining that capacity.

21.4 Please provide TGI's capital expenditures for the last 10 years and forecasts for 2009 and 2010, broken out between base capital and CPCNs.

Response:

Below is a summary of TGI's capital expenditures for the last 10 years and forecasts for 2009 and 2010.

TGI Capital Expenditures ($ millions)

	1999 Actual	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Proposed
Category A												
Mains	5.7	5.9	4.6	4.6	4.2	5.3	7.4	8.1	8.1	11.0	8.9	8.3
Services	10.4	9.3	8.4	9.6	10.1	13.3	14.6	16.4	17.1	18.0	15.0	13.8
New Meters & Meters Recalled	15.5	14.7	13.7	13.4	17.5	15.4	15.3	16.2	13.7	14.9	14.0	19.7
Total Category A	**31.6**	**29.9**	**26.7**	**27.6**	**31.8**	**34.0**	**37.3**	**40.7**	**38.9**	**43.9**	**37.9**	**41.8**
Category B												
Transmission Plant	10.6	9.2	8.6	10.6	11.4	7.1	5.6	8.7	5.1	13.3	11.3	12.2
Distribution Plant	12.8	19.0	8.9	10.4	13.8	11.0	10.2	9.7	10.4	8.1	8.7	8.4
Total Category B	**23.4**	**28.2**	**17.5**	**21.0**	**25.2**	**18.1**	**15.8**	**18.4**	**15.4**	**21.4**	**20.0**	**20.6**
Category C												
IT	17.5	17.8	18.6	13.9	10.3	7.3	10.6	7.8	4.2	10.5	16.0	18.0
Non-IT	10.0	12.6	9.3	10.1	13.1	10.9	12.0	16.6	14.7	14.2	14.9	16.8
Total Category C	**27.5**	**30.4**	**27.9**	**24.0**	**23.4**	**18.3**	**22.6**	**24.5**	**18.8**	**24.7**	**30.9**	**34.8**
Total Base Capital	**82.5**	**88.5**	**72.1**	**72.6**	**80.4**	**70.4**	**75.7**	**83.6**	**73.2**	**90.0**	**88.8**	**97.2**
Figures exclude AFUDC and Capitalized Overheads												
CPCN	0.7	6.4	3.6	4.1	17.2	5.4	4.5	5.5	18.2	14.6	33.2	50.7

22.0 Reference: Exhibit B-1, Tab 1 p. 2 Competitiveness

TGI states that "Natural gas no longer enjoys a substantial operating cost advantage over electricity." However the Figures on pages 21 through 23 seem to indicate that natural gas is enjoying its largest margin in 10 years against BC Hydro Tier 2 rate.

22.1 Please reconcile the statement with the Figures.

Response:

Before responding directly to the question some background and clarification is needed. Figure 3.1.1 is a comparison of the total natural gas consumed by an average residential customer (95 GJ), not just the energy used in space heating applications. With the recent establishment of the BC Hydro RIB structure the actual operating cost difference between a natural gas home and an electricity home with the same applications has been complicated. To determine this operating cost difference one would need to look at the specific use pattern of the dwelling related to its total natural gas consumption and superimpose this on their existing electricity use to determine the appropriate electrical rate to use in the comparison. Terasen Gas would agree that in most cases for single family homes the BC Hydro RIB Step 2 rate is a reasonable comparison for space heating applications. The RIB Step 2 rate, however, is not necessarily a good comparison for the space heating requirements of a townhouse, condo or apartment. Much of the space heating energy consumption from these types of dwellings may come from the RIB Step 1 rate. Given this backdrop Terasen Gas addresses the question.

As stated in the Business Risk section of the Application (Tab 1, page 18), the annual operating cost of advantage of natural gas compared to electricity in B.C. from 1998 to 2008, has declined from 63% to 18%. This operating cost decline has had an impact on Terasen Gas' competitive position relative to electricity. An operating cost advantage is needed for natural gas to pay for the difference in capital costs to provide space heating capability in a natural gas home versus an electrical heated home.

With the establishment of the BC Hydro RIB rate in October 1, 2008 and the recent decline in the actual and forecasted natural gas commodity prices, the short term competitive position of natural gas has improved.

However, this current operating cost advantage (as outlined in Figures 3.1.1 comparing the Terasen Gas April/2009 rates against the BC Hydro Step 2 rate) may decline with an expected increase in natural gas commodity prices from the current natural gas prices that are used in setting Terasen Gas commodity rates for April/2009 ($5.966 Cdn/GJ). Natural gas prices are forecast to rise from current levels as outlined in the table below.

AECO (Cdn$/GJ) Historical and Forward (Forecast) Month Prices

	Year	Averages	
Actual	2004	$	6.44
	2005	$	8.04
	2006	$	6.62
	2007	$	6.26
	2008	$	7.70
	2009	$	4.16
Forecast	2010	$	5.80
as of July 1, 2009	2011	$	6.76
	2012	$	7.08
	2013	$	7.27

Note: 2009 prices includes actuals for Jan-June ($4.40 Cdn/GJ) and forecasted prices for July-Dec ($3.91 Cdn/GJ)

The reason for the expected increase in natural gas prices is related to the future recovery of the US and Canadian economies, which has the potential to change the current supply/demand picture for natural gas. Also, effective July 1, 2009 the B.C. carbon tax increases from its current levels of $.50 Cdn/GJ to $.75 Cdn/GJ and this tax will continue to increase through 2012 to $1.50 Cdn/GJ.

There are other factors beyond operating costs (as displayed in Figure 3.1.1) that have an impact on the competitive position of natural gas as compared to electricity over the long term. These include: differences in upfront capital costs for a natural gas space heated home versus an electrical heated home and changing customer perceptions towards natural gas. These factors are discussed below.

On page 30-31 of the Business Risks section (Tab 1 of the Application), Terasen Gas outlines why an operating cost advantage is need for a home heated with natural gas compared to one heated by electricity. It is clear from Figure 3.1.1 that since January 1, 2001 through January 2009, natural gas has not experienced the operating cost advantage it needs to make natural gas the economical choice for customer to meet their space heating requirements. Further, Figure 3.1.1 is calculated on total energy use in the home not just the operating cost advantage related to space heating. This conclusion is further supported by the BC Hydro CPR 2007, that states:

> *"No fuel switching measures were achievable. In other words, the measure payback period either exceeds the life of the measure or the measure never pays back the original investment."*[12]

[12] BC Hydro Conservation Potential Review 2007, Fuel Switching: Residential Sector, November 20, 2007, Page 112, Achievable Potential is defined: The portion of savings identified in the Economic Potential that could realistically be achieved within the study period through government and utility-led interventions and programs given institutional, economic and market barriers.

Finally, the GHG reduction targets, the Carbon Tax, the frequent public discussion of the role of GHGs in climate change and potential future increases and volatility in natural gas prices have changed customers' perception towards natural gas in B.C. This is supported by statements made by customer groups such as BCOAPOs which state:

> *"BCOAPO recognizes that Terasen's current rate compares favorably against BC Hydro's trailing residential rate. Right now, customers choosing natural gas for space and water heating are seeing a definite financial benefit as compared to their electricity-using counterparts. However, given the volatile natural gas prices, this could change at any time and customers would again find themselves in a situation where natural gas is no longer even the most economic choice*."[13]

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[13] BCOAPO, Final Argument in BC Hydro 2008 LTAP, dated April 27, 2009, page 8

23.0 Reference: Exhibit B-1, Tab 1, p. 2 Business Risk

23.1 Please provide any cost increases to the Terasen Utilities as a result of the aboriginal rights effects on operational and regulatory complexities. Have any related costs been disallowed in a revenue requirement application?

Response:

The Terasen Utilities have been experiencing growth in dialogue with First Nations regarding all aspects of the company's operations, and expect that there will continue to be an increase in efforts associated with this activity. First Nations have increased their requests for negotiated agreements regarding access to existing rights of way. First Nations are also seeking consultation agreements with Terasen to assess impacts on rights and interest with a desire to develop acceptable mitigation and accommodation measures. A recent development has been the Terasen Utilities' development of ongoing Aboriginal participation strategies in co-operation with Aboriginal organizations.

During the PBR period Terasen Gas has not had any costs relating to First Nations disallowed.

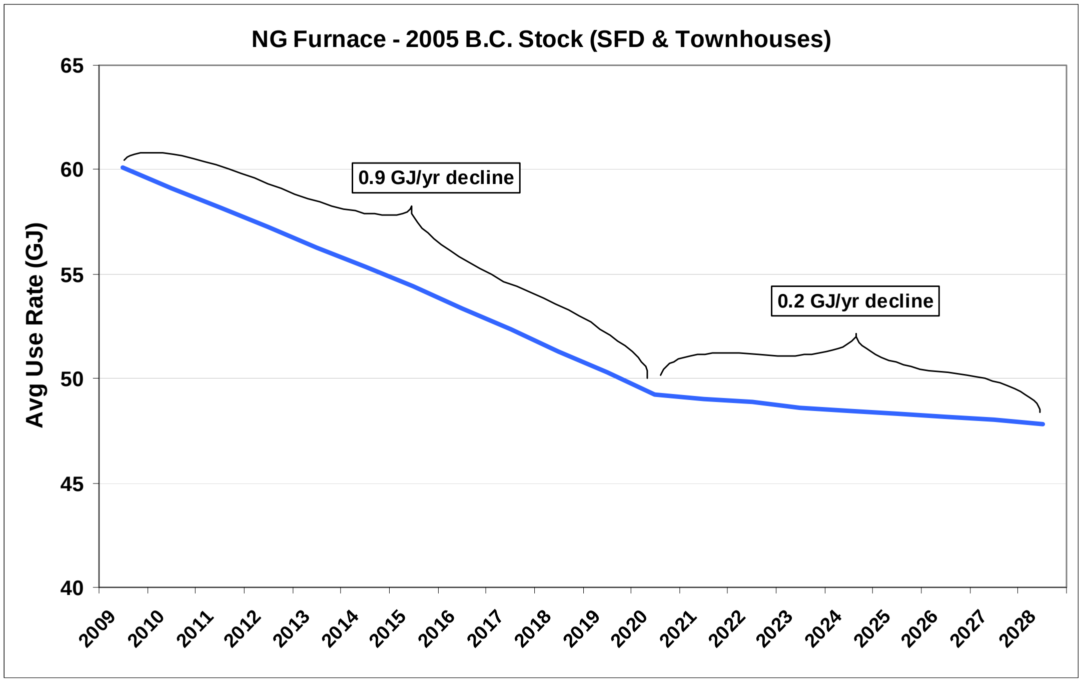
23.2 Do Terasen Utilities agree that a multi family dwelling development (i.e., high-rise) that have replaced single family dwellings in a re-zoned lot could result in higher throughput simply because of an increased number in dwellings?

Response:

TGI does agree that a multi-family development that replaces single family dwellings in a re-zoned lot ***could*** result in higher throughput simply because of an increased number of dwellings.

However, given that TGI's capture rate is much lower for multi-family dwellings, as single family dwellings are replaced by multi-family dwellings, the throughput levels do not necessarily increase. And that is because a portion of those multi-family dwellings do not end up becoming Terasen Gas customers.

More generally, there are many factors that are contributing to the overall decline in residential throughput, including not only the shift towards more multi-family dwellings in the housing mix, but also the continued efforts of our existing customers to improve efficiencies, and the increasing availability of alternative energies. These are a result of increased awareness around energy usage, technological improvements, changes to standards regulating furnace efficiencies, and also the public perception around natural gas being influenced by climate change policy. And these factors together have contributed to the approximate 12% decline (see TGI's response to BCUC IR#1 Q3.1) in total throughput since 1999, and more importantly are expected to continue influencing throughput downward over the foreseeable future. As the declining residential throughput is primarily attributed to retrofit activity, the following graph illustrates not only the estimated impact of retrofit activity, but also illustrates this factor is a long-term issue.



23.2.1 Assume a city block of 20 single family dwellings have been replaced by two 15-story high-rises with four units per floor. Please provide calculation of the volume of natural gas consumption by the new multi-family dwellings and compare it to the total volume of natural gas consumption by the single family dwellings that they replace.

Response:

To better illustrate the impact of multi-family dwellings replacing single family dwellings, TGI is assuming there are ten city blocks with each having twenty single family dwellings on them. Those ten city blocks are then assumed to be re-zoned and the single family dwellings replaced by two fifteen-storey high-rises with four units per floor on each block. The assumptions regarding annual average use per customer are stated in response to BCUC IR 1.23.2.1.1.

The following provides an estimate of the annual consumption for those ten city blocks, first with the single family dwellings on them, and then with the high-rises on them. For simplicity, TGI is assuming a capture rate for multi-family dwellings of 20%.

1) Ten city blocks with twenty single family dwellings on each block:

   Average annual consumption per single family dwelling = 94 GJ

   Total estimated throughput = 10 city blocks X 20 dwellings/block X 94 GJ/year

   = 10 X 20 X 94

   = 18,800 GJ per year

2) Ten city blocks with two fifteen-story high-rises on each block, with four units per floor:

   Average annual consumption per unit in this high-rise = 59 GJ

   Total estimated throughput = 20% capture rate X 10 city blocks X 2 high-rises/city block X 15 storeys/high-rise X 4 units/floor X 59 GJ/year

   = .20 X 10 X 2 X 15 X 4 X 59

   = 14,160 GJ

Therefore, the impact of multi-family dwellings replacing single family dwellings under the above circumstances would be a 25% decline (or 4,640 GJ per year) in total annual throughput.

23.2.1.1 Please make explicit your assumptions on use per account by dwelling type.

Response:

TGI is assuming that the average annual consumption (under normal weather conditions) for a single family dwelling is 94 GJ per year, which includes all natural gas end uses within that dwelling. The estimated annual average consumption for an average unit within a high-rise (vertical subdivision) is 24 GJ per year, and includes all natural gas end uses other than make up air (MUA) and domestic hot water (DHW). Those assumptions are derived from preliminary figures obtained from the 2008 Residential End Use Study (2008 REUS). Since both MUA and DHW, for high-rises, are typically provided to each unit through a single meter (which would be classified as a commercial customer), average consumption for these uses were outside the scope of the 2008 REUS. TGI assumes the average annual consumption per unit for MUA and DWH is 35 GJ per year. This assumption is based on informal discussions with industry experts.

Therefore, TGI assumes the average annual consumption for a single family to be 94 GJ per year, and for each unit within a high-rise to be 59 GJ per year. As TGI's response to BCUC IR#1 Q23.2 indicates, as the shift towards more multi-family dwellings in the housing mix continues, the result is downward pressure on average residential use per customer.

23.2.1.2 Does TGI agree with the increased number of dwelling units assumptions provided in this IR?

Response:

Although TGI agrees that the increased number of dwelling units assumptions appear reasonable, as per TGI's response to BCUC IR#1 Q23.2.1, the ongoing shift towards more multi-family dwellings in the housing mix will place downward pressure on throughput levels, not increase it.

24.0 Reference: Exhibit B-1, Tab 1 p. 4 Conservation and Efficiency Policies

The Application states that many of the 2007 Energy Plan policies will have the ultimate effect of reducing throughput on the TGI system.

24.1 Please provide, in tabular format, the throughput, total and by customer group, for TGI from 1994 to the present, as well as the forecasts for the next five years.

Response:

The following table illustrates the total throughput in PJs for residential, commercial, firm sales, and industrial and transportation customers, with actual results from 1994 through 2008, and then a projection for 2009 and forecast for 2010 through 2014.

(in PJs)

	1994	**1995**	**1996**	**1997**	**1998**
Residential	70.9	73.9	74.1	75.7	76.7
Commercial	49.3	51.1	50.6	51.1	47.9
Firm Sales	3.9	4.6	4.9	5.9	7.2
Industrial & Transportation	121.5	131.9	95.6	105.3	117.2
Total	**245.6**	**261.5**	**225.2**	**238.0**	**249.0**

	1999	**2000**	**2001**	**2002**	**2003**
Residential	77.8	75.4	68.4	72.6	72.6
Commercial	51.5	47.3	43.9	44.3	45.3
Firm Sales	9.6	10.9	8.9	6.9	6.1
Industrial & Transportation	98.6	110.1	125.2	96.4	94.8
Total	**237.5**	**243.7**	**246.4**	**220.2**	**218.8**

	2004	**2005**	**2006**	**2007**	**2008**
Residential	72.0	69.3	70.0	70.6	68.8
Commercial	45.2	43.9	44.1	45.5	45.9
Firm Sales	5.3	4.7	4.1	3.8	3.5
Industrial & Transportation	97.5	94.8	90.9	95.0	91.3
Total	**220.0**	**212.7**	**209.1**	**214.9**	**209.5**

	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Residential	71.0	67.8	67.2	66.9	66.6	66.2
Commercial	47.5	47.3	47.9	48.6	49.3	49.9
Firm Sales	3.4	3.4	3.3	3.3	3.3	3.3
Industrial & Transportation	83.2	82.4	82.5	82.8	83.0	83.4
Total	**205.2**	**200.9**	**201.0**	**201.6**	**202.2**	**202.8**

Notes:
1. The residential sector includes TGI Rate 1 customers
2. The commercial sector includes TGI Rate 2, 3, and 23 customers
3. The firm sales sector includes TGI Rate 4, 5, and 6 customers
4. The industrial & transportation sector includes TGI Rate 7, 22, 25, 27 and also Centra and Burrard Thermal customers

As can be seen from the above table, total throughput remained relatively stable over the period 1994 through 2001, at which time a significant step change occurred (~10% decline) as a result of the increased volatility in commodity prices (during the California energy crisis). The next few years (until 2004) again remained relatively stable, but in 2005 another step change occurred as commodity prices once again increased (as a result of Hurricane Katrina). The declines seen since then, through 2008, have occurred for a number of reasons, including an increased focus on energy conservation by existing customers, a decline in the competitiveness of natural gas, and the fact that new customer attachments are not offsetting the declining energy demand from existing customers. Overall, Terasen has experienced declining volumes since 1999, and as the factors causing this decline are expected to continue impacting demand over the longer-term, there is increasing risk associated with our company's ability to recover its investment over the long term.

The projection for 2009 and forecast for 2010 & 2011 is from the recently filed 2009 TGI Revenue Requirement Application, and are based upon an analysis of the recent historical normalized actual results, trends in the market that are influencing the demand for natural gas (as discussed above), and also the economic outlook for BC. The longer-term forecast figures, for 2012 through 2014, are based upon the assumption that residential use per customer rates continue to decline, commercial use per customer rates remain stable, and industrial volumes also remain stable. Although today these assumptions are reasonable, there is increased uncertainty surrounding commercial and industrial volumes over the longer-term, as the impact of the BC Energy Plan (and programs/policies developed as a result of it) have not yet been seen. Therefore, it would be reasonable to assume there is down-side risk associated with the commercial and industrial volumes over the longer-term.

24.2 Please repeat the above for TGVI and TGW.

Response:

The following table illustrates the annual normalized throughput in TJs for residential, commercial and transportation customers of TGVI over the period 1997 through 2008, a projection for 2009 and forecast for 2010 through 2014. Normalized volumes from 1994-1996 are not available at this time.

(in TJs)

	1997	1998	1999	2000	2001	2002
Residential	3,016	3,383	3,669	3,854	3,748	3,872
Commercial	6,374	6,559	6,953	6,956	6,951	7,117
Transportation	16,511	14,685	16,384	16,404	16,289	22,399
Total	**25,901**	**24,627**	**37,856**	**38,412**	**38,777**	**39,545**

	2003	2004	2005	2006	2007	2008
Residential	4,034	4,020	4,259	4,602	4,575	4,696
Commercial	7,310	7,237	7,412	7,341	7,491	7,345
Transportation	21,169	21,536	22,146	16,334	23,302	22,342
Total	**32,513**	**32,793**	**33,817**	**28,277**	**35,368**	**34,383**

	2009	2010	2011	2012	2013	2014
Residential	4,859	4,892	5,015	5,143	5,274	5,408
Commercial	7,405	7,349	7,418	7,511	7,605	7,700
Transportation	22,946	22,309	22,017	22,336	22,350	22,365
Total	**35,210**	**34,550**	**34,450**	**34,990**	**35,229**	**35,473**

Notes:

1. Residential includes RGS customers
2. Commercial includes SC1, SC2, LC1, LC2, LC3, AGS, HLF, and ILF customers
3. Transportation includes ICP, JV, and also TG Squamish customers

As can be seen from the above table, annual throughput has grown significantly on TGVI's system over the period 1997 through 2008 (a 33% increase, or 2.6% annually). Looking at the individual customer segments, residential throughput has grown 4.1% per year, commercial throughput has grown by 1.3% per year, and transportation throughput has grown by 2.8% per year. This is consistent with TGVI being an immature utility. And given this, coupled with there being fewer opportunities for efficiency improvements, it is not surprising that the forecast of throughput for TGVI is for growth over the foreseeable future.

The following table illustrates the annual normalized throughput in TJs for residential and commercial customers of TGW over the period 1997 through 2008, a projection for 2009 and forecast for 2010 through 2014. Normalized volumes from 1994-1996 are not available at this time.

(in TJs)

	1997	1998	1999	2000	2001	2002
Residential	94.3	107.5	126.0	141.6	145.4	156.3
Commercial	389.3	441.2	480.7	549.8	541.8	534.6
Total	**483.6**	**548.7**	**606.7**	**691.4**	**687.2**	**690.9**

	2003	2004	2005	2006	2007	2008
Residential	177.8	168.0	189.3	175.3	198.5	189.6
Commercial	546.9	556.2	579.7	558.4	543.6	519.8
Total	**724.7**	**724.2**	**769.0**	**733.7**	**742.1**	**709.4**

	2009	2010	2011	2012	2013	2014
Residential	206.5	200.8	203.5	205.4	207.4	209.9
Commercial	510.7	524.4	526.3	529.6	532.2	535.5
Total	**717.2**	**725.2**	**729.9**	**735.0**	**739.6**	**745.4**

Notes:

1. Residential includes SCS1/2 Residential customers
2. Commercial includes SCS1/1 Commercial, LC1, LC2, and LC3 customers

Annual throughput for TGW, as illustrated above, has also grown significantly over the period 1997 through 2008 (a 47% increase, or 3.5% annually). This growth has been driven by the residential customer segment, where throughput has more than doubled over this period, averaging 6.6% growth per year. The commercial segment has also grown significantly (2.7% per year), but not quite at the rate the residential customer segment has experienced. The growth in throughput for TGW is also consistent with that for an immature utility, with the declines from 2006 through 2007 attributed to the large commercial customer segment, where energy management systems have been installed in more recent years, causing significant reductions in volumes. Other than that, growth has been fairly steady for the remaining customer classes.

24.3 Please describe to what extent the future increase/decrease is caused by the effects of the provincial government's Energy Plan.

Response:

The provincial government's Energy Plan has set targets for conservation and energy efficiency which are aimed at reducing the overall energy demand "at work" for residential and commercial buildings, and also to reduce average energy demand per home. The Energy Plan also states the government will work closely with BC Hydro and other utilities to research, develop, and implement best practices in conservation and energy efficiency, and also to increase public awareness. Changes to building codes and also revised standards regarding minimum efficiency levels for new appliances are an indication the government is focussed on having standards in place that will impact overall energy demand. However, given the provincial government's Energy Plan does not include specific targets for natural gas, it s very difficult to develop estimates regarding the extent to which increases/decreases in the demand for natural gas can be attributed to the effects of the Energy Plan. It is, however, reasonable to assume that the Energy Plan will influence not only consumption behaviours, but also the type of appliances available for use (with respect to efficiency levels), and ultimately contribute towards the declining throughput levels being experienced by TGI. The potential efficiency gains are further seen in the figure below, which illustrates the difference between an older, low-efficient home and a new, high-efficient home.

Older Low Efficient Home in Vancouver

- One storey building with basement
- 2,500 square foot older home
- Below average insulation in ceiling and walls
- Single pane windows (USI 6.7 - Single)
- Average temperature 19 degrees Celsius
- Air tightness: 6.0 ACH (tested at 50 Pascals)
- Standard efficient furnace, AFUE of 71%

Space Heating Energy = 137.6 GJ/yr

New High Efficient Home in Vancouver

- One storey building with basement
- 2,500 square foot new home (code compliant)
- Above average insulation in ceiling and walls
- Energy Star windows (USI 2.0)
- Average temperature 21 degrees Celsius
- Air tightness: 5.4 ACH (tested at 50 Pascals)
- High efficiency condensing furnace, AFUE of 90%

Space Heating Energy = 50.7 GJ/yr

Source: Modelled through Natural Resources Canada's HOT 2000 software

The newer, high-efficient home reflects changes to building codes and also furnace regulations. When compared to the older, low-efficient home, it can be seen that there is a significant potential in terms of efficiency gains.

24.4 Reference: Exhibit B-1, Tab 1, pp. 4, 5 Recovery of Investment

"Over the long term, a decrease in throughput volume leads to high unit delivery costs for customers, which makes natural gas less competitive, which in turn hinders TGI's ability to recover its investments."

24.4.1 Please provide examples, if any, of where a TGI revenue requirement process has disallowed recovery of investment due to decreases in throughput volume.

<u>Response:</u>

The premise of the quotation from the Application is that declining throughput leads to rate increases. Declining use per customer was the single most significant factor putting upward pressure on customer delivery rates during the 2004-2009 PBR settlement period. Terasen is not aware of disallowances of investment due to decreases in throughput volume as part of a revenue requirement process.

25.0 Reference: Exhibit B-1, Tab 1 pp. 5, 10 GHG Reduction Targets

It is expected that the operating emissions of TGI and TGVI and the emissions of their customers from natural gas consumption make up approximately 17 per cent of BC total emissions for 2006 (page 5).

As natural gas is a fossil fuel, and given the aggressive provincial GHG reduction targets, the BC Carbon Tax translates into an increase in the business risk profile for TGI (page 10).

25.1 Do Terasen Utilities believe that the government policies and strategies to reduce GHG (i.e., Greenhouse Gas Reduction Targets Act, Carbon Tax Act, Western Climate Initiative, etc.) are unique to natural gas utilities in B.C.? Please explain your answer.

Response:

Yes.

BC's aggressive GHG reduction targets and being the first jurisdiction in North America with a carbon tax tied directly to the consumption of fossil fuels, has resulted in changing customer perception towards natural gas consumption in B.C. This reality is further enhanced by B.C. vast supply of renewable "clean" electricity. These facts place natural gas utilities operating in B.C. at greater risk than other natural gas utilities across North America. Electricity generation in most other jurisdictions in North America includes much higher percentages of gas and coal fired generation than in BC. In those jurisdictions direct use of natural gas in space and water heating applications provides an opportunity of displacing fossil fuel fired electricity generation and thereby reducing GHG emissions. Even natural gas fired generation displacing coal fired generation provides a large GHG reduction benefit. Natural gas is seen as part of the solution in these jurisdictions.

As an example on how these GHG policies have changed the thinking of how energy should be used in B.C., Terasen Gas points to the change in BC Hydro's position regarding using natural gas in such applications as space and water heating. This position change is outlined on pages 8 and 9 of the Business Risks section of the Application.

Further in the recent BC Hydro 2008 LTAP, the following statement is made:

"MS. VAN RUYVEN: A: So if you have a house heated by gas, all of those incentives in the LiveSmart program were meant to get in high-efficiency gas furnaces. So make the envelope of the building that you are in the most efficient it can be, regardless of fuel choice. So that's number one. And then to the conversations we've had with government, overwhelmingly these things that they're trying to do are reducing greenhouse gases in British Columbia. So you can see switching from diesel to cleaner gas is a positive thing, whether it's the transportation sector or the utility sector. So you can see as you read through these that I think an overwhelming desire is to reach that

legislated 32 percent reduction in greenhouse gases. And in the discussions that I've been in with government and with Terasen, they've been very clear that they do not want to put forward a policy that actually sees B.C. Hydro incenting increases in greenhouses gases in British Columbia. That goes against the legislated greenhouse gas reduction that they are very much trying to put lots of programs in place to get at.

MR. GHIKAS: Q: Ms. Van Ruyven, the expressed policy that we have is in the Energy Plan, and I believe that B.C. Hydro has made it clear that that be ignored at everyone's peril. Is that fair to say?

MS. VAN RUYVEN: A: Well, I was just stating a legislated requirement for greenhouse gas reductions in British Columbia, and I believe in the conversations I have had with government is they support programs that get at actual reductions of greenhouse gases in British Columbia.

MR. GHIKAS: Q: Okay. We're going to come to that in a moment, but from what I understand you saying is that the greenhouse gas reduction targets for provincial GHGs trump all other policy.

MS. VAN RUYVEN: A: That's what I'm saying. They trump, they trump a –"[14].

It is clear from these statements that government policy and strategies are having an impact on how energy should be used and consumed in B.C. given these GHG reduction targets.

In most jurisdictions across North America, the direct use of natural gas consumption is recognized as a way of helping to reduce GHG emissions. As an example, two Pacific Northwest Utilities (Avista Corp. and Puget Sound Energy) have energy efficient programs in place that promote the direct use of natural gas for such applications as space and water heating. This is a better solution from a GHG reduction point of view and cost impact to the electrical customers than using electricity to serve these direct use applications. Please refer to Attachment 25.1 for details on the Avista and Puget program. These programs highlight that energy use and solutions to reduce GHG can be different from jurisdiction to jurisdiction.

Given BC's ability to produce renewable electricity and given the strong mandate by the B.C. provincial government on reducing GHG emission, some customer groups and competitors believe that B.C.-produced clean electricity should be used at a greater rate in applications that historically have been filled by natural gas, namely in such applications as space and water

[14] BC Hydro LTAP 2008, Transcript Volume 3, February 13, 2009 page 281-283

heating. These realities make the GHG reduction path forward unique in B.C. and increase the business risks of the B.C. natural gas utilities, including TGI.

25.2 Do utilities in other jurisdictions in Canada and the US face similar new regulation with respect to reducing GHG emissions? Do some of these utilities face additional costs and/or reduced earnings from cap-and-trade programs for example, electricity generation facilities in U.S. jurisdictions having to use 'offsets'?

Response:

Yes, it is expected in the coming years that utilities across Canada and US will face new regulations with respect to reducing GHG emissions. These regulations will have an impact on these utilities by mandating reduction targets or setting performance standards in producing and delivering energy to consumers. This will result in increased cost for the utilities to comply with these new regulations over time. However, what is unclear at the present time is what form these new regulations will take. Currently, there is overlap in proposals or policies already in place at both the federal and state/provincial government levels across both the US and Canada around setting GHG reduction policies. It is unclear how these policies will work together or if one common system for reducing GHG emissions across North America will be put in place. What is clear, is B.C. has already taking steps through such mechanism as the carbon tax that do impact the competitive position of business within B.C. versus other jurisdiction across North America. Purchasing offsets is just another mechanism to conform to the future regulation, which will represent a cost to the utility in providing service to customers.

An important difference in B.C. as compared to other parts of North America is the presence of major hydro-electric production and the very small amount of fossil fuel fired electric production in B.C. As discussed elsewhere, this distinguishes the competitive position of the Terasen Utilities from gas distribution utilities in most other parts of North America.

25.3 In Terasen Utilities' opinion, would financial implications be more significant among LDCs and electric utilities in the U.S. due to their emission levels, carbon intensity, carbon costs relative to earnings? Why or why not?

Response:

Terasen Utilities are uncertain of the impact carbon costs will have on electric utilities in the US and for that matter utilities as a whole, given the uncertainty around what the GHG regulations will entail across different jurisdictions. However, in jurisdictions that have high GHG intensity in their electricity generation electrical utilities may be as much or more affected than gas utilities by climate change and GHG emission reduction regulations. The competitive position of natural gas utilities in such jurisdictions will be improved as the policies and regulations are implemented. This is not the case in BC since electricity generation in the province has low GHG intensity.

The only thing that is known for sure is that there will be compliance costs related to GHG regulation in the future. The costs each utility will pay will be determined by the regulation that the company must comply with and the source of energy that the utility is producing or moving to customers. For example, currently in B.C. the carbon tax applies to all fossil fuel consumption within B.C. However, the imported power that is consumed by residents of B.C. is presently exempt from this carbon tax; even though, this electricity has more than likely been produced from a fossil fuel. This is an example, of how different regulation across jurisdictions and energy sources can favour one energy form versus another.

26.0 Reference: Exhibit B-1, Tab 1 p. 10 Business Risk

The Application states that the provincial carbon tax increases the business risks of TGI. By 2012, natural gas consumers in BC will be paying $1.50/GJ in carbon tax. The carbon tax beyond 2012 is unknown at the present time.

26.1 What would be the increases (in absolute amount and in percentage terms) in the natural gas bill for a typical customer (residential, commercial, industrial) as a result of carbon tax in 2011 and 2013?

Response:

Please refer to Attachment 26.1 for the increases in total annual bill and percentage burner-tip for typical Lower Mainland residential (Rate Schedule 1), commercial (Rate Schedule 3), and industrial (Rate Schedule 5) customers as a result of the carbon tax in 2011 and 2013.

The schedule reflects the currently enacted increases which will become effective each July 1 through 2012. While there has been no additional announced change beyond 2012 the schedule reflects the impact of the carbon tax of $30/tonne at July 1, 2012 for the full year in 2013.

26.2 What are TGI's expected demand elasticity's with respect to price or cross elasticity's with respect to alternative fuels for the various customer groups as a result of the increase in carbon tax?

Response:

TGI estimates demand elasticity with respect to price, but does not estimate the cross elasticity's with respect to alternative fuels. Historically, electricity rates have remained quite stable, and therefore calculating cross-price elasticity's would not result in meaningful results. TGI will continue to monitor this, and when it is deemed that cross price elasticity's are meaningful, they will be estimated. The cross-price elasticity with respect to alternative fuels other than electricity are also difficult to estimate, as consumption information is not readily available.

The demand elasticity with respect to price for residential customers is estimated to be approximately 21%, and for commercial customers is estimated to be approximately 17%. Given that, the increase in carbon tax is estimated to cause at most an approximate 0.5% reduction in demand for residential customers, and at most an approximate 0.4% reduction in demand for commercial customers each year until the carbon tax reaches $1.50 in 2012.

The demand elasticity with respect to price is estimated using historical consumption data that includes variability that is caused by a number of factors, including retrofit activity, changes in the housing mix, changes to building codes & standards, and also non-recurring events such as the California Energy crisis and Hurricane Katrina. These factors all introduce a certain amount of "noise" in the demand data, which diminish the strength of the relationship between strictly price and demand. It is for that reason that TGI assumes the demand elasticity with respect to price should be used to estimate the maximum change that will likely occur due to price fluctuations. Furthermore, when prices decline, TGI does not believe the demand elasticity with respect to price is valid at all, due to the fact that in most cases, actions that result in declining consumption levels are permanent (i.e. retrofitting appliances).

27.0 Reference: Exhibit B-1, Tab 1, p. 11 Carbon Tax

27.1 Are there plans for TGI to recover the cost of implementing the carbon tax? Have any costs incurred related to the carbon tax been disallowed for recovery?

Response:

Since the B.C. Carbon Tax was introduced starting July 1, of 2008, it has created increased costs pressures on the Company's that ultimately gets reflected in delivery rates to customers. Also, the tax increases the direct costs to consumer who use natural gas in their homes and businesses.

The costs to customers related to this tax come in two forms:

1) Direct taxation tied to customer consumption of natural gas

The Terasen Utilities collect the carbon tax on behalf of the provincial government and remit these taxes to government. These taxes are directly tied to the customer's amount of natural gas consumed. This places the Terasen Utilities at a competitive disadvantage with BC Hydro, whose imported electricity to serve domestic load is not taxed under the BC Carbon Tax Act.

2) Terasen Utilities own use emissions

On May 15, 2008, TGI filed a Carbon Tax and Provincial Tax Rate Treatment Application in response to the release the Carbon Tax Act. In addition to the cost of service impact incurred as a result of the consumption of fossil fuels for the operation of TGI's business, the Application also identified one time estimated software upgrade, tax consulting and legal fee costs of $0.3 million associated with the implementation of the Carbon Tax Act. As a result, the Company requested and received Commission approval through Order No. G-88-08 for deferral account treatment of these costs as an exogenous item, subject to a review of actual expenditures.

On a go forward basis, as part of the 2010-2011 Revenue Requirement Applications filed on June 15, 2009, TGI included cost of service impacts of the Carbon Tax on fuel used in vehicles, compressors and line heaters. It is within this Application that the Company plans to recover the cost of implementing the carbon tax on Company-use fuel for approximately $410 thousand for 2010 and $530 thousand for 2011, embedded in O&M, cost of gas, and capital.

28.0 Reference: Exhibit B-1, Tab 1, p. 13 Climate Action Recommendations

"All of the above recommendations have the intent of reducing fossil fuel use within homes and businesses, which by their nature threaten the Terasen franchise and increase business risk for TGI."

28.1 The quote references items which may occur in the future. Please provide an estimate of dollar impacts to the TGI revenue requirement for items which have already occurred.

Response:

TGI has increased marketing and related costs to meet the customer's changing energy needs as a consequence of the BC Energy Plan 2007. TGI has not specifically incurred cost to deal with recommendations from the Climate Action Team, given that these measures build on policy items that promote efficient use of energy. TGI anticipates that it may need increased funding to support the Climate Action Team recommendations if and when these recommendations become accepted by government.

While the current revenue requirement which is in place through 2009 is set by the TGI PBR agreement, this increase in O&M costs will result in fewer O&M cost savings being shared by the customer and shareholder. As noted in the TGI Revenue Requirement Application 2010-2011, "In more recent years, sales, account management and business development staff have been added to the Customer Solutions and Services group, and additional staff have been added to the Customer Care and Services group. The additions of these staff were to address and meet changing customer expectations".

Since 2007, the increases that can be attributed to changing customer needs in reaction to the 2007 BC Energy Policy items that impact O&M are projected to be $2.9 million.

Further, TGI and TGVI have applied and received approval for EEC expenditures for 2008-2010 to help promote the efficient use of energy by customers, a key cornerstone of government policy. The table below shows the breakdown of the amounts approved for the period.

	2008		2009		2010
	O & M	Deferral	O & M	Deferral (Forecast)	Deferral
TGI ('000s) Programs as per EEC	$ 1,740	$ 744	$ 1,624	$ 7,258	23,075
TGVI ('000s) Programs as per EEC	$ 452	$ -	$ 497	$ 1,379	$ 4,726

As part of the EEC approval, all dollar amounts are to be capitalized and amortized over a 10 year period. The resultant revenue requirement impacts of this financial treatment is to reduce O&M going forward and increase capital and associated return on rate base.

29.0 Reference: Exhibit B-1, Tab 1, pp. 14 to 15 Aboriginal Rights Effects on BC Utilities

29.1 Please provide any information regarding operational and regulatory complexity as well as risk of litigation currently faced by the Terasen Utilities with respect to aboriginal rights. Please provide any legal or regulatory liabilities faced by Terasen Utilities in recent years with respect to aboriginal liabilities.

Response:

The Companies provide service to customers on First Nations lands and maintains gas transmission and distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the government of British Columbia is underway, but the basis upon which settlements might be reached in the Companies' service areas is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as the Companies. However, there can be no certainty that the settlement process will not adversely affect the business of the Companies.

The Terasen Utilities manages any issues around Aboriginal rights by working with the band and the band's guidelines concerning land rights and use. Operationally, the Companies have front line contact points to address band concerns with regular communication and are proactively building and maintaining relationships with Aboriginal groups.

The Terasen Utilities are not currently subject to any litigation related to First Nations issues as significant effort is committed to successfully negotiating agreements. However, claims have been made with the suggestion that litigation might ensue on large projects currently underway or recently completed, and also with respect to facilities that have been in service for many years. In addition, the BC government has proposed new legislation which would recognize the existence of First Nations, with their own laws, governments and territories and title to land. It is not clear what effect this new legislation would have on the Companies, but it does create additional uncertainty and is likely to increase risk relating to land tenure and project execution.

In terms of regulatory liabilities, recent decisions of the BC Court of Appeal require an expanded role for the BCUC that suggests a more involved regulatory process may be required relating to First Nations consultation in applications before the BCUC, which will likely increase the cost and complexity of future regulatory applications.

29.2 Please specifically identify and show the changes from 2005 to present the aboriginal rights effects on investor-owned BC utilities. Were aboriginal rights effects on TGI an issue in the previous ROE Application (June 30, 2005)?

Response:

Aboriginal law is an evolving and complex discipline and requires diligent attention.

Although risks involving claims relating to aboriginal rights existed in 2005, those risks have significantly heightened over the last five years. There have been a number of significant changes to the law relating to Aboriginal rights and title since 2005 including those matters discussed in BCUC IR 29.1 above, as well as the 2007 BC Supreme Court case regarding the Tsilhqot'in Nation which have heightened the expectations of First Nations with respect to the extent of aboriginal title lands in BC, and which continue to refine the duty of consultation. The uncertainly in the law and potential risk associated with Aboriginal rights and title are reflected in the fact that the Companies have committed additional resources to both keep abreast of the current state of the law and to ensure that the Companies continue to conduct business in a manner that respects the social, economic and cultural interests and expectations of Aboriginal groups.

Aboriginal rights effects on the Companies were neither expressly mentioned in the previous ROE Application nor in the subsequent BCUC decision. However, the Companies' increased concern and attention to Aboriginal rights issues, and their potential effect on land tenure and project execution, is reflected in the current ROE Application as well as other recent applications before the BCUC.

30.0 Reference: Exhibit B-1, Tab 1 p. 24 Natural Gas Vs. Other Energy Source

TGI states that "Natural gas commodity pricing for consumers in BC is market based; in contrast a large percentage of the costs making up electricity rates are the low embedded costs of BC Hydro's Heritage generation facilities."

30.1 For residential sales, is it not the true that the relevant comparator is the BC Hydro Tier 2 which is a rate that resembles the cost of new generation?

Response:

The BC Hydro RIB Step 2 rate is a relevant comparator in many cases for residential sales but other factors such as the dwelling type and the additional upfront capital costs of piping, ducting and natural gas space and water heating equipment relative to comparable electrical equipment are also important considerations in the overall picture. Smaller dwellings such as townhouses and apartments use less energy for space and water heating requirements and are less likely to have space and water heating energy use coming from above the Step 2 consumption threshold. Also, the trends toward improved energy efficiency and smaller dwellings, as well as government policy and legislation promoting energy efficiency, suggest that over time a decreasing portion of the energy consumption for space and water heating will come from consumption over the Step 2 threshold, under the RIB rate structure as currently constituted.

In the case of new construction, and also in the case of end-of-life equipment replacement, capital cost differences between the gas-fired equipment and electricity based systems take on a larger prominence. In many cases it is the builders and developers that make the decision on the heating systems to install and base their decision on simple economic comparisons and their expectation of whether their selling price will recover the incremental costs of installing gas. More recently there has been an increase in the public perception that electricity should be adopted for space and water heating because it is environmentally preferable. Elements such as these suggest that while the RIB rate structure is on the surface directionally beneficial to the competitiveness of natural gas there are other factors to consider which the Companies submit mean that the premise in the question cannot be unequivocally supported.

31.0 Reference: Exhibit B-1, Tab 1 pp. 18, 27 Natural Gas vs. Other Energy Sources

The Application states that the price advantage relative to electricity has gradually declined as natural gas rates increased with rising commodity costs, while electricity rates remained relatively constant. It also states the magnitude of future electricity rate increases is uncertain as BC Hydro balances electricity self-sustainability and other government objectives going forward.

31.1 In a recent proceeding before the Commission, the BC Hydro 2008 Long Term Acquisition Plan (2008 LTAP), BC Hydro put forward evidence related to its long term rate increase forecast in real terms in that proceeding's Exhibit B-3 BCUC IR 1.7.1 Attachment 1.

Response:

Confirmed.

31.2 Please attach a copy of the 2008 LTAP Exhibit B-3 BCUC IR 1.7.1 Attachment 1 in your response.

Response:

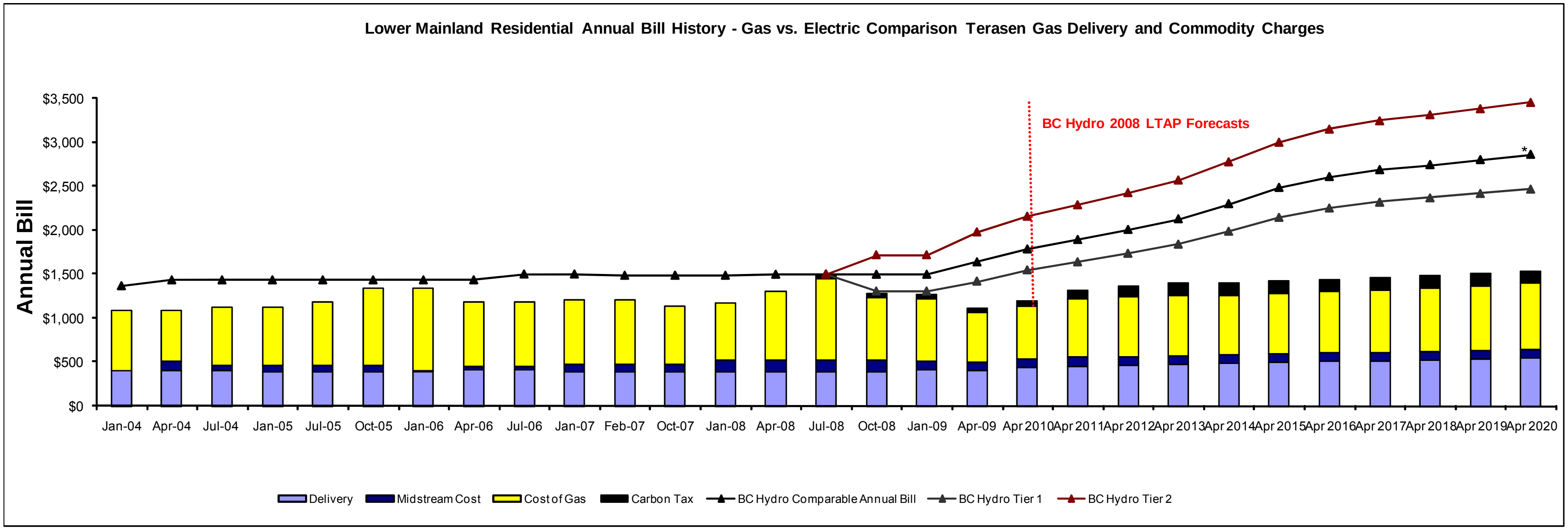
Please refer to Attachment 31.2.

31.3 BC Hydro, in Exhibit B-3 BCUC IR 1.7.1 Attachment 1 on page 7 of 9, forecasts: "For the following eight years the forecast of annual rate increases in real terms are estimated to be as follows: for F2011, 7 per cent; for F2012 through F2014, 4 per cent; for F2015 and F2016, 6 per cent; for F2017, 3 per cent; and for F2018, 1 per cent. Nominal rate increases for each year would be around 2 per cent higher, based on the forecast of inflation. As noted previously, for the F2019 to F2028 period, rates are assumed to rise at the rate of inflation (B.C. Consumer Price Index (CPI)), forecast at 2.1 per cent per year."

31.3.1 Given the electric price information from the 2008 LTAP and the gas price forecast in Figure 3.3 (Tab 1, page 28 of the Application), please provide an amended Figure 3.1.1 for the years 2004 to 2020. State the assumptions and also provide a working spreadsheet of the model.

<u>Response:</u>

See Attachment 31.3.1 for the working spreadsheet model. Amended Figure 3.1.1 follows:



Assumes:

Natural gas use of 95 GJ

Efficiency of gas equipment is 90% relative to 100% for electricity

BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

TGI Basic Charge per month and Delivery Charge per GJ for 2010 and 2011 are as per the TGI 2010 and 2011 Revenue Requirement Application and increased by 2% for years 2012 to 2020, (Rate Riders 3, 4, and 5 are held constant at 2011 applied for rates).

TGI Cost of Gas per GJ Charge is based on AECO monthly forward prices averaged for year, as at May 11. 2009

TGI Midstream Charge per GJ is held constant at rates effective January 1, 2009

Calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% (inclusive of the applicable 1% rate rider)

31.4 Please discuss if one should expect the margin between residential gas rates and future Tier 2 BC Hydro residential rates to increase over the next number of years.

Response:

While the graph in the response to BCUC IR1.31.3.1 above shows that the margin between residential gas rates and future BC Hydro RIB Step 2 rates may increase over time there are many uncertainties that are not captured in this simplified depiction of the future. These uncertainties and other issues are discussed below:

- As discussed in BCUC IR 1.31.1 above the RIB Step 2 rate is not the relevant comparator to residential natural gas rates in all cases. Smaller and more energy-efficient dwellings may get much or all of their space and water heating energy requirements from electricity consumption below the Step 2 consumption threshold.

- Natural gas operating costs for space heating need to be a significantly below the comparable electricity costs in order to recover the extra upfront capital costs for natural gas space heating equipment relative to electricity. The cost of electricity needs to exceed the cost of natural gas by an amount in the order of $10/GJ (Exhibit B-1, Tab 1, Page 31, Figure 3.4).

- Carbon taxes and other disincentives against natural gas & fossil fuel consumption are likely to increase over time (beyond the $1.50 per GJ for 2012 and after included in the chart above). In addition public perceptions about using natural gas may continue to become increasingly negative.

- Residential gas rates are more subject to commodity market volatility within the annual cycle while electric rates are likely to change once per year as revenue requirements and rate changes.

- Natural gas commodity price forecasts will change over time. Economic conditions, natural gas supply / demand balance and other factors will change over time and expectations about the differentials between gas and electricity rates will change accordingly.

- The provincial government has made policy commitments in support of low electricity rates. There are several references in the 2007 BC Energy Plan in support maintaining low electricity rates, such as, for example, on p.15 where continued support for electricity trading is discussed as a means "to keep electricity rates low for all British Columbians." UCA Section 43 (1.1) from the 2008 amendments to the Utilities Commission Act now requires BC Hydro to file a report with the Commission annually comparing BC Hydro's rates to electricity rates in other jurisdictions including an assessment of whether BC Hydro's rates are competitive with those in the other jurisdictions. There is obvious conflict between the sustained high electricity rate increases forecast in the LTAP and the province's commitment to low electricity rates. Over the longer term the province's commitment to low electricity rates is likely to be a factor which will moderate the rate increases that BC Hydro will ultimately be allowed to implement.

- The 2008 amendments to the Utilities Commission Act also overturned the elements of the Commission's Decision on BC Hydro's 2007 Rate Design Application pertaining to rate rebalancing between the rate classes which, if not overturned, would have increased residential rates by more than 10% over three years. While the government's reasons for overturning portions of the 2007 RDA Decision are not known the impact of the legislation change was to reduce rate impacts for residential electricity consumers.

32.0 Reference: Exhibit B-1, Tab 1 p. 20 Business Risk

The Application states that changed public perception would lead people to increasingly turn to other alternatives to meet their space and water heating requirements over time. The Application mentions new energy alternatives such as air source heat pumps and ground source heat pumps being introduced as alternatives.

32.1 Does TGI expect that the new focus on energy conservation and efficiency and investments in energy alternatives could lead to lower demand for gas and therefore decrease in price pressure on the market-based natural gas commodity prices? Why or why not?

Response:

At this point, Terasen Gas believes that the current forward prices as presented in the natural gas marketplace reflect all currently available information relevant to natural gas supply and demand for future periods. This includes information related to increased focus by governments and customers on energy conservation and efficiency and investments in energy alternatives which, all else being equal, likely reduces demand for natural gas in the future. However, to the degree that this energy conservation and demand reduction offsets the multitude of other factors that influence natural gas prices, future prices may or may not decrease. The natural gas environment in which Terasen Gas operates is an inter-connected North American marketplace in which supply and demand are impacted by many variables. While short term factors pressuring prices downward include ample natural gas storage levels, economic downturn and mild weather conditions, longer term factors resulting in higher price levels include lower forecast natural gas production levels, rising demand from economic recovery, long run production costs and natural gas prices relative to other competing fuels (such as fuel oil or electricity). The amount of potential demand reduction created by energy conservation relative to these other supply and demand factors will determine whether or not it influences natural gas prices downward in the future and remains to be seen. It is not unreasonable to assume, all else being equal, that energy conservation leading to reduced demand and lower prices will incent producers to scale back on their drilling efforts in order to cut costs. This, in turn, would eventually lead to less available supply which, all else being equal, would result in upward pressure on future prices in order to incent producers to resume drilling activity.

33.0 Reference: Exhibit B-1, Tab 1, p. 28, Figure 3.3 Forecast Business Risks

33.1 Given the cost advantage for natural gas shown in Figure 3.3 - AECO Prices vs. Electric Equivalent Commodity Component Current Prices as of May 11, 2009, has today's forecast of the business risk decreased for the next five years?

Response:

Figure 3.3 indicates that based on the May 11, 2009 forecast gas commodity prices (forward curve), natural gas has a cost advantage against electricity on an operating cost basis over the next five years. However, it does not follow that Terasen Gas' forecast of business risk has decreased for that period. There are a number of factors and uncertainties that must be taken into consideration:

- Historical AECO prices are reflective of actual market conditions and specific events that impacted market prices. The forward curve is reflective of the market's current perception of supply and demand and cannot be predictive of market specific events that can impact near term prices. Where prices ultimately settle and become historical prices market factors can be significantly different due to the multitude of short term supply and demand variables that can influence price in the current or near term market. For example, only twelve months ago, the forward price curve for natural gas today for the same period was significantly higher than it is today. In other words, there still remains a great deal of volatility and uncertainty around future natural gas price movements, impacting the Terasen Gas cost of gas and therefore future rates (See also the Response to CEC IR 1.33.1).
- The comparison in prices are based on the assumption of 90% efficiency for natural gas relative to 100% for electricity for heating requirements, representative of high-efficiency equipment used by new customers. However it is absent any consideration of the required recovery of the up front capital cost difference and higher maintenance costs between a natural gas heated home and a home heated by electricity, as outlined in Section 3.4 of the Application, which places natural gas at a disadvantage when it comes to attracting new customers. In addition, the average efficiency of existing customers is estimated to be approximately 75% relative to electricity, which means the competitive advantage to retaining existing customers is greatly reduced.
- The comparison makes assumptions about future rate increases to BC Hydro's rates (see following response to BCUC IR 1.33.2). However, although there is general expectation that there will be upward pressure on BC Hydro rates in future years, there still remains considerable uncertain on the timing, degree of change and the impact of on Step 1 versus Step 2 rates.

The introduction of the carbon tax effective July 1, 2008 in the amount of approximately \$0.50/GJ and increasing each year by about \$0.25/GJ until 2012 when it reaches \$1.50/GJ represents a significant price disadvantage for natural gas relative to electricity which did not exist in the past. There also remains uncertainty regarding future increases to carbon taxes.

33.2 Please provide the source and forecast assumptions for the Step 1 and Step 2 Electric Equivalent Forecast.

Response:

Figure 3.3 includes a number of assumptions in the derivation of the forecast for the Step 1 and Step 2 commodity component electric equivalent prices. The base electricity rates for the forecast were derived from the BC Hydro Residential Inclining Block ("RIB") Rate Zone 1 equal to \$0.0597/kWh for Step 1 and \$0.0835/kWh (\$0.0827/kWh plus 1% deferral account rate rider) for Step 2 effective April 1, 2009 per the BC Hydro F2009/2010 Revenue Requirements Application decision. For each subsequent April, these electricity rates were increased by an inflation factor of 2% per year. In the future, it is expected that the Step 2 rate will be adjusted from period to period to reflect new information regarding the cost of new electricity supply. However, in its decision regarding the BC Hydro RIB Application, the Commission did not determine how those adjustments would be implemented and in fact in the Reasons for Decision stated that "the allocation of future revenue requirement increases between the Step 1 and the Step 2 rates will be reviewed on case by case basis each time BC Hydro makes an application to change its estimate of the cost of new supply". Nevertheless, it is generally accepted that BC Hydro's cost of new supply will be higher than the current rates however, given the uncertainty on how increases will be implemented, Terasen Gas has assumed average inflation to the electricity rates of 2% per year.

Next, these electricity rates were converted to dollar per GJ equivalents by multiplying them by a conversion factor of 277.78. Then, the prices were adjusted by a factor of 90% based on the assumption that the efficiency of new gas equipment is assumed to be 90% relative to 100% for electricity.

Following this, the Terasen Gas current fixed basic and delivery charge amounting to \$4.29/GJ and the Terasen Gas current Midstream rate of \$1.015/GJ were deducted. Given the uncertainty around future changes to these rates, it was assumed that these rates were constant over the forecast period. While it is recognized that these rates and charges may change over time, the changes are not expected to be material with respect to the electric equivalent values forecast in the figure.

Finally, the carbon tax, applicable to natural gas and not electricity, was deducted, increasing by approximately $0.25/GJ each July until 2012 and held constant at $1.50/GJ thereafter.

The result of these calculations is the forecast commodity component of the electric equivalent Step 1 and Step 2 prices which is then compared to the AECO natural gas forward price curve in Figure 3.3 to assess Terasen Gas' future competitiveness relative to electricity rates on a variable basis. The detailed calculations and formulas for this figure are discussed in the response to the following BCUC IR 1.33.3.

It should be mentioned, as outlined in Section 3.4 of the ROE and Capital Structure Application, that, as Figure 3.3 indicates, while TGI has a competitive advantage against electricity on an variable cost basis over the next five years using the current forward curve (as of May 11, 2009), TGI requires a significant operating cost advantage to overcome the upfront capital cost differential for a natural gas versus an electrically heated home.

33.3 Please provide Figure 3.3 in a working Excel spreadsheet.

Response:

Attachment 33.3 contains the working Excel spreadsheet used to derive Figure 3.3. Please note that this spreadsheet has been updated for some incorrect information relating to the Terasen Gas Midstream rates used in the calculation of the Electric Equivalent for the period April 2004 to September 2008. Figure 3.3 in the ROE and Capital Structure Application included forecast Midstream rates for some of this period as opposed to actual Midstream rates, which are now included in the spreadsheet. An adjustment for an electricity rate change effective July 2006 excluded in the ROE and Capital Structure Application has also been made and is now included in the spreadsheet. These changes are not material with respect to historical information in Figure 3.3 and do not change the forecast electric equivalent prices or their position relative to AECO forward prices.

The assumptions and basis for the calculations in the spreadsheet are discussed in the previous response to BCUC IR 1.33.2.

34.0 Reference: Exhibit B-1, Tab 1 p. 30 Business Risk - Volatility

34.1 Figure 3.3.2 has two views for each gas year: (i) a "with no market volatility" that reflects only the forward curve pricing and (ii) a "with upward market volatility" that adds a volatility adjustment factor of approximately 30 percent to the floating volumes based on historical and current market conditions. In TGI's view, which is the more likely scenario in Figure 3.3.2? Please explain your answer.

Response:

At this point in time, Terasen Gas does not know which of the two gas cost scenarios, one with no market volatility or the other with upward market volatility as presented in Figure 3.3.2, is more likely given the volatile nature of the natural gas marketplace and difficulty in predicting future natural gas price movements. Terasen Gas does not believe it should be expected to predict future gas prices or decide which scenario is more likely to occur but rather should take appropriate measures to protect customers from potential market price volatility that could occur in the future.

The best information Terasen Gas has related to future natural gas prices is the recent forward price curve as presented in the marketplace. Terasen Gas recognizes that this forward curve may change over time and so has also presented the scenario of future gas costs with upward market volatility in an attempt to illustrate potential upward price movements that may reasonably be expected to occur in the future. While there is also the potential for future downward price movements, Terasen Gas has displayed the upward market volatility scenario in order to illustrate the impacts of upward price movements on Terasen Gas' competitive position, on a variable cost basis, relative to electricity rates. In addition, there is an absolute limit to how far prices can fall due to downward price movements over the long term and current prices are below the cost of finding and development as discussed in the Application so the potential for increases is greater than the potential for decreases.

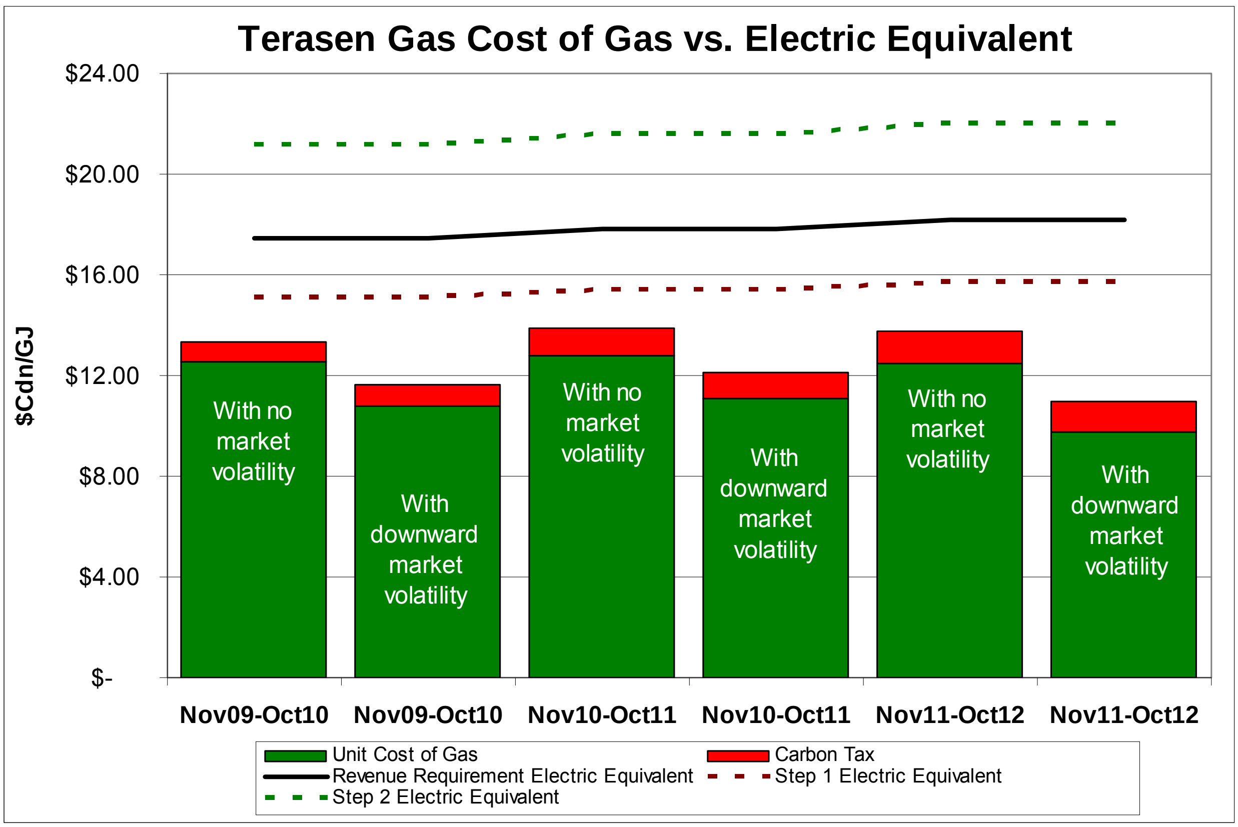
As the Application outlines in Section 3.4 regarding Business Risks, Terasen Gas requires a significant operating cost advantage to overcome the upfront capital cost differential for a natural gas versus an electrically heated home, regardless of any upward or downward market price volatility that occurs in the future.

34.1.1 Is there a third view where there is a downward pressure on gas commodity price? If not, why not?

Response:

The volatility in the natural gas marketplace could affect prices both upwardly and downwardly in the future. Figure 3.3.2 on page 30 of Tab 1 shows the Terasen Gas forecast cost of gas, with and without upward market volatility, compared to the forecast electric equivalent. This was presented to illustrate the point that upward market volatility can have a significant impact on the unit cost of gas, as has been witnessed in the past, and therefore, adversely affect Terasen Gas' competitiveness with electricity rates. Future prices could also move downwards and so Terasen Gas is presenting in the figure below a forecast cost of gas under a scenario with downward price volatility.

Terasen Gas Forecast Cost of Gas vs. Electric Equivalent



However, while one might conclude that Terasen Gas has a significant cost advantage relative to the forecast electric equivalents under this downward market volatility scenario, Terasen Gas still requires a significant variable cost advantage to overcome the upfront capital cost differential for a natural gas versus an electrically heated home as discussed in Section 3.4 of the ROE and Capital Structure Application. While Terasen Gas recognizes that future prices may move up or down, it is concerned with competing with electricity rates under either scenario, from a total cost perspective, in order to attract new customers and continue future growth. However, the potential for future upward market price pressure, which always exists in such a volatile energy marketplace, is of particular concern to Terasen Gas as outlined in Section 3.4 of the Application.

35.0 Reference: Exhibit B-1, Tab 1 p. 31 Business Risk – Alternative Energy

35.1 Please show the breakdown of the costs in Figure 3.4. For example, how is the cost of a new furnace and ducting/installations at $7,000 after calculating rebate? Why do new furnaces only last 18 years? Please provide the bases for assumptions.

Response:

Figure 3.4 is intended to illustrate cost differences between a electric baseboard and natural gas forced air system home. The actual operating cost difference that is needed to pay back the difference in the capital cost will be determined by the actual energy use in the home, the actual prices paid for the appliances, the costs to installations these appliances, and how the customer pays for the appliances.

Habart & Associates Consulting Inc. estimates the cost of ducting at between $2 and $3 per sq ft of house space, and $1,700[15] for a 90% AFUE furnace; the costs Terasen Gas provided in Figure 3.4 is based on a 2,500 sq ft house. The table below represents only the capital cost for purchasing and installing a natural gas forced air system.

Habart & Associates estimates the cost to install electric baseboards in a 2,500 sq ft home for the contractor to be about $2,500.

Capital cost for High Efficient Furnace (90% AFUE)	$1,700.00[1]
Ducting and installation ($2 X 2500 sq ft)	$5,000.00
Furnace installation	$300.00
Total	$7,000.00

The comparison is cost to the customer (in this case, the builder) and does not account for any grants or rebates that the developer may receive. Due to the varying availability of grants or manufacture rebates a rebate has not been used in the example. A further reason that a rebate was not included in this calculation is that rebate programs can come and go over time

The 18-year service life is supported by research conducted by the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Terasen has consistently

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[15] Price provided by Habart & Associates is congruent with contractor pricing, in the February 2009 Refrigerative Supply catalogue. This is the price the builder or developer would pay from the wholesaler for a new home. In a retrofit application, the home owner would pay the contractor a retail price of about $3,200.

used a 18 years service life in other fillings to the BCUC and any life cycle cost analysis we conduct.

35.2 Is TGI informed by market research studies with respect to decision-making over the choice of electric baseboards and natural gas forced air heated homes? Do customers prefer natural gas forced air furnace to electric baseboards? Please provide the conclusions of those studies used by TGI.

<u>Response:</u>

Primary Market Research at Terasen can be broadly divided into four streams:

- customer satisfaction;
- program evaluation;
- consumer behaviour and attitudes; and
- ad hoc.

Each study is designed to meet the needs of various internal and external stakeholders, including the BCUC. They provide information necessary to meet regulatory reporting requirements; to undertake enhancements to customer service; improve program effectiveness, and assist management in the decision making process.

There are five customer satisfaction surveys undertaken each year. Three of the studies: Small Commercial, Large Commercial, and Builders and Developers are conducted annually. A fourth, Residential, is fielded three times a year, while the fifth, the Customer Satisfaction Tracking Study ("CSTS") is continually fielded throughout the year. Scores from the first four studies are used to develop the Customer Satisfaction Index Score which is reported to the BCUC. The CSTS is a transactional based study, the results from which are used both as a teaching tool for field staff and to monitor customer satisfaction with Operations performance in three areas: Emergency Response, Meter Exchange, and New Service Installations.

Other studies that are undertaken on a regular basis include the Gas Safety Awareness (every three years), the Residential End Use Study (4-5 years) and the Corporate Image Study (two years). Ad hoc studies are conducted to meet specific needs such as in the support of project or program development activities. An example would be studies related to the Terasen Customer Care Enhancement Project that was filed as a CPCN Application in June 2009. Ad Tracking studies are conducted during large scale, long-term advertising campaigns to gauge their effectiveness and to assist with the development of marketing and communications materials in support of the campaign.

Part of the 2007 Ad Tracking Study explored commitment to home heating systems and perceptions of different home heating fuel types among BC residents (customers and non-customers). These specific questions were developed in mid-April 2007 and asked between April 25 and November 4. Conversion Model™ segmentation was used to understand the residential home heating market. Conversion Model is a way of understanding customer commitment and customer acquisition. This was used to provide Terasen Gas with greater understanding of the usage and predispositions toward various forms of home heating systems, whether they are fueled by gas or alternative types of energy.

In particular, the Conversion Model analysis for the Ad Tracking Study was designed to answer the following questions:

- Which are the strongest heating systems in the residential market?
- Which heating systems are threats to Natural Gas usage?
- Which home heating systems are opportunities for market share gains?
- Which heating systems should Terasen Gas target with marketing campaigns?
- What attributes or messaging should be used by Terasen Gas to influence homeowners to desire gas-based home heating systems?

The report concluded that commitment to forced-air heating using a gas furnace was greater than commitment to electric baseboard heaters among users of these heating technologies. This was consistent across all three regions (Lower Mainland, Interior and Vancouver Island). However it should be noted that approximately half the forced-air/gas furnace users were not committed to the technology and even among those committed to the technology the majority were not entrenched in their commitment. Furthermore the report concluded that greater than one-in-three were unhappy with their current heating system and were seeking to replace it with an alternative. The study also found that commitment levels to current heating technologies were lower than other utility global norms.

The study also assessed the attraction of each of these heating systems to non-users. In all three regions, electric baseboard heaters had substantially lower attraction than forced-air gas furnaces. However the study did not consider the importance of heating systems when consumers purchase homes and as such we cannot provide an assessment of the relative importance of heating system type against other factors such as cost, location, living space etc. And while one of the study's objectives was to isolate what attributes or messaging should be used by Terasen Gas to influence homeowners to desire gas-based home heating systems further research will be required to see if any increased desire on the part of the customers translated into a greater willingness of builders to provide natural gas heating.

The annual Terasen Gas Builder and Developer Study does not address the issue of motivation for installing natural gas in new homes. Furthermore, builders who do not install natural gas are not included in the study. Therefore we have no way of assessing whether or not consumer demand drives heating technology choice. Given the relatively low levels of commitment to heating systems identified in the study it would be reasonable to conclude that heating system type is not top-of-mind when a home is being purchased. As a consequence, it is likely that builders and developers are influenced more by the cost of each heating technology type rather than consumer demand for a particular heating fuel or technology. This conclusion is supported by TGI low capture rate in multi-family dwellings.

36.0 Reference: Exhibit B-1, Tab 1 p. 33 Business Risk

36.1 The Application states that code changes have resulted in approximately a doubling of costs. Please detail the code changes that have doubled the cost of gas hot water tanks? Show the average actual retail prices over the past several years for various models.

Response:

In the Application on page 33 of the Business Risk (Tab 1), there was a misstatement. The doubling of costs related to water heaters is caused by increases in installation costs due to code changes for new construction, "not for safety related changes".

Installation costs for gas water heaters have doubled due to minimum furnace efficiency requirement that took effect on January 1, 2008[16]. Due to the type of vent required for high efficient gas furnaces, the hot water tank is no longer able to share the same vent as the furnace. As a result, the costs to install a gas water heater include the costs for a separate vent, framing, roof penetration, and indirectly, lost of sellable floor space. Material costs for a 4" B Vent are about $300 to $400, labour cost associated to the installation, framing, and roof penetration are about $600.The location of the mechanical room is dictated by where the vent for the water heater can be installed.

After the new replacement regulations for gas furnaces come into effect December 31, 2009,[17] the cost to the homeowner to vent an existing gas hot water heater will be considerable. Once the existing furnace is replaced with a furnace with CPVC venting the existing "B Vent" will need to be replaced with a smaller 'B Vent'. Material costs for a 4" B Vent are about $300 to $400, the labor cost for the installation is difficult to estimate for existing homes and could be in the range of $200 to $500.

As the doubling of cost of gas water heaters was misstated, it is not necessary to show the average actual retail prices over the past several years for various models. However, the average cost for a 40-gallon gas hot water tank is about $500³ and a 60-gallon tank is about $750.00[18].

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[16] A new mandatory minimum furnace efficiency requirement that took effect on January 1, 2008 for new residential, commercial and institutional construction under the provincial *Energy Efficiency Act* and the Energy Efficiency Standards Regulations. The minimum efficiency for natural gas forced air furnaces must achieve an Annual Fuel Utilization Efficiency (AFUE) equal to or greater then 90%.

[17] A new mandatory minimum furnace efficiency requirement will take effect on December 31, 2009 for replacement application in pre-existing residential dwellings also under the provincial *Energy Efficiency Act* and the Energy Efficiency Standards Regulations. The minimum efficiency for natural gas forced air furnaces must achieve an Annual Fuel Utilization Efficiency (AFUE) equal to or greater then 90%.

[18] Prices from the Home Depot and do not include installation.

36.2 Do the new tanks have any operational advantages or longer expected life?

Response:

For residential gas water heaters there have been no changes to operating efficiencies since the EF was set at .67 -.0005V in September 2004 i.e. a 40 gallon tank would be .65 (40 – (.0005 X 40).

Installation "best practices" can reduce standby losses, by installing thermal traps and insulating accessible piping. The life expectancy has not change in the past few years, however regular maintenance can extend the service life and help maintain its operating efficiency.

37.0 Reference: Exhibit B-1, Tab 1 p. 33 Business Risk

37.1 Please explain why TGI is only able to capture 18% of multiple unit construction? With the large margin between gas and Tier 2 RIB rates, does TGI anticipate improving its performance in the future?

Response:

There are a number of factors that influence TGI's capture rate of multi-family dwellings, including the installation costs, physical space requirements, operational costs, and of course the demand associated with the particular energy source.

The low capture rates experienced by TGI in the multi-family dwelling sector are a reflection of the behaviour exhibited by builders/developers, who in most cases choose to install electrical space heating equipment over natural gas. There are a number of factors that are influencing their decision, with the most significant being the higher capital and installation costs associated with natural gas space heating (as compared to electrical baseboards). Further, multi-family units are smaller than single family detached homes, and as such natural gas space heating in multi-family dwellings can be a more difficult installation. Lastly, in many cases it does not make sense for a developer to install gas heating appliances in individual suites as the heating equipment takes up valuable square footage that can be used for another purpose.

Developers tend to install equipment that they believe meets customer desires and provides the greatest margin, or return on developers investment. Though the Tier 2 RIB rate is in effect, we do not believe, and have not seen evidence that, the price spread between the Tier 2 Rate and gas rates is enough to translate into increased demand from end use customers to limit the use of electricity for heating applications. Secondly, due to the smaller size of multi-family dwellings compared to single family detached buildings, there is less electricity used to heat a multi-family unit and therefore, a smaller portion of the customer's electricity bill would be priced at the Tier 2 RIB rate.

Lastly, Developers are currently being encouraged by local policy to build projects that achieve some level of "green" certification, through rating systems such as LEED and Built Green. This results in additional construction costs to earn credits within the rating system to achieve the certification. These rating systems allow certification to be achieved with electric baseboard heating. The developers then choose this lowest capital cost heating alternative to offset some of the additional related construction costs. The unintended consequences are more encouragement to install electric baseboard heating.

Due to these factors, a developer is currently still incented to install the lowest cost heating application (electricity), as the margin on an electrically heated home is higher than that of a gas heated home. TGI is certainly working towards improving its capture rates in this customer segment, and continues to maintain ongoing communications with the builder/developer community, promoting the use of natural gas and increasing awareness with regards to natural gas being part of the long-term solution to climate change. Since 2004, we have increased and refocused our sales staff to focus on the multifamily and vertical subdivision sector. Our sales staff have been focused on meeting with, and putting on workshops for builders, developers, architects and engineers to educate and influence the choice of heating applications. We have changed our main extension test and added an option to "pipe to the suite", both having been approved by the BCUC, to help ensure that gas remains a competitive option for both developers and end use customers.

However, absent formal policies in British Columbia which identify the right fuel for the right application at the right time and that specifically encourage end use gas applications, it is reasonable to assume that British Columbian's will continue to view natural gas as a fossil fuel that is contributing to the global climate change issues. It is also reasonable to assume the significant difference in installation costs between natural gas space heating and electrical baseboard heating will continue. Given this, it is reasonable to assume that even with the high level of marketing efforts we continue to provide, and also the margin between gas and Tier 2 RIB rates, only marginal increases to capture rates for multi-family dwellings will occur.

38.0 Reference: Exhibit B-1, Tab 1, p. 37 Current government policies and initiatives

"Gas use should be encouraged, as the right fuel for the application, but current government policies and initiatives provide consumers with a contrary message."

The 2007 BC Energy Plan on page 21 states: "It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas."

38.1 Does the 2007 BC Energy Plan acknowledge that natural gas plays a role in the energy mix used in British Columbia?

Response:

The Terasen Utilities agree that the referenced quote from the 2007 BC Energy Plan acknowledges a role for natural gas in the energy mix in British Columbia. Other policy action items in the 2007 BC Energy Plan are clearly supportive of growth and development of the natural gas resource base in the province. The Terasen Utilities have been active in drawing attention to these aspects of the 2007 BC Energy Plan in various Commission proceedings such as the BC Hydro 2007 Rate Design Application and the BC Hydro 2008 LTAP proceeding.

Subsequent to the issuance of the 2007 BC Energy Plan, however, the provincial government has issued various pieces of legislation such as the Greenhouse Gas Reduction Targets Act (Bill 44 - 2007), the Greenhouse Gas Reduction (Cap and Trade) Act (Bill 18 - 2008), the Carbon Tax Act (Bill 37 - 2008) and others which have placed considerable uncertainty on what the province's view is of using natural gas in the province. Although the Terasen Utilities have advocated for the view that natural gas should be put to its highest and best use in high efficiency space and water heating, both within the province and elsewhere, various other participants in the public discussion of energy issues in BC expect a future in which the role of natural gas is reduced relative to today.

39.0 Reference: 2008 Annual Report Business Risk

39.1 Please provide a copy of the most recent Terasen Inc. Annual Report with the covering letter from Mr. Jesperson, President and CEO.

Response:

Please see Attachment 39.1.

39.2 The Annual Report speaks in glowing terms to the continuing strong financial and investment results and the stability, growth and excellence for the future. Why is this document so different in its tone and expectations to Tab 1 of the Application?

Response:

The Terasen Utilities see no difference or conflict in what appears in the annual report and this Application. They are in effect two sides to the same coin.

The letter demonstrates factually the Companies' ability to show a steady progression in improved results, including financials, through effective resource allocation and business risk management under incentive regulation, prudent investment of growth capital, and overall cost containment.

Stability, past and present, largely rests on the continuation of a progressive regulatory environment which keeps management focused on things over which they have the greatest ability to influence and avoids penalizing investors for management operating in a fashion which is in the best public interest. The effective combination of incentives, deferral arrangements such as the Revenue Stabilization Adjustment Mechanism (RSAM), EEC programs, etc. provide for aligning the interests of the Company and its customers as well as the importance management places on maintaining positive stakeholder communications/relations, etc.

Looking forward, confidence is based upon maintaining strong business processes and the culture of operational excellence we have evolved related to maintaining a strong safety focus, customer satisfaction levels, prudent financial/cost management and operating in an environmentally responsible fashion. Terasen will strive to maintain the strength and depth of the management team who, assuming the Company will be allowed an opportunity to earn a fair return in the future, are committed to pursuing value added growth opportunities such as the LNG project at Mt. Hayes, the Whistler pipeline extension, alternative and district energy systems, etc.

Importantly, and as included in the referenced disclosure documents and other sources of public information, Terasen believes that the Canadian regulatory environment including BC, is on the threshold of remedying the growing gap between current allowed returns and those required to meet the legal fair return standard. Canadian regulators are taking notice of the growing body of evidence that the current formula based returns are too low and out of step with comparable utilities in other jurisdictions. A case in point is the recent TQM decision which increased the effective ROE by almost 300 basis points and which recognized that US utilities which have consistently been granted higher returns and more robust capital structures by their regulators were reasonable comparators for Canadian utilities. Numerous studies and papers in recent years have commented on the inadequacy of Canadian formula based regulated rates of return including studies commissioned by the OEB and CGA.

In its 2006 decision the BCUC gave credence to the comparable earnings approach to estimating a fair return but gave little or no weight to the results. Additional data to support this approach is presented by the expert witnesses in this proceeding. So while the Company has established a solid track record of financial performance and growth and is optimistic about its prospects for the future, it is in large measure dependent on being granted both a fair and reasonable return and an appropriate capital structure to foster the investment climate needed to meet customers' evolving requirements in the future and assist in dealing with the challenges relating to climate change and energy and environmental policies both Provincial and Federal. With the expiry of PBR and related incentive earnings, even greater importance is placed on the Commission ensuring that investors are afforded a fair return using comparables as a key determinant. This Application places the evidence before the Commission that will allow it to establish such a return for the Terasen Utilities and help us to ensure that the energy needs of the province are met in the years to come.

40.0 Reference: Exhibit B-1, Tab 1 Business Risk

40.1 In TGI's view, which of the following is the biggest component of business risk currently faced by TGI: supply risk, market risk, regulatory risk, competitiveness, operating risk? Please quantify and rank in order of significance.

Response:

In TGI's view, and given the definition of business risk in the Application being the ability to of the utility to earn a fair return on its investment and recover that investment over time, the risks in order of significance are:

1. Regulatory risk
2. Market risk
3. Competitive risk
4. Operating risk
5. Supply risk

It is not possible to quantify such risks precisely other than in gross terms but generally the ranking of the significance of each factor is influenced in part by how well TGI can control or mitigate such risks.

In the case of regulatory risk, the Commission acts pursuant to its powers under the Utilities Commission Act, but within that framework has significant discretion in the exercise of those powers. Cost of service items may be approved or denied that impact the Terasen Utilities ability to recover the investments required to serve their customers. The Commission establishes the level of return that is allowed to be included in rates. If that return is not sufficient to achieve a fair return then which the Company asserts is currently the case under the AAM, then this goes to one of the fundamental tenants of the definition of business risk. As a rule the Commission avoids retroactive rate making so the Company will never be in a position to recoup the foregone return on its investment due to the current gap between the approved ROE and a fair return on equity.

Market risk and competitive risk are inter-related and it is difficult assess which one is of greater significance than the other. The Company understands market risk to be factors that impact demand for natural gas and other energy forms. These will include economic conditions and activity, customer attitudes and perceptions, government policies that impact energy use and conservation, tax policies, business conditions and restrictions on operations including Aboriginal Rights, etc. These can lead to impacts on demand/throughput even when actual rates are competitive with other energy forms.

Competitive risk is generally seen as related to the price competitiveness of natural gas against other energy forms, however as noted above, changing customer preferences and influences can shift demand away from natural gas even when it enjoys an apparent operating cost advantage as is currently the case due to recent softening in gas commodity prices. On a life cycle basis, as discussed in Tab 1 of the Application at page 31, natural gas must achieve an operating cost advantage of more than $10 per Gj in order to offset the higher capital cost of natural gas equipment versus electric heating which is not the case even with the current lower commodity costs and the market forward pricing of natural gas is increasing. These factors affect new customer attachment decisions and equipment replacement decisions at the end of their useful lives or on an accelerated basis in response to energy efficiency and conservation programs of Terasen or BC Hydro.

Operating risk is generally within the control of TGI and can be managed through effective use of risk management policies and controls and through insurance. The Company has a strong track record and long history of providing safe reliable gas delivery service to its customer base and delivering major construction projects on time and within budget. The inherent nature of natural gas requires that adequate safety precautions and procedures be established and maintained to control such risks and TGI has put these in place for all its operations. That said there are factors beyond the reasonable control of the Company such as damages by third parties and natural events that can have a detrimental impact on the system. The Company carries what it considers to be adequate levels of insurance coverage for such reasonably foreseeable events short of total destruction of the system.

Supply risk can be defined as being able to source and obtain adequate supplies of natural gas to meet forecast peak demand of customers throughout the year. For near term supply risk, the Company prepares an annual Price Risk Management Plan and an Annual Contracting Plan, both of which are approved by the BCUC each year and individual supply contracts are filed with the Commission. The Company manages its supply portfolio and transportation and storage resources to ensure it can meet its requirements. The Company is dependent on the WEI transmission system in BC for the bulk of its natural gas supplies and a sustained outage on that system could impair its ability to continuing to serve all the customers on the TGI, TGVI and TGW systems. Short of connecting addition supply resources out of Alberta there are limits to what additional risk mitigation can be achieved in this area. Over the longer term, security of supply is a risk that can only be managed contractually. The Terasen Utilities do not own any gas producing resources and the Western Canada Sedimentary Basis is experiencing production declines. New sources of supply from shale deposits are being developed in Northern BC and there is the prospect of offshore gas being developed some time in the future though that is indeterminate at this time. There is also the potential for sourcing LNG supply into BC at some point in the future though no projects are currently at a stage of development sufficient to proceed.

40.2 TGI has not included an analysis of Supply risk, Operating risk and Regulatory risk in Business Risk Tab 1. Although some of these topics are commented on by the external expert witnesses hired by TGI, they should be addressed by the Company. Please provide an assessment of all business risks faced by TGI and the mitigation measures approved by the BCUC.

Response:

Regulatory Risk

As discussed by the external witnesses, the Terasen Utilities face regulatory risk in terms of the allowed ROE being established by the AAM, which yields results that are below the Fair Return Standard. In addition, the equity component of the capital structure of TGI as allowed by the Commission for rate-setting purposes is lower than appropriate. Both of these issues are addressed in this Application.

The BCUC has, in some of its proceedings, adopted capital cost caps or limitations, which can inappropriately transfer to the utility risks that are beyond its effective control.

The BCUC allows only taxes payable to be recovered in rates, which defers the recovery of taxes from customers to future periods, when competitive pressures or other business pressures may preclude or diminish the recovery of those taxes. This is in contract to US jurisdiction that allow deferred or normalized taxes to be recovered in current rates.

The regulatory process in B.C. has been affected by special directions to the BCUC and by legislation. Residential customers of BC Hydro have been sheltered from rate increases by legislation, which affects the competitive position of the Terasen Utilities in those markets. As discussed in the Application, the Provincial government has enacted GHG and other climate related legislation, and has amended the Utilities Commission Act to further its objectives.

In areas other than ROE and capital structure the regulatory environment in B.C. for the Terasen Utilities has generally been positive, but directions to the Commission that require the regulatory regime to assist in accomplishing the government's GHG and climate control objective could present serious challenges to the Terasen Utilities in future.

Supply Risk

To deal with Supply Risk, Terasen Gas has a long stand practise of preparing an annual Price Risk Management Plan ("PRMP") and an Annual Contracting Plan ("ACP") both of which are approved by the BCUC each year and individual supply contracts and hedging transactions are filed with the Commission. While the focus of the PRMP is on cost stability in a volatile natural gas marketplace, the ACP forms the physical gas supply resources to move gas from trading hubs to the Terasen Gas transmission system. These resources include: supply portfolio (commodity), transportation and storage resources to ensure firm delivery to customers.

The physical delivery of supply resources to the Terasen Gas system is dependent on the natural gas infrastructure that is in place in the Pacific Northwest and Alberta. The Company is heavily dependent on the WEI transmission system in BC for the bulk of its natural gas supplies and a sustained outage on that system could impair its ability to continuing to serve all the customers on the TGI, TGVI and TGW systems. The largest supply of gas into the Terasen Utilities' system comes from the Westcoast system. In addition to its Aitken Creek storage movements on Westcoast's T-North and T-South system, the Company purchases the majority of its gas supply from Station 2 and flows it down on Westcoast's T-South for consumption in the market areas. Aside from supply from Aitken Creek storage, a vast majority of the supply at Station 2 (over 80%) originates from three large processing plants on the Westcoast system. The reliability of Westcoast's processing plants and delivery systems are of utmost importance to Terasen Gas and its customers. Disruptions on Westcoast, in particular, during cold weather can have significant gas supply consequences for the Company given the magnitude of reliance that is placed on this system. While the Terasen Utilities has developed a diversified resource portfolio comprised of market-area Huntingdon supply, market area storage contracts, SCP-delivered AECO and Kingsgate supply and on-system LNG, a high reliance on the Westcoast system will continue to be a reality creating supply risk, unless other significant infrastructure is developed that allows Terasen Gas to move significant supplies to its service areas (Terasen is not aware of plans for any such infrastructure development).

Over the longer term, security of supply is a risk that can only be managed contractually. These contractual arrangements more than likely involve making a commitment to gas supply over a long term to fund the development of infrastructure for the region. The Terasen Utilities do not own any gas producing resources and the Western Canada Sedimentary Basis is experiencing production declines. New sources of supply from shale deposits are being developed in Northern BC and there is the prospect of offshore gas being developed some time in the future though that is indeterminate at this time. There is also the potential for sourcing some LNG supply into BC in the future though no projects are currently at a stage of development sufficient to proceed.

As the Pacific Northwest continues to grow, which increases the demand for energy for the region as whole, all utilities (both electric and natural gas) are continually reviewing the need for new infrastructure projects that help meet these requirements. Terasen Gas has played an active role in recent years from a planning perspective through such organizations such as the Northwest Gas Association. Terasen Gas has also been proactive in making commitments to infrastructure in the region, such as securing long term contracts that resulted in a expansion Jackson Prairie storage. Closer to home, TGI has made a commitment to the Mount Haynes LNG project located on Vancouver Island. These commitments help TGI manage the energy needs of our customers, while also diversifying supply resources.

Terasen Gas will continue to mitigate supply risk in the short term through the development of its Annual Contracting Plan, providing diversity within the commodity, transportation and storage resources portfolio as well as in the longer term by continuing to monitor, and participate in, regional infrastructure developments and opportunities that benefit core customers.

Operating Risk

The company is exposed to various operational risks, such as pipeline leaks; accidental damage to, or fatigue cracks in mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and other accidents involving natural gas or propane which could result in significant operational disruptions and/or environmental liability.

A major natural disaster, such as an earthquake affecting the Greater Vancouver region or Vancouver Island, could severely damage Terasen Gas' or Terasen Gas Vancouver Island (TGVI) natural gas transmission and distribution systems.

Terasen Gas and TGVI natural gas transmission and distribution systems require ongoing maintenance, improvement and replacement. If the systems are not able to be maintained, service disruptions and increase costs may be experienced.

The company maintains comprehensive facility risk assessment, pipeline integrity management and damage prevention programs and pipeline security systems as preventative measures to mitigate the risk of pipeline failure or other loss of system integrity. These programs are intended to reduce both the likelihood and severity of the business interruption and/or environmental liability that could result from a pipeline failure or loss of integrity. The company also has an insurance program which provides coverage for business interruption, liability and property damage, although the coverage offered by this program is limited.

Terasen completes an annual risk assessment to identify principal risks to the organization using a Board approved Enterprise Risk Management Framework. Two Operational Risks have been identified as principal risks to the organization. Following is a brief summary of the risks identified and mitigation strategies:

1. Infrastructure Failure – Catastrophic failure of natural gas or propane infrastructure could result in significant injuries, loss of life or wide spread outages.

   Mitigation Strategies

   - Integrity Management Plan (IMP)/Hazard Mitigation Programs per Annex N of CSA Z662 (covers external interference, corrosion, natural hazards, equipment failure, manufacturing defects and operator error). Included will be regular reviews of programs, plus implementation of program metrics to ensure programs are mitigating risks as expected.
   - The TGI system includes pipe assets that are in excess of 40 years old. As these assets age, the potential for incidents increases. To mitigate this risk, the IMP includes many activities to monitor asset condition, with frequencies established based on industry and company experience. This would include the following:
     i. Natural Hazards Database
     ii. Permit Process
     iii. Vegetation management on a 5 year cycle
     iv. Pigging (in-line inspection procedures)
     v. Preventative Maintenance program
   - High risk areas like LNG plant are on a specified assessment cycle complete with their own integrity plans.
   - Environment, Health & Safety plans.
   - Assessments and audits completed on within regular cycles.
   - Transmission Operations System Review (TOSR)
   - Seismic Risk Review

2. IT System Failure – Loss of functionality of IT servers in the data centre at Surrey Operations could result in limited ability to utilize some business applications.

   Mitigation Strategies

   - Terasen has initiated the "Disaster Recovery Services Project" to assist in defining the organization's IT disaster recovery requirements and to provide recommendations on recovery strategies and level of planning necessary to support current and future needs. Business continuity and technology recovery strengthen Terasen's emergency preparedness program by ensuring critical and essential business processes are restored within pre-established recovery time objectives. It also plans for the recovery of the remaining business operations, allowing for the ultimate return to a permanent operating environment.

- Terasen has also taken the following proactive measures:

    i. Construction of the data centre room to earthquake specifications.

    ii. Non-water fire extinguisher

    iii. Back-up generator

    iv. Regular anti-virus updates

WRITTEN TESTIMONY OF MR. CARMICHAEL

41.0 Reference: Exhibit B-1, Tab 2 Written Testimony of Mr. Carmichael p. 6

In his written testimony, Mr. Carmichael says that the formulas "incorrectly assume that utility ROEs should decline proportionately with the forecast Canada long bond yields."

41.1 In Mr. Carmichael's view, is this assumption incorrect since 1994 when the AAM was first introduced? If so, why were the formulas supported by the utilities, the rating agencies and the stakeholders? If not, please specify the particular financial and capital market circumstances where the assumptions underlying the formulas would become incorrect.

Response:

Prior to 1994, regulators in Canada considered a broad range of factors in determining an appropriate capital structure and return on common equity for a utility. These factors included the expected outlook during the utility's test year for the national economy, expected levels of corporate profitability and capital re-investment, developments in and the outlook for capital markets, changes in the utility's risk profile and estimates for the utility's cost of common equity based upon the comparable earnings test (an accounting based determination of historic and expected returns on book common equity), the discounted cash flow test (a determination of the capital market's required rate of return) and the capital asset pricing model/equity risk premium test. Regulators reviewed this information and determined an appropriate capital structure and return on common equity for the utility based on informed judgment and expected conditions during the company's test year. This process was time consuming for the regulator as well as utility management and frequently resulted in only marginal changes in the utility's capital structure and rate of return on common equity. The adoption of the automated adjustment mechanism gave rise to a more transparent, more predictable, more timely (that is, the application of the formula process reduced the likelihood of regulatory lag), significantly less time consuming approach to the setting of a return on common equity. In the first few years following its introduction, the automatic adjustment mechanism gained some support from utilities, credit rating agencies and equity analysts due to the above positive attributes of the process.

The adoption of the automatic adjustment mechanism did however defer the review of an appropriate capital structure for the utility to a generic hearing which generally has occurred every four to five years rather than annually. In addition, the adjustment mechanism presupposes that changes in the utilities risk profile or a change in the required common equity return for other reasons will be compensated for by the changes in expected long term Government of Canada bond yields. As long term Canada yields have generally declined since 1994 (the BCUC expected average 30 year bond yield to be 7.75% in 1994), many customer-based participants in the regulatory process supported the use of the formula as returns on utility common equity have declined from approximately 10.75% to a current level of 8.47%, a decline of approximately 21%. Additionally, from time-to-time, the market for corporate risk tightens driving up the required equity risk premium while, at the same time, lenders "flee" to Government of Canada bonds driving down their yields. The decline in Government of Canada yields leads to a lower return on common equity produced by the formula.

The National Energy Board identified the problem of declining government bond yields and increasing corporate spreads in it recent Decision RH-1-2008, quoted below.

Support for the automatic adjustment mechanism coming from utilities and capital market participants began to recede in 2000 and 2001as such participants became aware that returns on common equity awarded in Canadian jurisdictions using an automatic adjustment mechanism tended to be lower (and in certain instances substantially lower) than returns awarded in the United States where returns on equity were being reviewed in a traditional fashion rather than being set mechanically. This difference in the awarded rates of return on common equity in Canada and the U.S. was presented in graphical form on page 43 on Mr. Carmichael's pre-filed testimony.

In a recent review of the National Energy Board's RH-2-94 automatic adjustment mechanism outlined in decision RH-1-2008 for Trans Quebec & Maritime Pipelines, the NEB concluded

> Also, the Board is of the view that there have been significant changes since 1994 in the financial markets as well as in general economic conditions. More specifically, Canadian financial markets have experienced greater globalization, the decline in the ratio of government debt to GDP has put downward pressure on Government of Canada bond yields, and the Canada/US exchange rate has appreciated and subsequently fallen. In the Board's view, one of the most significant changes since 1994 is the increased globalization of financial markets which translates into a higher level of competition for capital. When taken together, the Board is of the view that these changes cast doubt on some of the fundamentals underlying the RH-2-94 Formula as it relates to TQM.

> The RH-2-94 Formula relies on a single variable which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, the changes discussed above regarding the new business environment are examples of changes that, since 1994, may not have been captured by the RH-2-94 Formula. Over time, these omissions have the potential to grow and raise further doubt as to the applicability of the RH-2-94 Formula result for TQM for 2007 and 2008.

It is Mr. Carmichael's opinion that the National Energy Board has identified the economic and financial market circumstances under which the formulas employed by the NEB and the BCUC (which are similar) will calculate very doubtful results. The recent significant decline in Government of Canada long term yields and the expansion of corporate spreads has exacerbated the already existing doubts of capital market participants. These factors likely triggered a decision by the NEB to initiate a review of the RH-2-94 Decision at this time.

42.0 Reference: Exhibit B-1, Tab 2 Written Testimony of Mr. Carmichael p. 6

42.1 At page 6 of Mr. Carmichael's evidence he states that utility equity bases in Canada have been consistently lower than those in the US. What independent analysis has he done on Canadian vis-à-vis US regulations as they impact gas utility sales risk, commodity cost risk, prudency disallowance risk, or interest rate risk.

Response:

As part of Mr. Carmichael's investment banking activities, he has followed the deregulation of gas and electricity markets in the United States and Canada and formulated credit rating and financing strategies for Canadian companies operating in these industries. He has been involved in creating credit rating presentations on behalf of Canadian utility clients in advance of their initial rating by Moody's, Standard & Poor's and DBRS. These rating agencies as well as large sophisticated lenders and equity investors focus on the regulatory environment in which the prospective issuer of securities operate as each group attempts to understand the differences in regulation and other business risks faced by Canadian utilities versus those in the United States.

In preparation for this evidence, Mr. Carmichael updated himself on a number of regulatory developments in the U.S. In particular, he reviewed the concept of a "margin decoupling tracker" which has been adopted for a number of gas, electric and water distribution utilities. For U.S. gas distribution companies, a number have been allowed by their regulatory commissions to adjust rates, either upward or downward, in order to recover its forecast margin (revenue less the cost of gas) independent of customer usage patterns. This mechanism was originally intended to hold the utility's financial performance harmless from deterioration due to energy conservation efforts but in some jurisdiction it has been expanded to include weather normalization adjustments. The gas utilities currently using a decoupling account include, among others, Piedmont Natural Gas (North Carolina), Northwest Natural Gas (Oregon), Public Service of North Carolina, New Jersey Natural Gas, South Jersey Gas, Baltimore Gas & Electric and Washington Gas Light (Maryland). The decoupling mechanism allows the utility to recover its projected margin independent of customer usage patterns which removes much of the utility's sales risk.

Many utilities also have approved riders which allow them to recover all prudently incurred gas costs from customers which eliminate substantially all commodity price risk for the utility.

Mr. Carmichael did not undertaken a specific review of prudency disallowance risk or interest rate risk because they appear to be similar in Canada and the U.S.

Mr. Carmichael believes that it is noteworthy that Moody's identifies Piedmont Natural Gas, Northwest Natural Gas and Public Service of North Carolina as peers of Terasen Gas in a quote on page 39 of his pre-filed evidence. It is also noteworthy that Moody's rates regulatory support in these jurisdictions as Aaa compared to Aa assigned to Terasen Gas.

42.2 At footnote 17 at page 16 of Appendix 4, a 2008 study commissioned by the Canadian Gas Association and conducted by the National Economic Research Associates, the footnote stated that capital structures are "deemed" in Canada and this contrasts with the US, where LDCs are predominantly allowed to choose their capital structure within a band of reasonableness. In Mr. Carmichael's opinion, could this have led to higher equity ratios in the US compared to Canada?

Response:

The deeming of an appropriate capital structure is one of a number of factors which has lead to the disparity between utility common equity bases in Canada and the U.S. When the process of deeming a capital structure was first accepted by regulators in Canada, it was required due to the fact that many utilities were operating regulated and non-regulated businesses within the same corporate entity and regulators were concerned that the utility operations were being forced to pay a higher cost of capital due to the potentially higher risk non regulated activities. The discussion before regulatory bodies was lengthy and often complex and ultimately required the regulator to indirectly determine an acceptable capital structure for the non-regulated operations such that the non-regulated operations were financially self sustaining and fully capable of supporting the capital structure that regulators thought to be appropriate. The process of subdividing the consolidated entity by the regulator sometime led to an allocation to the utility capital structure of all preferred shares outstanding plus a common equity base which may have been somewhat less than actually required for utility due to the perceived "riskiness" of the non-regulated operations.

Once determined and upheld by the regulator over time, the utility common equity base percentages have changed only marginally over the years, often notwithstanding the restructuring of the utilities into holding companies with pure play utilities subsidiaries and non-regulated subsidiaries, the injection of greater amounts of common equity on a consolidated basis, and the reduced availability of equity capital for the utility subsidiary.

42.3 Mr. Carmichael states that TGI is disadvantaged to compete with other highly equity capitalized US and international utilities for debt and equity funding due to globalization and greater competition. Please demonstrate this by comparing the TGI experiences in raising debt and equity with that of other Canadian, US and international utilities.

Response:

TGI is a wholly owned subsidiary of Fortis Inc., a diversified gas and electric utility holding company, and as a result does not raise common equity directly from capital markets.

Terasen Gas was able to access the Canadian long term debt market over the period 2006 to 2009 at a reasonable but escalating cost.

43.0 Reference: Exhibit B-1, Tab 2 Written Testimony of Mr. Carmichael p. 18

In his testimony, Mr. Carmichael described the extremely modest inflationary expectations and reduction of Government of Canada investable bond product due to nine years of federal government surpluses and strong financial performance.

43.1 Does Mr. Carmichael have evidence to believe that the underlying trends that led to the 65 year low in benchmark GCB bond yields will continue? Please comment on the latest federal debt management strategy and latest estimate of the current fiscal year budget deficit and how they could reverse the financial performance of the last nine years.

Response:

Currently there is significant economic slack in the North American and global economies with unemployment and factory surplus capacity rising reflecting the global economic slowdown. Commodity prices have declined reflecting the reduction in demand. Inflation is not expected to be an area of concern for the next few years.

As discussed in the response to BCUC 1.15.1, the federal government has announced a significant deficit in 2009-2010 (approximately $50 billion) followed by a series of annual deficits until 2014-2015. This will be a departure from the government's financial performance over the past nine years as it steadily reduced its debt to GDP level by repaying previously incurred debt. Canada's debt to GDP level is now one of the lowest in the G8 group of countries and this has placed Canada in a stronger position to weather the current economic storm. Capital market participants will accept government deficit policies so long as the federal government's intention to reduce annual deficits and pay down debt remains a firm and observable commitment. Capital market participants do not like deficits; however, they do recognize the difference between cyclical deficits and structural deficits which have plagued the Government of Canada in the past.

As also noted in the response to BCUC 1.15.1, the capital markets have not reacted to the announced federal government deficit plan as long and short term interest rates have either remained approximately steady or gone down since the budget was announced.

44.0 Reference: Exhibit B-1, Tab 2 Written Testimony of Mr. Carmichael p. 22

44.1 On page 22, Mr. Carmichael itemizes the TGI long term debt financings since September 2006, indicating the yield at issuance and the spread between long Canada yields. How do these yields and spreads to long GCB yields compare to those of other Canadian utilities of similar debt rating and to other Canadian corporate bonds of similar debt rating? Do the TGI financings indicate an inability to access the markets on competitive terms?

Response:

The following tables provide details of actual issues carried out by Terasen Gas on the dates indicated and indicative pricing for similarly rated utilities and corporate issuers on the same date.

Date of Pricing	Terasen Gas Spread (bps)	Enbridge Gas Spread (bps)	Union Gas Spread (bps)	FortisBC Spread (bps)	30 year Canada Yield (%)
9/25/2006	136	104	112	125	4.19
10/1/2007	148	140	148	160	4.52
5/12/2008	163	155	165	180	4.17
2/23/2009	285	280	295	310	3.70

(1) Terasen Gas spreads are actual, other spreads are indicative spreads provided by Scotia Capital to issuers.
(2) Terasen Gas is rated (A/A3/A) by (DBRS, Moody's and S&P), Enbridge Gas is rated (A/NR/A-), Union Gas is rated (A/NR/BBB+) and FortisBC is rated (BBB(high), Baa2, NR)

Date of Pricing	Terasen Gas Spread (bps)	BC Ferry Spread (bps)	GTAA Spread (bps)	407 Intl Spread (bps)	30 year Canada Yield (%)
9/25/2006	136	97	124	95	4.19
10/1/2007	148	115	130	115	4.52
5/12/2008	163	145	150	150	4.17
2/23/2009	285	330	335	310	3.70

(1) Terasen Gas spreads are actual other spreads are indicative spreads provided to issuers by Scotia Capital.
(2) Terasen Gas is rated (A/A3/A) by (DBRS/Moody's/S&P), BC Ferry is rated (A(low)/nr/A-), GTAA is rated (A/NR/A-) and 407 International is rated (A/NR/A).

The tables indicate that Terasen Gas has been able to access the debt market on competitive terms; however, like other corporate issuers, the spread of Terasen Gas debenture over 30 year Canada bonds has increased dramatically over the period. The table also indicates that Terasen Gas debentures must compete against infrastructure issuers such as GTAA, BC Ferry and 407 International.

45.0 Reference: Exhibit B-1, Tab 2 Written Testimony of Mr. Carmichael pp. 30, 31

45.1 At pages 30 and 31 Mr. Carmichael speaks to investors' valuations of common shares. Given the impact of market volatility on earnings yields and dividend yields, would not investors prefer the stable earnings and high dividends of TGI?

Response:

Market volatility (that is, significant increases or decreases in the price of a common share or the market for common shares as a whole) causes similar volatility in the earnings (or dividend) yield as the earnings yield equals the earnings per common share of the company divided by the price of the common share. If the price of the common share declines by 50% the earnings yield will double (assuming that the expected earnings per share remain constant). Assuming a constant earnings stream, a decline in the price of a utility stock reflects an increase in the required rate of return which investors are using to discount the utility's expected future earnings stream. In other words, the utility's cost of common equity has been increased by investors.

With regard to dividends paid by Terasen Gas, the amount paid essentially reflects BCUC decisions regarding an appropriate equity base for the Company's regulated operations. The Company has agreed to maintain a percentage of common equity to the total capital of the Company that is at least as much as that determined by the BCUC from time to time for rate making purposes. The Company's dividend policy is intended to ensure that it maintains at least as much common equity as that deemed by the BCUC for rate making purposes. From this vantage point, it is in my view inappropriate to refer to dividend payments by the Company as being "high".

45.2 Please show the earnings yields, dividend yields and total yields of relatively pure play Canadian gas or petroleum utilities compared to the S&P/TSX during the past year by month, as well as annually for each of the last four years and, to the extent possible, for the last 30 years. Incorporate TGI data to the extent they are available and including Enbridge, Trans Canada Pipeline and any other applicable Canadian investor-owned utilities.

Response:

Please refer to Attachment 45.2.

46.0 Reference: Exhibit B-1, Tab 2 Written Testimony of Mr. Carmichael p. 35

46.1 Mr. Carmichael identifies that the public and government funding for infrastructure projects in Canada will be massive and will compete with utility financings. Please indicate the expected impact on financing rates and the spreads between future TGI financings and those of governments and Private Public Partnerships.

Response:

The evolving form of infrastructure financing in Canada encompasses the transfer of business and financing risk from governments to private sector consortiums which construct, own, finance and operate the infrastructure facilities on behalf of government. These consortiums may consist of a developer, a contractor, a supplier of technology and/or fuel for the facility, banks to provide short term construction financing and long term debt investors to provide debt maturities of up to 30 years depending on the facilities. The sponsoring government normally provides some form of indirect credit enhancement by way of a long term "capacity agreement" or long term purchase agreement which provides the single purpose infrastructure company adequate cash flow to service the debt in most reasonable circumstances.

Alternately, an indirectly government owned but non-guaranteed infrastructure company is formed to own, operate and finance existing or new assets. Depending on the business of the company, it may be regulated or it may operate under a long term agreement (for example, a power purchase agreement) with an agent of the sponsoring government.

The credit ratings for these financings usually fall in the A category while spreads on the long term debt financing for the assets fall currently in the range of 350 to 400 basis points above the appropriate term Government of Canada bond.

As more governments adopt this form of public/private financing and infrastructure investment continues to increase in magnitude, greater competition for funds will evolve from utility-like projects with the indirect support of provincial and possibly the federal government in Canada. Governments are willing to pay a premium to have private sector consortiums absorb risks which have traditionally been backstopped by the government sponsor. This provides lenders to earn a premium return on a government supported debt obligation. As the demand for infrastructure financing grows upward pressure will be placed on the credit spreads of Terasen Gas debentures in order for these securities to compete with similar term infrastructure financing.

47.0 Reference: Exhibit B-1, Tab 2 Written Testimony of Mr. Carmichael p. 37

47.1 Mr. Carmichael states that TGI long bond interest spreads peaked in January 2009 at approximately 390 to 400 basis points over the 30 year long term Canada bond. Is this relevant data or a short term event resulting from the world wide financial crisis? Please show the same credit spreads for each month of the last year up to and including July 2009.

Response:

Indicative long term spreads for the issuance of 30 year debentures for Terasen Gas over the past year are as follows:

Date	Indicative 30 year Credit Spread Above Benchmark Canada Bond
7/7/2008	+165
7/14/2008	+195
7/21/2008	+195
7/28/2008	+195
8/5/2008	+195
8/11/2008	+195
9/2/2008	+215
9/8/2008	+225
9/22/2008	+230
9/29/2008	+250
10/6/2008	+260
10/15/2008	+310
10/20/2008	+320
10/27/2008	+330
11/3/2008	+330
11/10/2008	+330
11/17/2008	+310
11/24/2008	+315
12/1/2008	+315
12/8/2008	+360
1/5/2009	+420
1/12/2009	+350

Date	Indicative 30 year Credit Spread Above Benchmark Canada Bond
1/19/2009	+350
1/26/2009	+350
2/2/2009	+340
2/10/2009	+330
2/17/2009	+305
2/23/2009	+285
3/2/2009	+285
3/9/2009	+290
3/16/2009	+285
3/23/2009	+280
3/30/2009	+285
4/6/2009	+285
4/13/2009	+280
4/20/2009	+260
4/27/2009	+255
5/4/2009	+245
5/11/2009	+240
5/18/2009	+225
5/25/2009	+220
6/1/2009	+180
6/8/2009	+165
6/15/2009	+160
6/22/2009	+165
6/29/2009	+180
7/6/2009	+170

Source: Scotia Capital Inc.

The relevance of the comment is that the spread expansion from165 bps at the beginning of July 2008 to approximately 400 bps in January 2009 was unprecedented in its speed (6 months) and magnitude (approximately 240%). As well, lenders were demanding credit spreads for utility credits that approximated the equity risk premiums usually assigned to those same utilities to determine their cost of common equity capital under automatic adjustment formulas. Since debt capital ranks prior to common equity capital and is better protected from the business risk of the utility, it is not logical that approximately the same risk premium should satisfy both lenders and investors.

The comment is also relevant in the context of the automatic adjustment mechanism not being directionally correct. As utility credit spreads were expanding, the formula was predicting that returns on common equity should be reduced to reflect the lower yields in the Government of Canada long bond market.

48.0 Reference: Exhibit B-1, Tab 2 & Cover Letter p. 30 Written Testimony of Mr. Carmichael pp. 39, 40 Continuation of the TGVI Company Specific Risk Premium

In his written testimony, Mr. Carmichael quoted comments from Moody's in its most recent credit rating report (dated May 27, 2008).

> "TGI's financial metrics are generally weaker than those of its A3 rated global LDC peers such as Piedmont ………… and sister Company, TGVI. Moody's recognizes that TGI's relatively weaker financial metrics are largely a function of the relatively low deemed equity and allowed ROE permitted by the BCUC. In general, Canadian deemed equity ratios and allowed ROEs are low relative to those of other jurisdictions and TGI's are among the lowest in Canada. However, TGI's A3 senior unsecured rating reflects Moody's view that …. a significant degree by the supportiveness of the business and regulatory environments in which TGI operates."

48.1 Do Terasen Utilities agree with Moody's comments that TGI's financial metrics are generally weaker than TGVI's?

Response:

Terasen Utilities does agree with Moody's comments that TGI's financial metrics are weaker than TGVI.

48.1.1 If no, please explain the basis of your disagreement.

Response:

Not applicable given response to 48.1.

48.1.2 If yes, please comment on the reasonableness of TGVI's request in the Application to continue with the 70 basis points premium to the low risk utility ROE on the basis that TGVI's business risks were greater than TGI.

Response:

TGVI's 70 basis point risk premium is a function of its higher business risk relative to TGI. While both TGI and TGVI submit that business risks have increased for both entities, justifying in part the request for an appropriate benchmark ROE, both TGI and TGVI do not believe there has been a material change in the relative business risks between the two utilities, which leads to the conclusion that the 70 basis point risk premium that TGVI receives in excess of TGI is still appropriate. The fact that TGVI has stronger credit metrics is in part a function of a more appropriate equity thickness and ROE than TGI, relative to its higher business risk, and the existence of the Revenue Deficiency Deferral Account and Special Direction which allow TGVI to collect rates relative to competitive alternatives to amortize the RDDA balance.

48.2 Do Terasen Utilities agree with Moody's description of the supportiveness of the business and regulatory environments in which TGI operates?

Response:

The Terasen Utilities believe that Moody's reference to the supportive business environment is a reference primarily to the robust economic environment enjoyed by BC over the past number of years, as well as provincial government support for TGVI in the form of the royalty revenue payments, whereas the reference to the regulatory environment is primarily a reference to both the constructive relationship with the regulator and intervenors in the province that has seen the adoption of positive regulatory constructs such as PBR and certain deferral accounts. With respect to the above understanding, Terasen Utilities does agree for the most part with Moody's comments.

However, the business and regulatory environment is not static. As noted in the Application, Terasen Utilities believes the business environment has become more challenging, with the recent action by the BC government with respect to environmental legislation and the carbon tax examples of increased business risk. The continuation of a low ROE and equity thickness are factors that the Terasen Utilities believe are examples of a less supportive regulatory environment. Terasen Utilities believes that the increasing business risk and a continuation of low ROE and equity thickness may over time diminish Moody's view of the supportive operating environment facing Terasen Utilities.

48.2.1 If no, please explain if TGI agrees with its credit rating given by Moody's.

Response:

TGI believes that Moody's credit rating classification is reasonable.

48.2.2 If yes, please comment on the reasonableness of BMO Capital Markets' analyst report dated December 7, 2006 that the ROE adjustment mechanism that was in place in B.C. likely "violates the Fair Return Standard and is confiscatory" (x-ref: Tab 2 p. 38 lines 8 to 12).

Response:

The comment in the BMO report is in reference to the allowed ROE and is not an assessment of the general supportiveness of the regulatory environment. The BMO comment is reasonable in light of the low level of the ROE, which Terasen Utilities submits is not adequately addressing the Fair Return Standard.

While TGI agrees in general with the comments by Moody's regarding the supportive business and regulatory environment, as noted in the response to BCUC IR 1.48.2, this does not by extension mean that the low ROE and equity thickness is reasonable, nor does TGI believe that Moody's is implying that the low ROE and equity thickness is reasonable because of their general assertion regarding the supportive regulatory environment.

49.0 Reference: Exhibit B-1, Tab 2 Written Testimony of Mr. Carmichael p. 40

49.1 Mr. Carmichael states that "Credit rating agencies and sophisticated lenders rank changes to regulatory environment as the single largest risk faced by a utility." Would the supportive regulatory environment afforded TGI not then be the single greatest asset for TGI? In the past, rating agencies have supported the BCUC AAM as providing regulatory certainty; therefore, could there be concern if BCUC abandoned the AAM?

Response:

Historically the regulatory environment in BC has been seen as supportive and assisted in propping up the rating that would otherwise likely be lower, certainly on the basis of the credit metrics. A supportive environment does not change the fact that the metrics are weak, nor does it justify an ROE and equity ratio much lower than peers who also have supportive environments. Secondly, the transparency and certainty provided by the current AAM may be a positive but it does not mean that the credit rating agencies believe the ROE's produced by it are appropriate or supportive.

As noted in my pre-filed testimony, Terasen Gas has achieved its credit rating based primarily on the positive view held by credit rating agencies of its supportive regulatory environment (Moody's rates Terasen Gas' regulatory support as Aa) and positive business environment in the Company's service area. These factors have, in the past, compensated for the Company's somewhat weaker financial performance (rated Ba). The views of credit rating agencies and lenders can change rapidly however given new or different circumstances. For example, in 2002, Standard & Poor's put virtually all utilities in Canada on credit watch with a negative outlook, given S&P's concern regarding the direction of regulation in Canada. Utility issuers remained on credit watch until S&P had an opportunity to talk with regulators in every major jurisdiction.

The view of lenders and investors on both the business environment and regulatory environment is not static. There is a growing consensus that the AAM is not working and the ROE's are too low. There is an expectation that regulators will take appropriate action, especially in light of the TQM decision, and announced or expected reviews of the automatic adjustment formulas by the NEB and in Alberta and Ontario. Lack of progress on ROE and the AAM may change the perception of regulatory support by lenders and investors.

Similarly the economic impact of the global recession will likely dampen the strength of the British Columbia economy and this will remove another support to the credit rating of the Company.

With both of these previously positive factors potentially becoming negatives in the eyes of rating agencies, lenders and investors, the Company's ability to attract capital on reasonable terms would become much more difficult.

Regulatory stability is appreciated by the capital markets; however, if evidence suggests that the current methodology (in this case, the automatic adjustment formula) is not working and that the financial performance of the utility is suffering, then credit rating agencies, lenders and investors are likely to applaud reasonable changes in the adjustment mechanism that improve the financial performance of the utility.

If such a change to an improved return on equity adjustment mechanism is not undertaken, Mr. Carmichael believes lenders and investors would look to other regulatory jurisdictions which have adopted more appropriate methods of determining an appropriate return or to non-regulated infrastructure projects which also offer attractive returns. Moreover, the shift away from an AAM to an approach that resulted in higher returns that meet the fair return standard would not be expected to be seen by the credit rating agencies as an increase to the utility's business risk profile. Conversely, if the BCUC and other Canadian regulators retain the AAM in the face of the TQM decision, then credit rating agencies are unlikely to maintain the view that the current regulatory environment is supportive.

50.0 Reference: Exhibit B-1, Tab 2 Written Testimony of Mr. Carmichael, p. 43
Exchange Rate Adjustments

Allowed returns (i.e., as shown in Chart 2 on p. 43) and other financial variables of Canadian and US firms are frequently compared directly to one another across countries, without adjusting for movements in the CDN: USD exchange rate.

50.1 Please state clearly what market integration implies about the direct comparability of raw returns across countries.

Response:

Market integration implies that long term real rates of return adjusted for risk should be approximately the same.

50.2 Does market integration imply that there should be comparability between real (i.e., inflation-adjusted), exchange rate-adjusted, risk-adjusted returns, and does not necessarily imply that nominal raw returns should be directly comparable across markets in different countries and different currencies?

Response:

Nominal raw returns are likely to be less accurate than real, exchange rate adjusted, risk adjusted returns; however, movement in the relationship between regulated nominal returns in Canada and the U.S. cannot be overlooked.

50.2.1 If nominal raw returns in different currencies are not in fact generally directly comparable, without any adjustments whatsoever, across even integrated markets, then what is special about the case of the Canadian and US utility returns that allows for direct comparison of raw returns across countries?

Response:

It is not the specific level of the returns in Canada or the U.S. that should be of interest, it is the assertion that nominal utility rates of return in Canada declined relative to nominal returns in the U. S. following the introduction of rate of return formulas in Canada. Prior to the formulas introduction, the authors of the study found nominal rates of return in the two countries to be approximately equal.

50.3 Please calculate the cumulative percentage change of the CDN dollar against the USD during the past decade, (a) 1998 to 2008 and (b) 2003 to 2008 (x-ref: Tab 3, Schedule 1).

Response:

The cumulative change from: (a) 1998 to 2008 was 38.24% and (b) from 2003 to 2008 was 30.56%, both calculations based data on Schedule 1.

50.3.1 Even if the raw nominal rate of return in Canada was less than the raw nominal rate of return in the USA, is it not possible that on a common-currency basis, after adjusting for the significant appreciation of the Canadian Dollar, that the return to investing in assets of similar credit risk (i.e., government bonds) was higher in Canada than the USA even if the raw return in Canada was lower?

Response:

It is possible.

50.3.2 Does this imply that even though the allowed return on Canadian utilities has been lower than the US utilities over the past decade that the returns when translated into a common currency are more similar and in fact in some cases higher for Canadian utilities?

Response:

Without identifying the common currency, the question cannot be answered.

WRITTEN EVIDENCE OF MS. MCSHANE

51.0 Reference: Exhibit B-1, Tab 3, Opinion of Ms. McShane, p. 7 Footnote

51.1 The footnote at the bottom of page 7 states that the Consensus forecast since 1997 has averaged 0.7 percent higher than actual yields. Is this a consistent forecast bias that should be adjusted for? Please explain.

Response:

There is no bias that needs adjustment. For clarification, the statement in footnote 3 refers to the forecast of 10-year Canada bond yields over the longer-term, as contrasted with the forecasts of 3-month and 12-month forward 10-year yields which have been used to estimate the long-term Canada bond yield for purposes of applying the existing automatic adjustment formula.

The point that Ms. McShane was making was that, throughout the period in question, the economic and capital market conditions which have transpired have resulted in average yields on long-term Canada bonds which are lower than what might reasonably have been expected in equilibrium. Over the longer-term, the yield on 10-year government bonds should reflect the expected long-term rate of inflation (currently expected to be approximately 2%), a real return equating to the productivity of capital (frequently estimated in the range of 2.5%-3%) and a premium for reinvestment risk. Over time, the forecast yields on 10-year government bonds for the longer-term have been in line with these building blocks.

52.0 Reference: Exhibit B-1, Tab 3, Opinion of Ms. McShane, p. 8 Figure 1 & Schedule 22

Ms. McShane opined that the allowed returns in the U.S. and Canada were comparable until automatic adjustment formulas tied to government bond yields became the norm.

52.1 Please explain what comparable means in light of movements in CDN/USD exchange rates and differences in inflation rates.

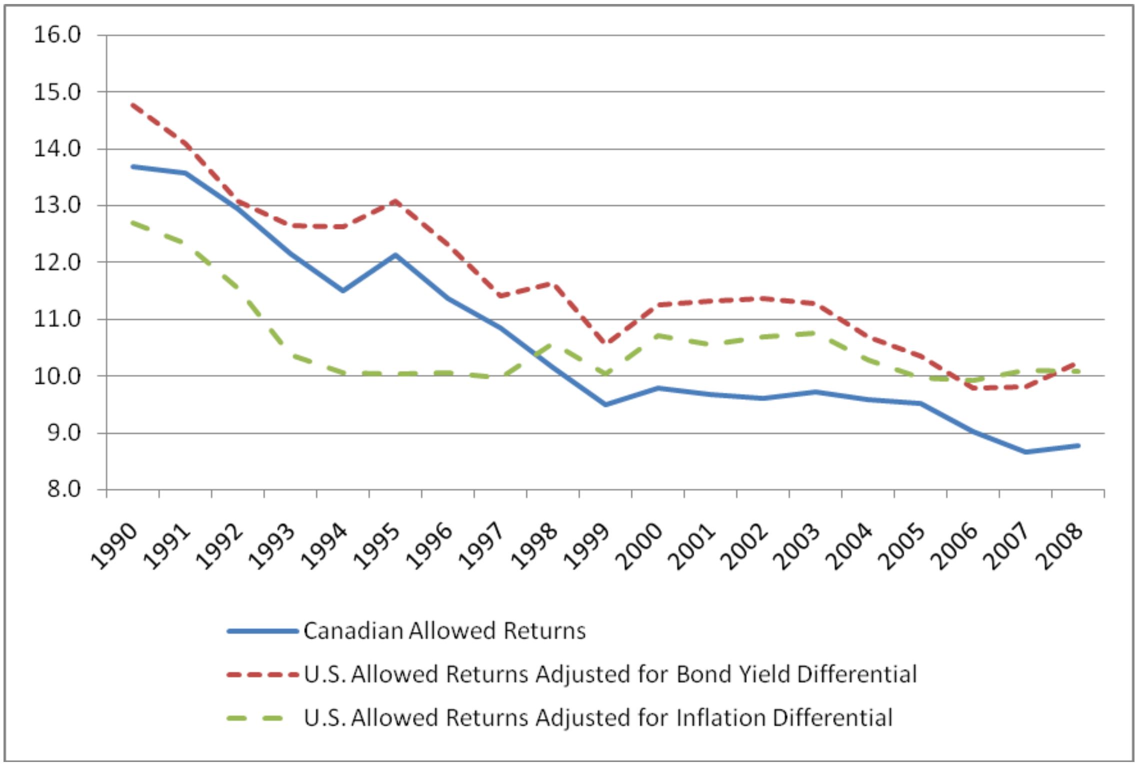
Response:

Comparable means in a similar cost of capital environment for investments of similar risk, the returns available to those investments should be comparable. Over the period since cross-over (1998-2008) on Figure 1, the difference in long-term government bond yields in Canada and the U.S. has been approximately 8 basis points. On this basis, in isolation, the average difference in ROEs should have been less than 10 basis points. The actual difference between the allowed returns in Canada and the allowed returns in the U.S. over that period was 1.4 percentage points. All other things equal, the impact of the expected exchange rate on cost of capital should be accounted for in differences in the long-run expected rate of inflation. Over the period 1998-2008, the consensus forecasts of the long-term rate of CPI inflation in the U.S. have averaged 2.4% compared to 2.0% in Canada. Thus, all other things equal, the cost of capital would be higher by 0.4% in the U.S. than in Canada. A recent study by the Bank of Canada, however, found that since government bond yields have converged in the two countries, the difference in cost of equity financing between the two countries is statistically insignificant (Lorie Zorn, *Estimating the Cost of Equity for Canadian and U.S. Firms*, Bank of Canada, Autumn 2007).

52.2 Please present Figure 1 with adjustments for (a) inflation rates; (b) exchange rates; and (c) both (a) and (b).

Response:

Please see response to BCUC 1.52.1 with respect to the relationships among inflation expectations, the exchange rate and the cost of capital. The figure below shows the allowed returns in Canada as per Figure 1 in Ms. McShane's testimony, in conjunction with (1) the allowed returns in the U.S. adjusted for the difference between the yields on U.S. and Canadian long-term government bonds during the corresponding year and (2) the allowed returns in the U.S. as adjusted for the difference in the consensus (Consensus Economics, *Consensus Forecasts*, April and October issues) long-term expected rate of inflation published in the corresponding years to which the allowed returns apply.



52.3 Is the U.S. utility statistics limited to actual awards in the particular year or do they include cases where an ROE was awarded from previous years?

Response:

The U.S. allowed returns are limited to awards made in the specific year.

53.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, p. 28 Credit Spreads

53.1 Please update Table 1 to add the most recent possible information, for example, add a column showing credit spreads as of July 2009.

Response:

The source documents required to update the table are no longer being distributed. The indicated spreads for TGI as of July 13, 2009 are 155 and 180 basis points for new 10-year and 30-year issues respectively.

53.2 Have credit spreads on corporate bonds over Government of Canada bonds generally narrowed over the past 6 months?

Response:

Yes, as indicated on line 729 of Ms. McShane's evidence. The point of the table was, as stated at lines 728-733, "this table underscores the potential magnitude of the incremental costs that are associated with being a BBB rated issuer, and the importance from both a cost and market access perspective of maintaining ratings in the A category. It bears noting that, in the case of a downgrade, the increased cost of debt would be borne by ratepayers over the full life of the issues." [emphasis added]

54.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, pp. 37, 38 Financial Statistics

54.1 On page 37 it is argued that reduced tax rates indicate a need to increase the common equity ratio to maintain EBITA. Is this rational if TGI is protected for actual tax expense?

Response:

Yes, it is rational. Ms. McShane understands that TGI and ratepayers are protected from changes in tax rates, not that it is protected on actual tax expense. Lower tax rates means less pre-tax income to cover interest expense. From a financial theory perspective, lower corporate income tax rates (when interest is deductible) also mean there is less of a cost savings benefit from debt leverage and thus, all other things equal, support lower debt ratios.

54.2 Table 5 on page 38 indicates financial statistics for TGI and others. Please indicate the requirements of TGI in its trust indentures and other binding debt related agreements, and the consequences if TGI falls below the required levels.

Response:

TGI has three primary financing agreements:

1. Trust Indenture for the Senior Unsecured Debentures

The majority of TGI's long term debt is senior unsecured debentures, issued pursuant to the Trust Indenture. The Trust Indenture includes a new issue incurrence test which restricts TGI from issuing new long term debt maturing 18 months or more from the date of issue unless TGI has annual available earnings which are greater than two times the interest on long term debt, including the new long term debt being issued. The covenant acts to restrict the amount and timing of new unsecured long term debt issued by TGI. If the test is not met, TGI would be restricted in the amount of new unsecured long term debt it could issue until the test could be met.

The test excludes the Purchase Money Mortgages, which are senior ranking obligations that are exempted.

2. Trust Indenture for the Purchase Money Mortgages

The Purchase Money Mortgages are senior, secured obligations of Terasen Gas, issued under a trust indenture. The Purchase Money Mortgages were issued in connection with the acquisition of the lower mainland gas distribution assets from BC Hydro, and those assets are pledged as security. The Purchase Money Mortgages are limited to a total issuance of $425 million, of which $275 million are currently outstanding and mature in 2015 and 2016. The PMM Trust Indenture has no financial test covenants.

3. Credit Agreement for the Operating Credit Facility

TGI maintains an unsecured revolving credit facility of $500 million through a syndicate of lenders. The agreement contains a financial covenant that TGI maintain a total debt to capital ratio of no more than 0.75 to 1.00, at each financial quarter end. If TGI fails to meet the covenant, it will be given a period of 60 days to obtain sufficient equity to cure the default. Further failure to provide sufficient equity will result in an event of default under the credit agreement which would allow the bank to demand payment of all outstanding debt balances and cancel the facility.

TGI would be required to negotiate a new facility, likely at higher rates to fund repayment of any outstanding balances. In addition, without a replacement facility, TGI would not be able to issue commercial paper, as investors require commercial paper programs to be backstopped by a credit facility. An additional effect would be the potential for providers of hedges to terminate and demand payment early, as hedge contracts provide early termination option when a counterparty defaults on credit documents.

55.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, p. 44 Risk Free Rate Analysis

55.1 The analysis uses the April Consensus forecast and yield spreads at that time. Is April an inappropriate point in time to do world and market events?

Response:

More precisely, the analysis used the April consensus as a point of departure. The April consensus in isolation produced a long term Canada bond yield forecast of 3.85% compared to the 4.25% relied upon for the application of the risk premium tests. With respect to whether April is an appropriate time due to world and market events, a utility must be in a position to raise capital and have the opportunity to earn a fair return, irrespective of the prevailing capital market conditions. Any cost of capital analysis must be done on the basis of the outlook for the capital markets available at the time, in both volatile capital markets or in markets that, in retrospect, turn out to have been overly sanguine.

55.1.1 What was the long Canada bond yield in April and July 2009? If the long Canada bond yields are expected to rise in 2010, would not the AAM sliding scale of .75 redress the impact of low risk free rate?

Response:

The long-term Canada bond yield averaged 3.7% during April 2009 and was 3.85% as of July 2, 2009. The forecast long-term Canada bond yield for mid-2010 using the June 2009 Consensus Forecast is approximately 4.25% (3.8% 10-year forecast yield plus a spread between 10-year and 30-year Canada bond yields of 0.5%). Using the existing benchmark ROE (9.145%) and long-term Canada bond yield (5.25%) and the existing AAM, the indicated low risk benchmark ROE in 2010 would be 8.4%. An ROE of 8.4% would not meet the fair return standard, and thus the AAM formula would not redress the impact of the low risk free rate.

56.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, p. 45 and Appendix B

CAPM

Ms. McShane states that there are some potential drawbacks with the CAPM. One potential drawback mentioned is a potential bias of the beta estimate. Ms. McShane's evidence deals with this by applying what in the finance profession is sometimes called a "shrinkage factor" by which the value of beta estimated from the data is manually moved toward the value "1.0". The addition of a second risk factor is also explored in line 1349 on page 54.

56.1 Would it also be possible to employ a richer industry-standard model that accounts for three risk factors, such the Fama-French Model cited in on page B-21?

Response:

It might be possible to do so if the premiums (sensitivities or "betas") for size and book/market values for different companies could be estimated and tested so that the results could be applied with a sufficient degree of confidence in their accuracy and stability.

56.2 If yes, please undertake such a Fama-French model estimation and report the regression results and the mean and standard deviation of the resulting implied return for TGI.

Response:

The application of the Fama French model is beyond the scope of Ms. McShane's testimony and would require significant time and effort with no guarantee that the results would provide robust estimates of the cost of equity.

57.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, pp. 49 - 51 Return Estimates

Table 6 reports point estimates of the mean, or average, risk premia. Table 7 reports point estimates of mean, or average, equity market returns.

57.1 Please update Table 6 to also report standard deviations of the annual risk premia and the resulting 95 percent confidence interval around the point estimate of the mean.

Response:

Updated Table 6 follows.

Table 6

Historic Risk Premiums		
	Versus Bond Total Returns	**Versus Bond Income Returns**
Arithmetic Averages		
(1947-2008)		
Canada	**4.6%**	**4.4%**
Standard Deviation	19.8%	17.5%
95% Confidence Interval	-34.2% to 43.4%	-29.9% to 38.7%
U.S.	**5.6%**	**6.2%**
Standard Deviation	20.4%	17.8%
95% Confidence Interval	-34.4% to 45.6%	-28.6% to 41.0%
(1952-2008)		
Canada	**3.20%**	**3.30%**
Standard Deviation	19.38%	17.11%
95% Confidence Interval	-34.8% to 41.2%	-30.2% to 36.8%
U.S.	**4.70%**	**5.50%**
Standard Deviation	20.70%	18.10%
95% Confidence Interval	-35.9% to 45.3%	-30.0% to 41.0%
Geometric Averages		
(1947-2008)		
Canada	**3.70%**	**3.20%**
Geometric Standard Deviation	19.8%	17.8%
95% Confidence Interval	-35.1% to 42.5%	-31.7% to 38.1%
U.S.	**4.60%**	**4.80%**
Geometric Standard Deviation	20.7%	18.3%
95% Confidence Interval	-36.0% to 45.2%	-31.1% to 40.7%
(1952-2008)		
Canada	**2.30%**	**2.00%**
Geometric Standard Deviation	19.6%	17.6%
95% Confidence Interval	-36.1% to 40.7%	-32.5% to 36.5%
U.S.	**3.60%**	**3.90%**
Geometric Standard Deviation	21.1%	18.8%
95% Confidence Interval	-37.8% to 45.0%	-32.9% to 40.7%

57.2 Please update Table 7 to also report standard deviations of the annual returns and the resulting 95 percent confidence interval around the point estimates for the average market returns.

Response:

Updated Table 7 follows.

Table 7

	Canada			U.S.		
	1924-2008	**1947-2008**	**1952-2008**	**1926-2008**	**1947-2008**	**1952-2008**
Arithmetic Averages						
Equity Market Return	**11.30%**	**11.60%**	**10.80%**	**11.70%**	**12.20%**	**11.80%**
Standard Deviation	18.77%	17.00%	16.80%	20.56%	17.66%	18.10%
95% Confidence Interval	-25.5% to 48.1%	-21.7% to 44.9%	-22.1% to 43.7%	-28.6% to 52.0%	-22.4% to 46.8%	-23.7% to 47.3%
Geometric Averages						
Equity Market Return	**9.60%**	**10.30%**	**9.40%**	**9.60%**	**10.70%**	**10.20%**
Geo. Standard Deviation	19.5%	17.3%	17.30%	22.1%	18.3%	18.80%
95% Confidence Interval	-28.6% to 47.8%	-23.6% to 44.2%	-24.5% to 43.3%	-33.7% to 52.9%	-25.2% to 46.6%	-26.6% to 47.0%

57.3 Please add the time period 1952-2008 to Tables 6 and 7 (to account for a potential effect of the monetary policy change that occurred in 1952).

Response:

Please refer to the responses to BCUC IRs 1.57.1 and 1.57.2.

57.4 Please also add to Tables 6 and 7 estimates of means and standard deviations of stock returns and resulting risk premia based on geometric averages of stock returns in addition to the arithmetic averages already employed.

Response:

Please refer to the responses to BCUC IRs 1.57.1 and 1.57.2.

57.5 Please also do all of the above for Tables 9 and 10 on pages 62 and 63.

Response:

Please see the following table containing the requested information for Table 9. Table 10 represents Ms. McShane's estimates of the risk premiums for each test that she performed and the results would not change based on the information provided in response to BCUC 57.1 to 57.5.

Table 9

	Utility Equity Returns	Bond Total Returns	Bond Income Returns
	Arithmetic Returns		
Canadian Utilities	**12.00%**	**7.90%**	**7.80%**
Standard Deviations	15.90%	10.10%	3.00%
95% Confidence Interval	-19.2% to 43.2%	-11.9% to 27.7%	1.9% to 13.7%
U.S. Gas Utilities	**12.10%**	**6.60%**	**6.00%**
Standard Deviations	15.20%	10.40%	2.60%
95% Confidence Interval	-17.7% to 41.9%	-13.8% to 27.0%	0.9% to 11.1%
U.S. Electric Utilities	**10.80%**	**6.60%**	**6.00%**
Standard Deviations	17.00%	10.40%	2.60%
95% Confidence Interval	-22.5% to 44.1%	-13.8% to 27.0%	0.9% to 11.1%
	Geometric Averages		
Canadian Utilities	**10.80%**	**7.40%**	**7.80%**
Geometric Standard Deviation	15.93%	9.60%	2.80%
95% Confidence Interval	-20.4% to 42.0%	-11.4% to 26.2%	2.3% to 13.3%
U.S. Gas Utilities	**11.00%**	**6.1%**	**6.0%**
Geometric Standard Deviation	14.60%	9.9%	2.5%
95% Confidence Interval	-17.6% to 39.6%	-13.3% to 25.5%	1.1% to 10.9%
U.S. Electric Utilities	**9.50%**	**6.1%**	**6.0%**
Geometric Standard Deviation	16.90%	9.9%	2.5%
95% Confidence Interval	-23.6% to 42.6%	-13.3% to 25.5%	1.1% to 10.9%

57.6 Please clarify, from the perspective of standard financial economics and not from the perspective of precedent ruling of regulatory tribunals, why one should prefer to use arithmetic averages rather than geometric.

Response:

Pages B-13 to B-19 contain a full explanation from the perspective of standard financial economics.

57.6.1 Does Ms McShane agree that arithmetic averages are often preferred when comparing potential returns across potential future economic "states", as when pricing an option with a binomial tree (akin to the cross-state tree example in Appendix B)? For example, starting from today and looking one year forward one might say there is an equal chance a stock's price will double in value (i.e., rise from $100 up to $200) or loses half its value (i.e., from $100 down to $50). The arithmetic average of +100 percent and -50 percent is +25 percent and thus on average we expect our wealth to grow by 25 percent, and indeed this is the average outcome (on average the price grows by [$100 - $50]/2 = $25 for an expected price of $125, which is a +25 percent growth and thus the arithmetic average is correct in this cross-state example).

Response:

Yes.

57.6.2 Does Ms. McShane agree that when using historical time-series data on returns one links returns in a sequence over time, which is a different exercise than comparing potential returns across states at a single point in time? For example, if in the first six months of the year a stock price rises by +100 percent (i.e., from $100 to $200) and then over the next six months falls by 50 percent (from $200 down to $100) the return over the year is 0 percent (since the price begins and ends at $100) which is the geometric return; the annual return is not the arithmetic average of +25 percent (which would imply an end-of-year price of $125 rather than the $100 that actually occurs). Thus, is it not the case that the geometric average is usually considered more appropriate in time-series investigations in financial economics? If Ms. McShane disagrees, please provide the rationale for the disagreement.

Response:

Ms. McShane agrees that geometric averages are used for purposes of investigating what historical performance has been.

57.6.3 At page 49 Line 1209 asserts that using geometric averages removes uncertainty from the data.

57.6.3.1 What is the meaning of the word "uncertainty" in this context?

Response:

It means the volatility of the returns during the period over which those returns are being measured. If, for example, we have two portfolios with the same beginning and ending value, the geometric average will be the same for both, irrespective of how volatile the returns of the two portfolios were over the period of measurement.

57.6.3.2 Since historical returns are observed, and are thus known for certain, is it not the case that there is no uncertainty (i.e. things unknown) whether geometric or arithmetic averages are employed?

Response:

Yes. However, there is uncertainty in future returns which must be reflected in the expected value. Please see response to BCUC 1.57.6.3.3 below.

57.6.3.3 In Ms. McShane's view, can one not more appropriately capture a notion of non-constancy (which may be what is meant by uncertainty in this context) by estimating the volatility (i.e. standard deviation) of the raw annual returns?

Response:

One can capture a notion of non-constancy by measuring the volatility of past returns, but then what is required is a translation of that non-constancy into an expected value of the return. The arithmetic average does this directly.

57.6.3.4 Please confirm that under the geometric measure this volatility is not zero and it is also not zero under the arithmetic measure; and therefore either method can be used in this specific context to capture the volatility. Is it not true that the arithmetic measure is not doing something that the geometric measure cannot also accomplish, and potentially, more accurately.

Response:

While one may be able to calculate standard deviations from the geometric series, the standard deviations themselves cannot be translated into return requirements or expectations. Given two return series with the same geometric average return and two very different geometric standard deviations, using the geometric averages for both as estimates of the expected value of the return in a cost of capital estimate understates the risk that was associated with the series with the higher standard deviation. Using the arithmetic average will capture the differential risk.

57.6.4 Please confirm that, under either the arithmetic and geometric measures, when the expanded Table 6 reports the "average", this means the average of the annual risk premia (i.e. calculate a risk premium for every year first, then take the average over time and also estimate the time-series volatility - i.e., standard deviation of the annual averages).

Response:

When calculated using arithmetic averages, the "average" risk premium is the same whether calculated by calculating each annual difference between the equity and bond returns and averaging those differences or by calculating the average equity return and the average bond return and calculating the difference between the two averages. The geometric average returns were calculated by creating a wealth index from annual return values for each data series and then the beginning and ending values of each index were used to calculate the average equity and bond returns. The geometric average risk premium was calculated as the difference between a single geometric average equity return and a single geometric average bond return. Individual years' risk premiums were not calculated. The geometric standard deviation of the risk premiums was estimated by taking the square root of the sum of the geometric variances of the annual returns for each series minus twice the covariance of the annual returns for the two series.

58.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, p. 51 Ex-Post vs. Ex-Ante Premia

In several places in the Opinion, including in lines 1273-1278, expectations of future returns and risk premia are obtained directly from past returns and equity premia without adjustment.

58.1 Does Ms. McShane agree with recent financial research results that suggest that the ex-post equity risk premium (i.e., the return investors have historically earned on risky stocks in excess of risk free bonds [where the term "risk free" in this context implies zero credit risk]) substantially over-estimates the equity risk premium investors require ex-ante (i.e., the future return they think they will receive at the time they invest), because of survivorship biases and other factors in the standard data and estimation procedures? Please explain your rationale.

<u>Response:</u>

No. The recent studies to which the question refers presumably include some which excluded consideration of the "tech wreck" in 2001/2002; none of the financial research is likely to have considered the impact of the current financial crisis on either historic results or investors' required rates of return going forward. With respect to studies which concluded that historical equity returns are not sustainable in the future because the historic values were achieved through an increase in the price/earnings ratios, please see Ms. McShane's evidence at B-16 to B-19. Several studies look at much older U.S. data, i.e., data going back to the 1800s in drawing their conclusions. The data from the 1800s are not reliable for the purpose of drawing conclusions regarding future risk premiums due to (1) dominance of a few railroads and banks in the data sets; (2) the data collected for a considerable portion of the 1800s excludes dividends; and (3) the distinctions between debt and equity that exist today were not as clear as they now are.

With respect to survivorship bias specifically, the study entitled Dimson, March and Staunton, "Risk and Return in the 20th and 21st Centuries", *Business Strategy Review*, Volume 11, Issue 2, 2000, concluded that earlier studies of historic returns suffer from survivor bias, that is, the data used to conduct analyses of the market return and market risk premiums in previous studies were (1) constructed with hindsight and excluded sectors of the market that have since disappeared, and (2) that previous studies focus on the second half of the 20th century, during which the equity market performed better relative to the first half of the century. Despite Dimson's *et al* reliance on data designed to eliminate survivor bias, the article shows a equity market risk premium in relation to bonds for the U.S. covering the period 1900 to 2000 of 7.2% (equity market return of 12.2% and a bond return of 5.0%).

Moreover, despite Dimson's *et al* concerns that previous studies focused on the second half of the century, Ms. McShane's Schedule 8 show that the most significant difference between the results for the post-World War II period compared to results which include pre-World War II data is due to the difference in bond returns between the two periods, rather than differences in equity market returns. Ms. McShane's evidence at pages B-15 to B-16 discusses the impact of the differences between the higher historic bond returns relative to expected values on the expected equity market risk premium.

A second study which dealt with survivorship, William Goetzmann and Philippe Jorion, *A Century of Global Stock Markets*: Working Paper 5901, National Bureau of Economic Research, 1997, concluded that the U.S. equity risk premium was overstated by 60 basis points, but the data employed did not take dividend income into account.

58.2 In light of this, what downward adjustments might be appropriate to the market equity premium estimates in the Opinion?

Response:

Ms. McShane does not believe that any downward adjustments to the estimated market equity risk premium are warranted.

59.0 Reference: Exhibit B-1, Tab 3, Opinion of Ms. McShane p. 52 & Tab 4 p. 23 Written Evidence of Dr. Vander Weide

At page 52 line 1284, Ms. McShane states that market risk premium result needs to be adjusted to recognize the relatively lower risk of utilities. Tab 3 Schedule 10 presents the calculations of standard deviations of monthly total market returns for each of the 10 major Sectors of the S&P/TSX Index over five-year periods ending 1997 through 2008.

At pages 23 and 24 of 87 of Mr. Vander Weide's evidence, he concludes that the Canadian utility stocks have approximately the same risk as the Canadian stock market as a whole.

59.1 Please reconcile the above two statements.

Response:

There is nothing to reconcile. The testimonies of Ms. McShane and Dr. Vander Weide provide evidence that: (1) the relative risk of Canadian utilities is higher than the "raw" betas of those utilities would imply; and (2) the relative risk of Canadian utilities is higher than the beta implied by the existing automatic adjustment formulas in Canada, including the BCUC AAM.

60.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, pp. 54-55 Multi-Factor Beta

Line 1349 reports regression results which are discussed in lines 1351-1359. Please clarify the interpretation of these results, in particular:

60.1 Please confirm that the R-squared of 43 percent means that the right hand side (i.e. independent) variables explain 43 percent of the movement in the left hand side (i.e. dependent) variable.

Response:

Confirmed.

60.2 Please describe the functional form and clarify the meaning of the regression coefficients. Do they not mean that the level of the return on the TSX Utility Index is estimated as equal to 0.185 percent plus 42 percent of the level of the return on the TSE (stock) Composite plus 53 percent of the level of the Long Bond Yield?

Response:

The regression is a time series regression for which the monthly observations of the dependent variable (utility stock returns) and the independent variables (equity market composite and long-term Canada bond) are the monthly total returns, taken from the total return indices published by the TSX in the case of the equities, and calculated for the bond as the coupon expressed on a monthly basis plus the change in price. The regression coefficients of the equity market composite and the Long-term Canada bond represent the relationship between the monthly returns for the utility index and the equity market composite and the long-term Canada bond return. As indicated in the preamble to the question, the regression means that, on average, the monthly equity return of the utility index was 42% of the return of the equity market composite plus 53% of the return on the long-term Canada bond plus 0.185%.

60.2.1 How then can this regression be used to conclude that utility shares have over 50 percent of the volatility of the Long Bond yield?

Response:

As described in response to BCUC IR 1.60.2, the regression was performed by regressing the monthly returns on the utility index against the monthly returns on the equity market and the monthly returns on the long-term Canada bond. The returns themselves include the monthly change in prices for the equity indices and the long-term bond. The monthly changes in price reflect the volatility of the variables. More precisely, the regression coefficients measure the extent to which the dependent variable co-varies with the independent variables.

61.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, p. 56 Adjusted Betas

61.1 Please identify the "Canadian Utilities" in Table 8.

Response:

Canadian Utilities refers to the company, Canadian Utilities Limited.

62.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, p. 58 DCF Based Equity Premium Test

Ms. McShane opines at page 58 that the 13 U.S. utilities are reasonable proxies for estimating the cost of equity of TGI.

62.1 Please provide details on each of the 13 utilities: (a) whether they are gas or electric, (b) are they LDCs, (c) which ones have non-regulated business, (d) which ones have risk reduction deferral accounts, sales and weather normalization features, commodity cost risk adjustment, investment prudency protection, and (e) the frequency of ROE setting and when their ROEs were last set.

<u>Response:</u>

The following table indicates for each company the type of utility, the weather and sales normalization features, whether there is commodity cost recovery, a list of the other major deferral accounts and risk mitigation mechanisms, and the date of the most recent ROE determination. Recovery of costs for all of the utilities is subject to the standard of prudency. The utilities do not have any prescribed schedule for rate reviews; except where they are subject to a rate freeze, utilities have the flexibility to apply for new rates as they deem warranted.

BENCHMARK SAMPLE OF U.S. GAS AND ELECTRIC UTILITIES

Company	Type	Type	Sales and Weather Normalization Features	Commodity Cost Recovery Assurance	Other Risk Reduction Mechanisms	Last ROE Setting
AGL Resources	Gas	LDC	Straight fixed variable rate (Georgia); Decoupling (Virginia); Weather Normalization (New Jersey and Tennessee)	Yes for all but Georgia where the company does not sell gas	Rider for Pipeline Replacement Costs (Georgia); rider for Environmental remediation liabilities (Georgia)	2005 (Georgia)
Consolidated Edison	Electric/Gas	LDC	Revenue Decoupling (electric); weather normalization (gas)	Yes (gas and electric)	True ups for OPEBS and environmental remediation expenses	2008
Dominion Resources	Electric/Gas	Vertically integrated and LDC	Straight fixed variable (Ohio)	Yes	Legislation allows for rate adjustment clauses for environmental compliance costs, FERC approved transmission rates, conservation and energy efficiency programs	1994 Virginia; 2008 Ohio
Duke Energy	Electric/Gas	Vertically integrated and LDC	Straight fixed variable rate (gas Ohio)	Yes	storm cost deferral, demand side management cost deferral, RTO cost deferral; pension expense deferral	2008
FPL	Electric	Electric Distribution		Yes	Rate Riders for generation construction costs including pre-construction costs; securitized storm recovery costs;deferral for pension expense	1990
New Jersey Resources	Gas	LDC	Decoupling	Yes	Deferrals for universal service fund; environmental remediation expenses; post retirement benefits;conservation incentive program	2008
Northwest Nat. Gas	Gas	LDC	Decoupling (Oregon)	Yes	deferral for pipeline integrity management program; pension expense deferral; environmental cost deferral	2008
NSTAR	Electric/Gas	LDC	Generic order issued for gas and electric permitting development of plans	Yes	provision for goodwill recovery;deferral for pension expense	2005
Piedmont Natural Gas	Gas	LDC	weather normalization;Customer utilization tracker (gas, NC)	Yes	deferrals for pension and retirement benefits expense, environmental remediation, demand side management; pipeline integrity expense; uncollected gas costs	2008
Scana	Electric/Gas	Vertically integrated and LDC	Weather normalization (gas, SC); Customer utilization tracker (gas, NC)	Yes	CWIP in rate base; storm damage reserve; deferrals for pension and employee benefit expense;environmental remediation expense; planned major maintenance	2007
Southern Co.	Electric	Vertically Integrated		Yes	CWIP in rate base (Georgia); storm damage reserve;deferrals for pension and employee benefit expense, plant outage costs, environmental remediation costs	2007
Vectren	Gas/Electric	LDC and Vertically Integrated	Straight fixed variable rate design (gas, Ohio); weather normalization (Indiana);	Yes	Employee benefit deferral; deferrals for demand side management expense and pipeline integrity expense	2009
WGL Holdings Inc.	Gas	LDC	decoupling (MD); declining block structure (VA)	Yes	trackers for pension and OPEB expenses	2007

Note: All companies collect income taxes on a normalized basis

63.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, p. 63 DCF Test

63.1 Ms McShane states that the DCF test is the principal model utilized in the US. Which Canadian jurisdictions have also adopted it as the principal model? In what jurisdictions have Canadian regulators rejected or minimized the DCF model? Please provide the details.

Response:

Ms. McShane is not aware of any jurisdictions that have adopted it as the principal model. The BCUC gave weight to Ms. McShane's DCF test results in its March 2006 Decision (page 55). In the last two decisions in which the Newfoundland regulator fully considered the various cost of equity tests (1998 and 2003), it determined that it would give principal weight to the equity risk premium tests. The most recent decision on ROE (December 2007) was a settlement which did not address any of the various tests. To Ms. McShane's knowledge the Nova Scotia UARB has not taken a position on the DCF test or to the other tests used to estimate the cost of equity. In the most recent completed proceeding before the Régie de l'Énergie (for Gaz Metro) on ROE (Decision dated October 2007), the DCF test does not appear to have been one of the models which was applied by the experts in that case. In its Generic Cost of Capital Decision 2004-052, the predecessor to the AUC placed no weight on the DCF results presented in that proceeding. In its most recent decision on cost of capital (for Ontario Power Generation dated October 2008), the Ontario Energy Board determined that one could not rely wholly on DCF and that the equity risk premium test is the most reliable test upon which to base its determinations. The NEB did not rely on the DCF in its March 2009 decision.

63.2 Is the use of 'analysts forecast' not a significant flaw that would affect the confidence one could place on the DCF model?

Response:

No, Ms. McShane does not view the use of analysts' forecasts as a flaw. It is true that, as with all of the other tests used to estimate the cost of equity, some of the key inputs must be inferred. In the application of the DCF test, investors' growth expectations must be inferred. The financial research supports the conclusions that analysts' forecasts are superior predictors of future growth rates than historical growth rates and, when actual earnings are properly measured, analysts' forecasts of earnings growth are unbiased. As with any test used to estimate the cost of equity, there is bound to be measurement error. It is precisely for that reason analysts and regulators need to apply multiple tests and judgment when arriving at the cost of equity and a fair return.

64.0 Reference: Exhibit B-1, Tab 2, Opinion of Ms. McShane, pp. 66, 67 Flexibility Factor

Pages 66 to 67 and Appendix E discuss the need to add an extra return component to the base ROE in order to account for a financial flexibility factor.

64.1 Is it not the case that the required market return on a share of some arbitrary company's stock should already contain the return investors require for financial flexibility and indeed for all other risk factors? If not, do you agree then that some risk that should be priced is not being priced in the market? In your view, would this have violated standard finance?

Response:

The financing flexibility adjustment includes cost factors which are not by their very nature contained in the required market return as estimated using the market-derived tests, i.e., costs of raising new equity (out of pocket financing costs and market pressure). With respect to the remainder of the 0.50% increment for financing flexibility, it is the distinction between the manner in which the returns are derived (on market values) and the manner in which they are applied (to book values) which results in the need for a financing flexibility adjustment. The application of a return estimated on the basis of market values and applied to book values implies a market value just equal to book value. In this regard, please note the conclusion drawn by the Independent Assessment Team in their review of the cost of capital for the Alberta Power Purchase Arrangements referenced at page E-2 of Ms. McShane's testimony. "This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada." The adjustment to the market derived cost for financing flexibility rate provides a minimal increment to preserve financial integrity (i.e., market price slightly in excess of book value).

64.2 If yes, then if one estimates the ROE required for TGI using data on stock returns of other companies (that already contain compensation for a flexibility factor), then why does the calculated ROE for TGI require an additional adjustment for a flexibility factor? Why does this not result in double-counting?

Response:

Please see response to BCUC 1.64.1.

64.3 Lines 1679 to 1680 on page 67 states that "a financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis point". Please provide the monthly market to book ratios of Canadian gas utilities from September 2006 to July 2009.

Response:

There are only two Canadian gas utilities which are publicly traded, Gaz Metro LP and Pacific Northern Gas. The requested monthly market to book ratios through June 2009 are presented in the table below.

	Gaz Metro LP	PNG		Gaz Metro LP	PNG
Sep06	2.20	0.81	Feb08	2.02	0.81
Oct06	2.28	0.86	Mar08	2.03	0.80
Nov06	2.08	0.85	Apr08	1.93	0.80
Dec06	1.99	0.84	May08	2.01	0.81
Jan07	2.08	0.82	Jun08	2.02	0.80
Feb07	2.17	0.82	Jul08	1.91	0.75
Mar07	2.19	0.81	Aug08	1.97	0.73
Apr07	2.16	0.81	Sep08	1.94	0.74
May07	2.18	0.81	Oct08	1.72	0.71
Jun07	2.20	0.81	Nov08	1.75	0.67
Jul07	2.22	0.81	Dec08	1.55	0.58
Aug07	2.14	0.82	Jan09	1.68	0.58
Sep07	2.15	0.82	Feb09	1.75	0.55
Oct07	2.07	0.83	Mar09	1.63	0.52
Nov07	2.01	0.83	Apr09	1.72	0.53
Dec07	1.97	0.84	May09	1.72	0.61
Jan08	1.99	0.81	Jun09	1.74	0.67

65.0 Reference: Exhibit B-1, Opinion of Ms. McShane, pp. 63-66 DCF Model Robustness

Appendix D details the DCF model employed to estimate the cost of equity, results from which are employed in the body of Ms. McShane's Opinion.

65.1 How robust are the estimates of "k", the cost of equity, with respect to a variety of reasonable changes in data and time periods?

Response:

Please see response to BCUC 1.65.3.1.

65.1.1 For example, one could vary the estimate of "g" and "D" by changing data windows or assumptions used to estimate "D" and "g". How sensitive is the cost of equity to the assumptions used regarding these inputs into the DCF model? Please provide the data and the results of the analysis to support your answer.

Response:

Please see response to BCUC 1.65.3.1.

65.2 The DCF model requires a price "P" to be specified. Is it true that, all else being equal, the lower the price "P", the higher the cost of equity (called "k") by construction?

Response:

By construct, *ceteris paribus*, a decline in the value of "P" would result in an increase in the estimated value of "k". Similarly, a cut in dividends or the expected growth rate, absent a change in "P", would result in a decrease in the estimated value of "k". While changes in price are immediate, changes in price do not occur in a vacuum. As economic circumstances change, whether related to a particular company or on an industry-wide or global basis, analysts, companies and investors respond by modifying their growth forecasts.

65.3 Is it not the case that the stock market was significantly below its trend at the time Ms. McShane's Opinion was written and thus that the value of "P" employed might have been lower than the value of "P" would be using other potential time periods?

Response:

Confirmed that the market composites in Canada and the U.S. are currently higher than their average during the January to March period for which the DCF costs for the utilities were estimated. However, the prices for the utility sample were less than 0.50% higher in June 2009 than they were on average during the January to March period.

65.3.1 For example, please use the average "P" over the past year, and use the value of "P" as of July 2009, and report on the sensitivity of the results regarding the estimate of "k". How robust is the estimate of "k"?

Response:

As changes to "P" do not occur in a vacuum, i.e., growth forecasts change as well as price, the DCF costs of equity presented in Schedules 16 and 17 were re-estimated using average data (price, growth forecasts and dividend) over the past year as well as for the most recent month ending June 2009. An expanded version of Table D-1 including these results is presented below. The reported standard deviation is for the estimated costs of equity for the companies in the sample. The individual point estimates are included in Attachment 65.3.1.

Based on the most recent data, the estimated "bare-bones" return on equity derived from the constant growth DCF model is virtually identical to the 11.0% estimated by Ms. McShane at the time her evidence was filed (see page D-5).

Table D-1 Expanded

Earnings Growth Forecast		**Average**	**Median**	**Std. Deviation**
I/B/E/S	Data Averaged Over Past Year	10.7	10.8	1.5
	As Filed - Schedule 16	11.0	10.9	1.8
	Most Recent Data	11.0	11.4	1.6
	Average	**10.9**	**11.0**	
Value Line	Data Averaged Over Past Year	10.9	10.5	2.2
	As Filed - Schedule 17	11.3	11.0	2.7
	Most Recent Data	10.9	10.6	1.8
	Average	**11.0**	**10.7**	

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

Company	**Dividend Paid July 2008-June 2009**	**Avg. Monthly High/Low Prices Jul 2008-Jun 2009**	**Expected Dividend Yield [1/]**	**Average I/B/E/S Long-Term EPS Forecasts Jul 2008 to Jun 2008**	**DCF Cost of Equity [2/]**
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.70	30.29	5.9	4.6	10.5
Consolidated Edison	2.35	38.95	6.2	2.6	8.8
Dominion Resources	1.67	36.01	5.0	7.8	12.8
Duke Energy	0.92	15.40	6.2	4.5	10.7
FPL	1.84	52.37	3.8	9.8	13.7
New Jersey Resources	1.21	35.02	3.7	6.4	10.1
Northwest Nat. Gas	1.56	44.84	3.6	4.8	8.4
NSTAR	1.45	32.56	4.7	6.4	11.1
Piedmont Natural Gas	1.06	27.12	4.2	7.0	11.2
Scana	1.86	33.82	5.8	5.0	10.8
Southern Co.	1.70	33.35	5.4	5.4	10.8
Vectren	1.33	24.77	5.7	6.1	11.8
WGL Holdings Inc.	1.43	32.05	4.7	4.1	8.8
Mean	**1.54**	**33.58**	**5.0**	**5.7**	**10.7**
Median	**1.56**	**33.35**	**5.0**	**5.4**	**10.8**
Standard Deviation					**1.52**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

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

65.3.2 Please demonstrate how the above would change the results of Table D-1.

Response:

Please see response to BCUC 1.65.3.1.

65.4 Please provide standard deviations along with point estimates when reporting results from the foregoing estimations.

Response:

Please see response to BCUC 1.65.3.1.

66.0 Reference: Exhibit B-1, Opinion of Ms. McShane, pp. 67-72 Comparable Earnings Test

66.1 Do any Canadian regulators support the use of the Comparable Earnings Test? Which ones and how do they use the results?

Response:

As noted in Ms. McShane's evidence at page F-6, in arriving at its decision for TGI and TGVI in March 2006, the British Columbia Utilities Commission stated that it did not believe comparable earnings had outlived its usefulness, and that it may yet play a role in future ROE hearings. It also concluded that that there was insufficient evidence before it regarding whether or not a market/book ratio adjustment was merited and, if so, how it might be accomplished. Ms. McShane provided a full discussion on the merits of a market/book adjustment in her evidence in this proceeding and concluded that there was no reason to make such an adjustment. To Ms. McShane's knowledge, although other Canadian regulators have supported the use of the comparable earnings in the past (i.e., Alberta, Ontario), there have been no other decisions within the past 10 years which have supported the use of the comparable earnings test as applied in this proceeding. In its recent TQM decision, the NEB placed some weight on the litigated returns of U.S. utilities, which is effectively a form of comparable earnings.

66.2 For the 27 comparable companies identified on Schedule 19, please compare each of their risk profiles to TGI. Please show the derivation of the 75-100 basis point risk adjustment and the statistical validity to the adjustment.

Response:

Ms. McShane has not done a qualitative assessment of the business risks of each of the 27 companies identified on Schedule 19. To select companies of relatively similar risk to a utility, as noted on page F-1, "As a point of departure, the selection was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility." The risk statistics for the individual companies are found on Schedule 20. The 75 to 100 basis point reduction to the ROEs of the unregulated companies reflects as noted in footnote 28:

(1) the typical spread between the yields on long-term BBB rated industrial bonds (since the non-regulated companies have an average debt rating of BBB to BBB (high) and the corresponding yields on A rated utility bonds (equal to the typical utility rating), estimated at 75 basis points;

(2) the differential in estimated 2007-2008 betas between the sample of unregulated companies (.71) and the samples of Canadian utilities (.59) and U.S. utilities (.65). The differential betas were applied to the premium of the sample ROEs of 12.5-12.75% over the forecast of long-term Canada bonds over the longer term of 5.25%. The lower betas of the utilities indicate a downward adjustment to the unregulated companies' ROEs of slightly less than one percentage point.

The reduction is based on two separate measures, which, to Ms. McShane's knowledge, do not lend themselves to specific tests of statistical validity.

66.3 On page 70, Ms. McShane states that the full business cycle 1991-2007 provides an appropriate proxy for the next business cycle.

66.3.1 Please provide the rationale and if alternative time periods have been explored and what the results are.

Response:

The rationale is provided at pages F-2 and F-3 of Ms. McShane's testimony. In light of prevailing recessionary conditions, Ms. McShane concluded that it was appropriate to include returns during the prior recession during 1991-1992. The use of any sub-period of 1991-2007 would have resulted in higher average returns. For example, if the period 1996-2007, which includes several years of sub-trend economic growth, had been utilized the average of annual medians ROE for the sample would have been in excess of 14% compared to the 1991-2007 corresponding value of just under 13%.

66.3.2 How were the returns on equity calculated for each company?

Response:

The annual returns were calculated as the net income available to common equity before extraordinary items divided by the mid-year average common equity.

66.4 Please identify if any companies were added or removed from the list of comparable companies in the past 10 years. If so, why were changes made? Please also comment what would be the impact if no changes were made.

Response:

A comparison of the companies included in the comparable earnings sample employed in the cost of capital proceeding for TGI in 1999 and the current proceeding shows that the following companies were included in the sample in 1999 but not in the 2009 sample: Canada Bread Ltd., Cara Operations Ltd., CCL Industries, Corby (H.)Distillery, Dover Industries Ltd., DuPont Canada, Empire Company Ltd., Imperial Oil Ltd., Oshawa Group Ltd., Quebecor Inc., Shell Canada Ltd., U A P Inc., and Winpak Ltd. Companies in the 2009 sample that were not in the 1999 sample include Astral Media Inc., Canadian National Railway Co., Canadian Pacific Railway Ltd., Cogeco Inc., Finning International Inc., Jean Coutu Group, Linamar Corp., Magna International, Maple Leaf Foods Inc., Metro Inc., Newfoundland Cap Corp., Richelieu Hardware Ltd., Saputo Inc., Shaw Communications Inc., SNC-Lavalin Group Inc., Toromont Industries Ltd., Torstar Corp., Transcontinental Inc., TVA Group Inc., and Uni-Select Inc.

A sample is the outcome or result of the application of a set of screening criteria to a universe of companies; a new sample is selected each time the analysis is done. Over time, companies are acquired and disappear; as new companies are formed they are added. A priori, it is not known which companies will be included in a particular sample. Further, the criteria for selection have been changed since 1999. In 1999, the selection criteria included coefficients of variation of returns and coefficients of variation of earnings before interest and taxes which were criticized as being biased toward selecting high earnings firms. These criteria were replaced with criteria which did not depend directly on the earnings themselves: betas, debt ratings, and stock rankings.

In addition, in 1999, the initial screen was limited to companies within particular Standard Industrial Classification (SIC) codes. The industry identification system has since changed to Global Industrial Classification Standard (GICS) codes, so these are now being used, with the objective of covering similar industries. However, the mapping between SIC and GICs codes is not precise. The integrated oil companies, for example, which were included in the 1999 sample, do not fall into a GICS code currently used for selection. The average of annual medians for both the existing sample and the 1999 sample are identical at 12.8%.

66.5 In the discussion of the 81 US comparable companies on page 71, the risk adjustment is approximately 14 percent (lines 1791-1793). Why is it a percentage for US companies and a discrete number of basis points for Canadian companies (lines 1779-1781)?

Response:

The discussion at page 71 indicates that the sample average ROE of 15.5% was reduced to 14% (i.e. by 1.5 percentage points), not by 14%.

67.0 Reference: Exhibit B-1, Tab 3, Expert Testimony of Ms. McShane p. 70

"Since the universe of Canadian unregulated companies is sufficiently large to produce a representative sample of sufficient size, the focus of the comparable earnings analysis was on Canadian firms. The application of the selection criteria to the Canadian universe produced a sample of 27 companies."

On Tab 2 page 94 of the TGI June 30, 2005 ROE Application the sample by Ms. McShane resulted in a sample of 17 companies.

67.1 Please confirm if the screening criteria in the present Application is the same as in 2005. If not explain the differences and impact on the resulting screened companies.

Response:

The screening criteria are largely the same; the only substantive difference is the removal of the 2005 criterion which eliminated companies that were plus or minus one standard deviation from the sample mean return. The criterion was removed to allow for a larger sample of companies, and the criterion itself was not necessary to ensure selection of comparable companies. The following table compares the specific criteria used in 2005 and 2009. If the criterion had been applied, the sample would have contained 16 companies rather than 27.

Criteria For Removing Companies From Unregulated Company Sample

Year of Selection	GICS Codes	Equity Data Availability	Market Data Availability	Equity Level	Shares Traded	Income Trust	Dividends Paid	CBS Stock Ranking	Debt Ratings	Betas	+/- 1 Standard Deviation From Average
2005	20-30	Missing or negative equity 1993-2003	not specified	no limits	Traded fewer than 125,000 shares in 2003	yes	No dividends paid in any year 1999-2003	Higher Risk or Speculative	Non-investment grade or no rating	Above 1.0 for December 2003	yes
2009	20-30	Missing or negative equity 1997-2007	Less than 5 years of market data	equity less than $100 million	Traded fewer than 5% of outstanding shares in 2007	yes	No dividends paid in any year 2004-2008	Higher Risk or Speculative	Non-investment grade or no rating	Above 1.0 on average for December 2007 and December 2008	no

67.2 Compare the 2009 sample to the 2005 sample and identify those companies who were in 2005 and no longer in 2009, if any, and provide financial information on these companies similar to what has been filed for the 2009 sample. Explain why these companies are no longer in the 2009 sample.

Response:

Four companies were included in the 2005 sample that are not included in the 2009 sample, Algoma Central Corp., Canada Bread Co. Ltd., Empire Co. Ltd., and Quebecor World Inc. Financial data for these companies are presented in the following table. Algoma Central and Canada Bread were removed from the universe because they traded less than 5% of their outstanding shares in 2007. Empire was removed because it was rated BB(high) by DBRS. Quebecor World was removed because its average 2007 common equity was negative.

RISK MEASURES FOR 4 LOW RISK UNREGULATED CANADIAN COMPANIES NOT INCLUDED IN 2009 SAMPLE

	Debt Ratings		CBS Stock	Beta				2007 Equity Ratio	1991-2007
				2003-2007		2004-2008		Based On	Average Market
Company Name	S&P	DBRS	Rating	Raw	Adjusted	Raw	Adjusted	Total Capital	To Book Ratio
ALGOMA CENTRAL CORP			Average	0.43	0.62	1.08	1.05	96.3%	0.98
CANADA BREAD CO LTD			Conservative	0.25	0.50	0.63	0.75	84.4%	2.16
EMPIRE CO LTD -CL A			Very Conservative	0.81	0.87	0.30	0.53	60.2%	1.42
QUEBECOR WORLD INC -SUB VTG	B+		Speculative	2.34	1.90	2.39	1.93	NMF	1.43
Mean	**B+**		**Conservative**	**0.96**	**0.97**	**1.10**	**1.07**	**80.3%**	**1.50**
Median	**B+**		**Conservative**	**0.62**	**0.75**	**0.85**	**0.90**	**84.4%**	**1.42**

Source: Standard and Poor's Research Insight, DBRS and The Blue Book of CBS Stock Reports.

67.3 Compare the 2009 sample to the 2005 sample and identify those companies who are in the 2009 sample and were not included in 2005. Please explain why these were excluded in the 2005 sample.

Response:

The following table identifies the companies and the reason they were not included in 2005.

Companies in 2009 Sample Not in 2005 Sample	
Company	*Reason*
Andres Wines	CBS Higher Risk
Astral Media	insufficient data
Canadian National Railway	+/- one standard deviation
Canadian Pacific Railway	insufficient data
Cogeco	Beta higher than 1.0
Jean Coutu	non-investment grade

Companies in 2009 Sample Not in 2005 Sample	
Company	*Reason*
Newfoundland Capital	did not pay dividends in all years
Richlieu Hardware	insufficient data
Saputo	insufficient data
Shaw Communications	+/- one standard deviation
SNC-Lavalin	Utility assets
Toromont	+/- one standard deviation
TVA	Beta higher than 1.0
Uni-Select	insufficient data

68.0 Reference: Exhibit B-1, Tab 3, Appendix A p. A-4

At page A-4, Ms. McShane commented that in the presence of inflation, even at moderate levels, absent significant technological advances, replacement cost should exceed the original cost book value of assets. Consequently, the market value of utility shares should be expected to exceed their book value.

68.1 Given the quarterly Canada and US GDP Deflator Indexes and Consumer Price Indexes for 2008 as presented in Schedule 2, does Ms. McShane believe that the two economies could have entered a period of no-inflation or deflation?

Response:

No. In this context, in its April 2009 *Monetary Policy Report*, the Bank of Canada judged that the possibility of a sustained period of deflation was remote. The April 2009 consensus forecasts for the U.S. and Canada indicate that economists anticipate CPI inflation to average 2.3% and 2.1% respectively from 2010 to 2019. The comparative CPI rates of inflation over the 10-year period ending 2008 were 2.8% and 2.3%.

68.1.1 In Ms. McShane's view, has the likelihood that market value of utility shares to exceed their book value decreased?

Response:

No, on the basis of the premise discussed in the preamble to the question, that is, in the presence of inflation, even at moderate levels, absent significant technological advances, replacement cost should exceed the original cost book value of assets.

68.1.2 Please provide an update to the above indexes for Canada and the US for the first two quarters of 2009.

Response:

The requested second quarter data are not currently available. The following table presents data for the first quarter of 2009 for the Canadian and U.S. GDP deflator indices (U.S. Implicit Price Index) and monthly data through May for the Canadian and U.S. Consumer Prices Indices.

	Canada		**U.S.**	
	Consumer Price Index	**GDP Deflator Index**	**Consumer Price Index**	**Implicit Price Index**
Jan-09	151.1		170.3	
Feb-09	152.2		171.1	
Mar-09	152.4		171.5	
Q1 2009	**151.9**	**147.3**	**171.0**	**158.0**
Apr-09	152.3		172.0	
May-09	153.4		172.5	

69.0 Reference: Exhibit B-1, Tab 3, Opinion of Ms. McShane Charts and Schedules

69.1 Chart 1 (preceding Schedule 1) shows the performance of the S&P/TSX Composite and the S&P/TSX Utilities since 1988. Please show the TSX Utilities indices disaggregated by company. Please also create a similar chart with total returns, including stock price change plus dividends and reinvestment of dividends.

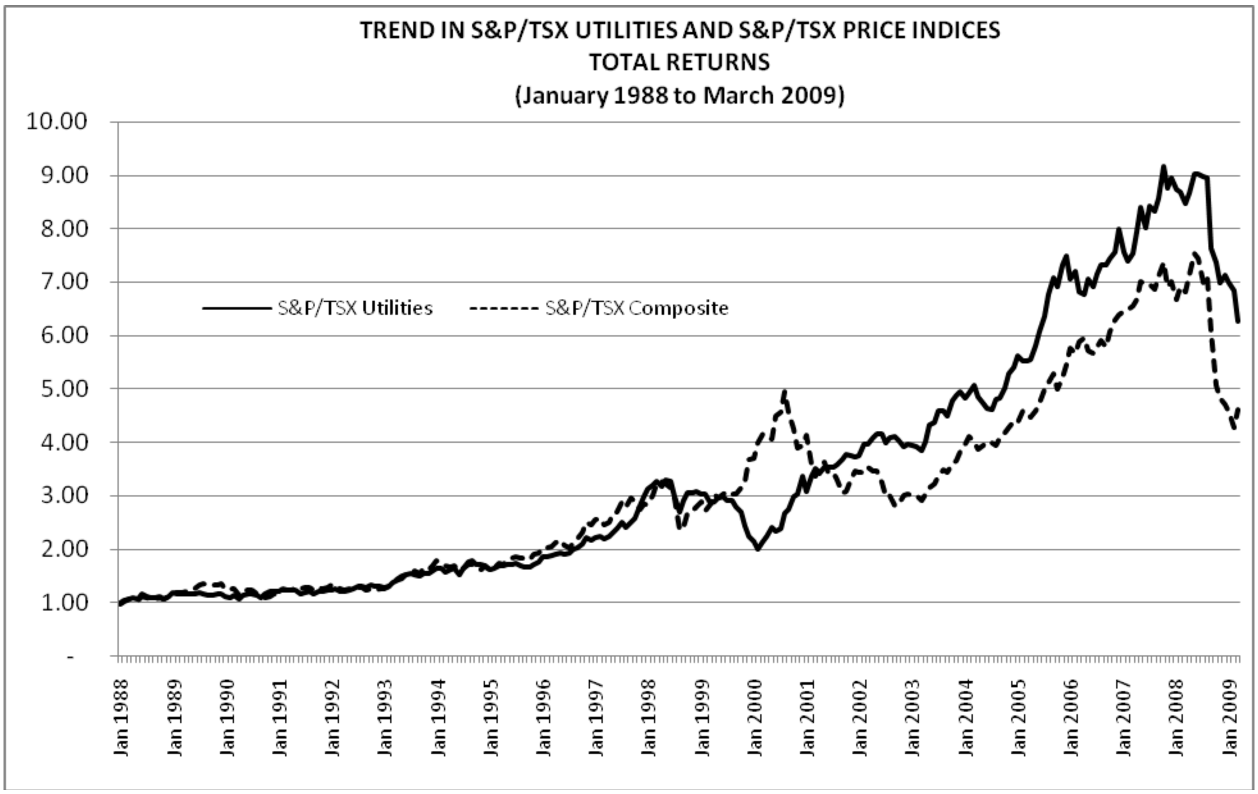
Response:

Ms. McShane has not compiled the data which would permit the disaggregation of the index by company. Note that the index has not always included the same companies. Some have disappeared due to acquisition (i.e. Terasen Inc. and Westcoast); some have been moved to other indices (i.e. Enbridge and TransCanada) and some have been added during the time frame in question (i.e. Northland Power). Ms. McShane has however calculated the total returns for the individual companies which appear on page 11, page 3 of 3 for the period in question. These returns appear in the table below.

	CANADIAN UTILITIES	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP
1988	6.4%		5.4%	12.5%	19.4%	19.8%	0.0%
1989	20.7%		7.2%	19.3%	10.3%	24.7%	18.2%
1990	-0.1%		13.2%	3.5%	2.2%	2.3%	4.1%
1991	9.1%		-28.0%	17.7%	28.6%	22.9%	7.4%
1992	5.8%		-4.0%	9.7%	27.9%	-8.8%	5.3%
1993	32.8%	28.9%	50.4%	24.0%	39.8%	19.5%	19.2%
1994	-0.6%	-8.7%	-5.5%	-4.5%	-3.9%	-13.8%	-10.2%
1995	15.2%	19.0%	19.4%	12.8%	8.7%	26.1%	16.5%
1996	23.8%	23.3%	32.7%	32.2%	11.3%	33.4%	33.9%
1997	39.0%	28.1%	71.1%	29.9%	39.2%	42.6%	38.7%
1998	22.6%	9.4%	11.7%	-4.9%	-4.4%	13.8%	-26.5%
1999	-15.4%	-17.0%	-15.7%	-13.6%	-32.8%	-13.1%	-40.6%
2000	36.8%	30.3%	58.5%	21.5%	-52.5%	37.1%	46.4%
2001	1.2%	-0.6%	2.7%	36.8%	20.8%	3.4%	20.9%
2002	6.6%	0.9%	1.5%	16.3%	84.9%	19.3%	20.6%
2003	17.3%	17.1%	30.5%	16.4%	15.0%	30.2%	27.1%
2004	8.2%	12.7%	15.1%	22.2%	11.9%	19.5%	11.4%
2005	50.4%	15.1%	25.5%	43.7%	-2.6%		27.6%
2006	12.3%	12.3%	14.3%	26.0%	-3.5%		14.9%

	CANADIAN UTILITIES	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP
2007	-0.2%	1.1%	2.7%	0.4%	8.5%		3.5%
2008	-10.0%	5.9%	2.0%	-12.0%	-23.8%		-15.0%

A chart showing the total return indices for the Utilities Index and the S&P/TSX Composite from 1988 to 2008 is provided below.



69.2 Schedule 5 shows the financial metrics of Canadian utilities. Please show the impact that a 40 percent equity ratio and a ROE of 11 percent would have on TGI's financial metrics.

Response:

The approximate impact of 40% deemed equity ratio and ROE of 11% will have on TGI's financial metrics per Schedule 5 is as follows:

	EBIT Coverage	FFO/Total Debt	FFO Coverage
TGI	2.5x	11.9%	2.8x

69.3 Schedule 10 provides the standard deviations of market returns for TSX indices. The utilities data appear extremely volatile but seems to indicate an average beta of about 0.4. Is there any statistical confidence in the utilities betas?

Response:

The table below shows the R^2s, t-statistics and standard errors for each of the utility index betas shown on Schedule 10, page 2 of 2. Over the full period for which the betas have been provided, the betas exhibit relatively low statistical significance i.e. low R^2s and low t-statistics, particularly for the betas ending 1999 through 2006.

5 Year Price Betas for S&P/TSX Utility Index				
	Beta	***R^2***	***T-Statistic***	***Standard Error***
1997	0.53	0.370	5.8394	0.0915
1998	0.55	0.465	7.0974	0.0779
1999	0.30	0.130	2.9470	0.1019
2000	0.14	0.025	1.2101	0.1153
2001	-0.03	0.001	-0.2799	0.1128
2002	-0.06	0.005	-0.5257	0.1088
2003	-0.25	0.079	-2.2381	0.1136
2004	-0.13	0.023	-1.1652	0.1141
2005	0.00	0.000	-0.0244	0.1077
2006	0.25	0.068	2.0535	0.1217
2007	0.46	0.143	3.1123	0.1487

5 Year Price Betas for S&P/TSX Utility Index				
	Beta	***R^2***	***T-Statistic***	***Standard Error***
2008	0.49	0.281	4.7636	0.1024

69.4 Schedule 11 shows the S&P/TSX composite sector compound returns and betas. Throughout the various time periods, the Pipelines and Utilities compound returns are near the top of the sub-indices. Why would this be the case when their betas are lower than the other sub-indices?

<u>Response:</u>

There are two possible inter-related reasons: (1) Betas and actual returns do not reflect the relationship that would be expected *a priori* and (2) If riskier stocks always earned higher returns, they would not necessarily be viewed as risky.

WRITTEN EVIDENCE OF DR. VANDER WEIDE

70.0 Reference: Exhibit B-1, Tab 4 Written Evidence of Dr. Vander Weide, pp. 9-10
Risk and Volatility

70.1 Lines 14-16 on p. 9 refer to "comparable risk". Exactly and specifically, what risks are comparable and worthy of consideration?

Response:

The phrase on page 9, lines 14 – 16, of Dr. Vander Weide's written evidence is a paraphrase of the fair return standard enunciated by the three Supreme Court cases cited on page 7, lines 22 – 25. These cases do not define "exactly and specifically" the risks that should be considered in assessing whether a return is fair. However, from an economic perspective, it is only important that the overall risk of the comparable companies be similar to the risk of the company whose rates are being determined. Furthermore, one must recognize that are no companies that are perfectly comparable in risk to a target company. Thus, the analyst necessarily must choose a set of companies that are most comparable in overall risk to the utility whose rates are being set. For the reasons explained in his written evidence, Dr. Vander Weide believes that his two comparable groups of Canadian utilities and his two comparable groups of U.S. utilities are sufficiently comparable in overall risk to provide valuable information regarding the fair return for TGI.

70.2 Lines 15-19 on page 10 as well as other places in the Evidence including page 24 lines 7-9 consider the volatility of returns.

70.2.1 Is volatility of return the same as risk?

Response:

In theory, volatility is not exactly the same as risk. As noted in response to BCUC IR 1.14.5 and BCUC IR 1. 14.5.1, however, the average investor considers risk to be uncertainty regarding the expected outcome. Thus, to the average investor, volatility is a reasonable measure of risk.

70.2.2 Please explain why the volatility of returns on utility stocks being higher than the volatility of the general stock market must necessarily imply that utility stocks are riskier than the market in general?

Response:

Please see response to BCUC IR 1.14.5.1 (a) and (b).

70.2.3 Under generally accepted finance theory, are stock holders compensated for: total volatility or just systematic risk that cannot be diversified (which is what is implied by standard finance theory and the CAPM, for example)? Please explain your response in detail.

Response:

Under the Capital Asset Pricing Model, stock holders are compensated only for systematic risk that cannot be diversified. However, the CAPM is a single-period model that does not necessarily describe how returns are generated in the marketplace in the long run. As discussed in response to BCUC IR 1.14.5.1 (b), systematic risk is difficult to measure for long-run investors like investors in utility stocks.

70.2.4 If systematic risk is what investors are compensated for, then why is total volatility a useful statistic to employ in its raw form? Please explain your answer.

Response:

Volatility is a useful statistic because it is consistent with the reasonable notion that risk is defined as the uncertainty about an expected value. Furthermore, volatility may be more indicative of the risk of long-run investments such as utility stocks than systematic risk as measured by beta. As discussed in response to BCUC IR 1.14.5.1 (b), systematic risk as measured by beta reflects the correlation between the short-run (weekly or monthly) returns on utility stocks and short-run returns on the market index. Since utility investors are long-term investors, the correlation between weekly and monthly returns on utility stocks and weekly and monthly returns on the market index is a poor indicator of systematic risk in the long run.

71.0 Reference: Exhibit B-1, Tab 4 Written Evidence of Dr. Vander Weide, p. 11
Utilities Stock Index

71.1 At lines 11 to 18 on page 11, the companies included in the S&P/TSX utilities stock index appear to be mostly electric Income Trusts. Why are these companies' returns comparable to TGI?

Response:

As explained on pages 27 – 28 of Dr. Vander Weide's written evidence, the companies in the S&P/TSX utilities stock index are not perfectly comparable to TGI. TGI is a regulated natural gas distribution utility, and there are few regulated natural gas distribution utilities that have publicly-traded stock. Recognizing the difficulties in identifying publicly-traded companies with exactly the same risks as TGI, Dr. Vander Weide examined cost of equity evidence from two groups of publicly-traded Canadian utilities, the BMO CM market basket of utilities, and the S&P/TSX utilities index, and two groups of publicly-traded U. S. utilities. The primary advantage of using the S&P/TSX utilities stock index is that there are more companies in the S&P/TSX index than in the BMO CM basket of utility stocks and return data for this index is available for a long period of time. The primary advantage of the BMO CM basket of Canadian utilities is that it only includes companies that receive a significant portion of their revenues from traditional utility operations. The primary advantages of his U.S. utilities groups are that: (1) they include a significantly larger sample of companies with traditional utility operations than Canadian groups; (2) the business risk of U.S. utilities is comparable to the business risk of TGI; (3) reasonable estimates of expected growth rates are available for U.S. utilities, whereas the same data are not available for the Canadian utilities; and (4) historical data for the U.S. utilities are available for a much greater length of time than for the Canadian utilities.

72.0 Reference: Exhibit B-1, Tab 4, Written Evidence of Dr. Vander Weide, p. 13
Calculating Returns

Line 13 calculates the annual return as: rt = (Wt/Wt-1) -1, where the time t signifies a year. In other words, the formula employed by Dr. Vander Weide steps over temporary price fluctuations that may occur within the year and compares wealth at the beginning and end of the year to calculate an annual return, as is commonly done in standard accepted finance practice.

72.1 In keeping with the spirit of how the calculation above was accomplished, how should one then calculate the return to holding stock over a longer span of time, for example a decade?

Response:

The answer depends on whether one is attempting to: (1) measure the compound return that was actually achieved during a past time period; or (2) predict the expected value of wealth at the end of a future time period. If one is simply attempting to measure the compound return that was actually achieved during a past time, then one should use the geometric mean return calculated from the formula:

$$G_m = \prod_t (1 + r_t)^{1/n} .$$

However, if one is attempting to predict the expected value of wealth at the end of a future time period, then one should use the arithmetic mean return calculated from the formula:

$$AM = \sum_t r_t / n .$$

Since the results of Dr. Vander Weide's studies are used to estimate an investor's required rate of return on future investments, the arithmetic mean return is the most appropriate return for his studies. Therefore, Dr. Vander Weide calculates the arithmetic mean return rather than the geometric mean return on his historical data sets.

Further explanation of why the arithmetic mean is required to predict the future value of wealth at the end of a future time period is contained in *Ibbotson SBBI® 2009® Valuation Yearbook Market Results for Stocks, Bonds, Bills, and Inflation 1926 – 2008*, pages 59 – 60.

72.1.1 Does Dr. Vander Weide agree with the approach where one takes wealth at the beginning of the decade and compare it to wealth at the end of the decade? In other words, apply the same formula above, rt = (Wt/Wt-1) -1, except with the span of time being 10 years instead of one year? If not, why not.

Response:

Dr. Vander Weide agrees that the approach is reasonable if one is attempting to measure the compound return that was actually received at the end of a 10-year period. Dr. Vander Weide does not agree that this is a reasonable approach to estimate the required return on a future investment. Please also see response to BCUC IR 1.72.1.

72.1.1.1 What then would be the formula average return for each year within the decade? Would it be based on the 10th root of the gross 10-year return? Is this the geometric average?

Response:

If one is attempting to measure the compound return that was actually achieved for each one-year period within a decade, then one could measure the return using the formula, $r_t = (W_t \div W_{t-1}) - 1$, where t signifies a year; or by taking the 10^{th} root of the return over a 10-year historical period. Either formula would yield the geometric average of the experienced return in the particular period. However, as noted in response to BCUC IR 1.72.1, the geometric average return would not be an appropriate estimate of the required rate of return on future investments.

72.1.2 What would happen if, instead, one estimated total return over the decade by simply summing up the 10 individual-year returns to obtain a 10-year total return estimate?

Response:

If one estimates the total return over a decade by simply summing up the ten individual annual returns, the result would be an estimate of the simple, or non-compounded, return over the ten-year period.

72.1.2.1 Will this calculation result in a total return estimate that overestimates or underestimates the return actually earned by the investor?

Response:

A calculation that estimates return by summing up the ten annual returns earned over a ten-year period will underestimate the return that was actually achieved during that past ten-year period because it does not include the effect of compounding. Please also see response to BCUC IR 1.72.1.

72.1.2.2 If we divided this total return estimate by 10 to produce an estimate of average annual return over the decade, will this average estimate therefore overestimate or underestimate the return actually earned by the investor? Is this the arithmetic average? Please explain your answer.

Response:

(a) The arithmetic mean return calculated by summing up ten annual returns over a ten-year period and then dividing this sum by ten will be larger than the geometric mean return actually earned over the ten-year period.

(b) The sum of the ten annual returns divided by ten is the arithmetic average return. Please also see response to BCUC IR 1.72.1.

72.1.3 What does the foregoing imply about the appropriateness of using geometric vs. arithmetic averages in a general finance sense when estimating average returns from a time-series of price data?

Response:

The foregoing implies that the geometric mean measures the returns actually achieved in a past period but that the arithmetic mean is the best estimate of the return investors require in the future, that is to say, the arithmetic mean return is the appropriate return for estimating the cost of equity. Please also see response to BCUC IR 1.72.1.

72.1.4 In Dr. Vander Weide’s opinion, what does the foregoing imply about using arithmetic, rather than geometric, methods when calculating time-series averages (i.e. average returns and risk premia over a span of time) in this Application?

Response:

Dr. Vander Weide’s purpose in this proceeding is to estimate the investor’s required rate of return. For this purpose, the arithmetic mean return should be used to calculate time-series averages. Please also see responses to BCUC IR 1.72 and its sub-parts.

73.0 Reference: Exhibit B-1, Written Evidence of Dr. Vander Weide, p. 14, Ex-Post vs. Ex-Ante Premia

In lines 4-6, expectations of future returns and risk premia are obtained directly from past returns and equity premia without adjustment.

73.1 Does Dr. Vander Weide agree with suggestions from recent financial research that the ex-post equity risk premium (i.e. the return investors have historically earned on risky stocks in excess of risk free bonds [where the term "risk free" in this context implies zero credit risk]) substantially over-estimates the equity risk premium investors require ex-ante (i.e. the future return they think they will receive at the time they invest), because of survivorship biases and other factors in the standard data and estimation procedures? Please explain your answer.

Response:

No. In general, Dr. Vander Weide disagrees with the methods used to reach the conclusion that ex post equity risk premiums "substantially" over-estimate "the equity risk premium investors require ex-ante."

73.2 In light of this over-estimation, what downward adjustments might be appropriate to the market equity premium estimates?

Response:

Dr. Vander Weide disagrees with the hypothesis of the question. In particular, he disagrees that "downward adjustments" are appropriate.

74.0 Reference: Exhibit B-1, Tab 4 Written Evidence of Dr. Vander Weide p. 16
Business Risk

Dr. Vander Weide stated that the business risk of electric and natural gas utilities is similar in the U.S. and Canada. Three factors were cited, namely: technology to deliver, the economics of transmission and distribution, and the regulatory structures and principles.

74.1 Does Dr. Vander Weide have any evidence regarding the similarity of technologies of natural gas facilities? If possible, please provide a comparison of the O&M expense per customer and Net Gas Plant in Service per customer between TGI and U.S. natural gas utilities that have allowed ROEs of 10.3 to 10.5 percent.

Response:

Dr. Vander Weide's statement at page 16 was meant to be a general statement that is consistent with his many years of experience in studying natural gas utilities. He has not conducted a specific study of the O&M expense per customer and Net Plant in Service per customer for TGI and the U.S. natural gas utilities. Such a study would be both time consuming and costly, and it is unlikely that such a study would produce relevant information for the purpose of determining TGI's fair rate of return on equity. However, given the collaboration of Canadian and U. S. gas utilities and their adoption of common practices, Dr. Vander Weide believes that, on average, Canadian and U. S. utilities use similar technologies; and thus that the business risk factors noted above will converge over time.

74.2 Does Dr. Vander Weide have any evidence regarding the lifeline rates for residential customers of natural gas utilities in the U.S. vis-à-vis TGI? Does Dr. Vander Weide have any evidence on the benchmark SQIs of natural gas utilities in the U.S. vis-à-vis TGI?

Response:

(a) Dr. Vander Weide has not conducted a study of the lifeline rates for residential customers of natural gas utilities in the U.S. compared to rates of TGI (Dr. Vander Weide understands that TGI does not have lifeline rates). Such a study would be impractical because each natural gas utility's lifeline rates would need to be studied separately in each regulated jurisdiction. Dr. Vander Weide's group of natural gas utilities were selected to be representative of the overall risk of investing in TGI. Since lifeline rates would have a relatively small impact on each utility's overall risk, such a study would not provide relevant information for determining TGI's fair rate of return in this proceeding.

In addition, to the extent lifeline rates reduce the risk of uncollected receivables, this risk is relatively small, because uncollected receivables are generally treated as an expense for the purpose of ratemaking.

(b) No, Dr. Vander Weide does not have evidence comparing TGI's SQIs to natural gas utilities in the US. As he understands from discussions with the Company, the benchmark Terasen SQIs were introduced as part of a performance-based rate settlement in 2004 in order to ensure that service quality was not sacrificed in the pursuit of operating efficiencies and cost savings. As such, they are an internal comparison of measures specific to TGI's past performance.

There would be no basis on which to make comparisons with other utilities on inwardly-focused measures.

74.3 Please provide general comments on the prevalence of deferral accounts for throughput variances, gas costs, interest expense variances, flow through adjustments of exogenous factors; and risk of disallowance in the U.S. natural gas utilities. Please compare the U.S. experience with the terms under the TGI's current Performance Based Review Plan.

Response:

Most U. S. gas utilities have automatic rate adjustment mechanisms for purchased gas costs and weather normalization. Many U. S. gas utilities have decoupling mechanisms that seek to stabilize revenues by "decoupling" gas rates from gas volumes. Decoupling occurs either through a rate design that allows recovery of fixed costs from fixed monthly charges, or through a revenue normalization adjustment mechanism that increases rates or refunds rates to customers for the difference between actual revenues and authorized revenues. Please see chart in Attachment 74.3.

As noted on pages 19 – 20 of Terasen's 2008 Annual Report, there are three regulatory mechanisms in place for Terasen to reduce the impact of unanticipated changes in forecast costs and revenues. The first two relate to the recovery of gas costs (Gas Cost Reconciliation Account and Midstream Cost Reconciliation Account), and the third seeks to stabilize revenues from residential and commercial customers (Revenue Stabilization Adjustment Mechanism). In addition, Terasen has an interest rate deferral account to absorb interest rate fluctuations.

75.0 Reference: Exhibit B-1, Tab 4 Written Evidence of Dr. Vander Weide p. 16
Allowed ROEs

75.1 Dr. Vander Weide states that the average allowed rates of return on equity for U.S. utilities is 10.4 percent. Please show how this average figure is derived. Are the ROEs from recent rate cases subsequent to 2008? Please provide the dates as to when the ROEs were set.

Response:

The average allowed rates of return on equity for U. S. electric and gas utilities during the past two years, 2006 through 2008, are shown on Schedule 3, pages 44 – 46, of Dr. Vander Weide's written evidence. The tables display the date a company's ROE was established (that is, the date of the commission order), the name of the utility whose ROE is being set, the state where the ROE is being set, and the ROE established. The 10.4 percent average return is simply the average of all the returns shown in the schedule. Dr. Vander Weide shows the most recent two years of data that were available at the time he prepared his written evidence.

75.2 At lines 26 to 30, Dr. Vander Weide states that deferral accounts generally reduce the gap between a utility's actual and allowed returns, they do not necessarily reduce the gap between a utility's actual and required returns. Please validate the above statement. Please provide, for each US utility that has been used to compare to TGI, its risk deferral mechanisms and compare these mechanisms to those afforded TGI by the BCUC.

Response:

(a) The statement is validated by Dr. Vander Weide's written evidence, including his six tests of whether the current AAM ROE Formula produces a fair return for TGI.

(b) With regard to U.S. gas utilities, please see response to BCUC IR 1.74.3. With regard to U.S. electric utilities, Dr. Vander Weide is aware from his experience in regulatory proceedings that most U. S. electric utilities have automatic fuel cost adjustment mechanisms and pass-through accounts for uncontrollable items such as demand management programs, costs of environmental protection, franchise fees, revenue taxes, and storm-related surcharges. In addition, most U. S. electric utilities have annual resource planning reviews with the utility commission in which the commission approves the utility's long-term capital expenditure plans. Once plans are approved, the utility's capital expenditures are assumed to be prudent unless proven to be otherwise.

75.3 At the bottom of page 16 it is stated that Canadian utilities face greater regulatory risk than US utilities because of the ROE formulas. Please reconcile this statement with the greater regulatory certainty that utility analysts have reported in the past.

<u>Response:</u>

Utility analysts use the phrase "regulatory certainty" to indicate that Canadian utilities have a reasonable likelihood, in the short run, to earn their *allowed* rates of return. Regulatory risk generally refers to the likelihood that Canadian utilities will earn less than their *required* rate of return. Dr. Vander Weide's written evidence demonstrates that Canadian formula allowed returns are significantly less than Canadian utilities' required return. Thus, Canadian utilities face greater regulatory risk than U. S. utilities because of the Canadian ROE formulas, even though Canadian utilities have a reasonable likelihood of earning their allowed returns in the short run.

76.0 Reference: Exhibit B-1, Tab 4 Evidence of Dr. Vander Weide p. 19

76.1 Please explain the reason for choosing 20-year U.S. Treasury bonds as opposed to 30 year bonds.

Response:

Dr. Vander Weide chose 20-year U.S. Treasury bonds because data on the yield on U.S. Treasury bonds is available from Ibbotson Associates for the last 80 years, whereas Dr. Vander Weide is not aware of a data source for yields on 30-year Treasury bonds that go back continuously over such a long period of time. In addition, because both 20-year and 30-year U.S. Treasury bonds are long-term obligations of the federal government, there is generally little difference in the yields on these bonds. Dr. Vander also notes that his ex ante risk premium studies, described beginning at page 17, extend back over approximately the last ten years; the 30-year U.S. Treasury bond was not offered over the years 2002 to 2006.

77.0 Reference: Exhibit B-1, Tab 4 Evidence of Dr. Vander Weide p. 23 Tables 2 and 3

Tables 2 and 3 indicate that Canadian utilities have higher standard deviations and much higher returns than the S&P/TSX Canadian market.

77.1 Does this make sense given the low betas calculated by other witnesses and the expectation that returns should be less than the market?

Response:

Dr. Vander Weide agrees that the evidence in Table 2 and Table 3 is inconsistent with the low betas for Canadian utilities that are sometimes calculated by other witnesses. However, as noted in response to interrogatory BCUC IR 1.14.5, Dr. Vander Weide believes that the problem lies not with the data presented in Table 2 and Table 3, but, rather, with the low estimated betas for Canadian utilities. The traditionally-calculated betas of other witnesses depend on the correlation, or co-variation, between the short-run returns on the utility stocks and the short-run returns on the market index. Because utility investors invest for the long run, they do not consider the correlation, or lack thereof, between short-run utility returns and short-run returns on the market index as a measure of risk. Utility investors are more concerned about the correlation between the long-run returns on utility stocks and long-run returns on the market index. However, the correlation between the long-run returns is difficult to measure because of the lack of a reasonable sample of long-run returns. Also see full response to BCUC IR 1.14.5.

77.2 Does it indicate that the BMO Capital Markets Utilities Stock is not representative? Would it indicate that returns awarded by regulators have been too high for the betas of Canadian utility stocks?

Response:

(a) No. The BMO Capital Markets utilities stock data set only includes Canadian companies that receive a significant portion of their revenues from traditional utility operations.

(b) No. As discussed in Dr. Vander Weide's written evidence, the data in Table 2 and Table 3 indicate that the risk of Canadian utility stocks compared to the risk of the Canadian stock market as a whole is greater than is implied by the AAM ROE formula. This evidence also indicates that the AAM ROE formula produces returns that are lower than the returns required by investors in Canadian utility stocks.

77.3 Please explain what work the author did to verify the reasonableness of his statistical regressions to expected results and the findings of other analysts. Please confirm that total returns were used including dividend reinvestment.

<u>Response:</u>

Statistical regressions are not required to estimate the standard deviations shown in Table 2 and Table 3. Dr. Vander Weide confirms that total returns were used, including both dividends and capital gains.

78.0 Reference: Exhibit B-1, Tab 4, Written Opinion of Dr. Vander Weide, p. 31 Econometrics

In lines 4-6, and in Exhibit 13, a regression model is proposed relating the risk premium (variable RPcomp) to the interest rate (I_B).

78.1 Are any econometric problems (especially biases in results) created by the fact that the variable I_B effectively appears on the left hand side of the regression as well as the right side, given that RPcomp is defined as the equity return, DCFcomp, minus I_B?

Response:

No. Because there is sufficient independent variation in the DCF results, there are no econometric problems created by the appearance of the variable I_B on the left side and right side of the regression equation.

78.2 Please provide results from unit root test on the variable I_B.

Response:

The unit root test is used to discover whether a variable such as I_B is serially correlated. As explained in Exhibit 13, Appendix 4, in conducting his regressions, Dr. Vander Weide examined the residuals from his initial regression analysis to determine whether the residuals were serially correlated (non-zero serial correlation indicates that the residual in one time period tends to be correlated with the residuals in previous time periods). Dr. Vander Weide found from his initial examination that the residuals from his first regression analysis were serially correlated. He therefore made adjustments to his data to adjust for serial correlation in the residuals. The common procedure for dealing with serial correlation in the residuals is to estimate the regression coefficients in two steps. First, a multiple regression analysis is used to estimate the serial correlation coefficient, *r*. Second, the estimated serial correlation coefficient is used to transform the original variables into new variables whose serial correlation is approximately zero. The regression coefficients are then re-estimated using the transformed variables as inputs in the regression equation. Because Dr. Vander Weide's regression analysis includes only the transformed variables as inputs in the regression equation, the regression results are not distorted by serial correlation in the variables or residuals.

In addition, in preparing this response, Dr. Vander Weide determined that there are typographical errors in Exhibit 13, Appendix 3, which should be replaced with the revised Appendix 3 provided in Attachment 78.2 to correct typographical errors in the reported statistics; the data as filed relate to a study from an earlier time period. Please note that there is no change to Dr. Vander Weide's study results or conclusions as reported in the body of his written evidence.

78.2.1 Is I_B a stationary variable? If not, why not use the first difference of I_B in the regression to avoid potentially spurious results?

Response:

The initial values for I_B are non-stationary. However, as discussed in response to BCUC IR 1.78.2, Dr. Vander Weide transformed the variables on both the left and right sides of the equation in order to remove the serial correlation. The transformation is described by the following equation:

$$y_t' = y_t - r y_{t-1}$$

$$x_t' = x_t - r x_{t-1}$$

where y_t' and x_t' are the transformed variables, and r is an estimate of the serial correlation coefficient.

For a complete explanation of this procedure, see chapters on treating serial correlation in standard texts on econometric methods.

78.3 Are DCFcomp and I_B cointegrated? If yes, is the model in any way misspecified, or at least suboptimally specified, as written and estimated? If no, please explain.

Response:

No. The transformed values of DCF_{comp} and I_B are not cointegrated because, as explained in response to BCUC IR 1.78.2 and BCUC IR 1.78.3, they are not serially correlated. As noted, Dr. Vander Weide used only transformed values that are not serially correlated in his regression analysis.

78.4 If any of the foregoing are in fact econometric problems, then what happens to the regression results and conclusions if these issues are addressed? Please report the results. Does that change any of the conclusions regarding the appropriate ROE for TGI?

Response:

Since none of the foregoing are econometric problems, no change in Dr. Vander Weide's conclusions is required.

78.5 Please confirm that the average stock return presented in Table 4 includes dividends and reinvestments.

Response:

Confirm.

79.0 Reference: Exhibit B-1, Tab 4, Written Opinion of Dr. Vander Weide, p. 33 DCF Robustness

Concerning robustness and confidence in the DCF results,

79.1 How robust are the estimates of "k", the cost of equity, with respect to a variety of reasonable changes in data and time periods?

Response:

In his written evidence, Dr. Vander Weide presents the best data available at the time of his analysis to estimate prices, growth rates, and dividends in his DCF analysis. In his opinion, there is no reason to change the values used in his analysis.

79.1.1 For example, vary the estimate of "g" and "D" by changing data windows or assumptions used to estimate "D" and "g" and report results – how sensitive is the cost of equity to the assumptions used regarding these inputs into the DCF model?

Response:

Dr. Vander Weide used the most recent four quarterly dividends to estimate the "d" component in his DCF analysis, and the most recent I/B/E/S estimate of EPS growth to estimate the "g" component in his DCF analysis. Dr. Vander Weide does not believe it would be appropriate to use historical dividends from prior years or growth estimates from prior years in his DCF analysis because such estimates would be inconsistent with his use of recent prices. Further, the cost of equity is forward looking, and it is appropriate to use the most recent data at the time of the analysis.

79.2 The DCF model requires a price "P" to be specified. Is it true that, all else being equal, the lower the price "P" the higher the cost of equity (called "k") by construction? If no, please explain.

Response:

Although it is strictly true, all else being equal, that the lower the price, the higher the cost of equity, all else is rarely equal. Specifically, the price generally rises or falls because of changes in expected dividends or growth rates.

79.3 Is it not the case that the stock market was significantly below its trend at the time Dr. Vander Weide's Evidence was written and thus that the value of "P" employed might have been lower than the value of "P" would be using other potential time periods?

Response:

As discussed above, Dr. Vander Weide uses the most recent prices available at the time of his analysis along with contemporaneous dividends and growth rates in his DCF analysis. It would make no economic sense whatsoever to adjust the price term in the DCF model to reflect a belief that a price is "significantly below its trend" without also adjusting the dividends and growth rates in the DCF model; however, it makes no sense for an analyst to speculate on a "trend" in prices, dividends, and growth rates, when actual market information is available that already reflects all the information available to investors, including any "trends." Thus, Dr. Vander Weide uses the most recent data at the time of his analysis.

79.3.1 For example, please use the average "P" over the past year, and use the value of "P" as of July 2009, and note the sensitivity of the results regarding the estimate of "k". How robust is the estimate of "k"? Please report on the sensitivities of the results.

Response:

See response to BCUC IR 1.79.3.

79.4 Please provide standard deviations along with point estimates when reporting results from the foregoing estimations. For example, on pp. 60 and 61, at the bottom of each table, please report the standard deviations of the estimates in addition to the mean.

Response:

Please see response to BCUC IR 1.79.3. The standard deviation of the DCF results in Exhibit 8, page 60, is 1.75 percent, and for the DCF results in Exhibit 9, page 61, 1.71 percent.

80.0 Reference: Exhibit B-1, Tab 4, Written Opinion of Dr. Vander Weide, pp. 33, 34 DCF

In applying the DCF Model, the comparable utilities analysis is done after culling the companies to eliminate those that have deteriorating conditions.

80.1 Does this not result in a residual group of companies that are the best possible performers? Do these conditions precedent to running a DCF model not indicate major limitations in the usefulness of the DCF model?

Response:

No. Dr. Vander Weide's written evidence at page 33 lists the five criteria he uses to select comparable companies: all the utilities in Value Line's electric and natural gas industry groups that: (1) paid dividends during every quarter and did not decrease dividends during any quarter of the past two years; (2) have at least three analysts included in the I/B/E/S mean growth forecast; (3) are not in the process of being acquired; (4) have a Value Line Safety Rank of 1, 2, or 3; and (5) have investment grade S&P bond ratings. Dr. Vander Weide did not "cull" the companies "to eliminate those that have deteriorating conditions." Rather, he eliminated companies that were either not comparable in risk to TGI or whose data are not reliable inputs for a DCF analysis. A further discussion of why Dr. Vander Weide uses his selection criteria is contained in Dr. Vander Weide's written evidence, response to Questions 101 – 103, page 33 – 34.

(a) No. The residual group of companies is the set of companies that are most comparable to TGI.

(b) No. Dr. Vander Weide's selection criteria do not indicate any "major limitations" in the usefulness of the DCF model. Rather, as discussed above, these selection criteria are designed to select companies that are comparable in risk to TGI. Thus, to be consistent with the fair return standard, Dr. Vander Weide applies the DCF model only to a comparable group of utilities, because the fair return standard requires that the allowed return for TGI be equal to the returns investors expect to earn on other investments of comparable risk.

81.0 Reference: Exhibit B-1, Tab 4, Written Opinion of Dr. Vander Weide, pp. 35, 36
Comparable Risk Utilities

Dr. Vander Weide opines that the business risk of TGI is approximately equal to the average business risk of U.S. electric and natural gas utilities.

81.1 Please provide the analyses carried out to confirm this statement

Response:

Dr. Vander Weide's opinion is based on his knowledge, from more than 30 years of experience in utility regulation, that both TGI and U. S. electric and gas utilities: (1) sell energy services under regulated rates; (2) face similar competitive forces; (3) are regulated under similar cost of service mechanisms; and (4) must make large investments in long-lived energy facilities whose costs are largely sunk once they are made. Please also see response to BCUC IR 1.74.3 and BCUC IR 1.75.2.

81.2 If the awarded ROE and equity thickness for TGI is dramatically lower than U.S. utilities that are competing for capital in a global market, would one have expected TGI to face greater difficulty in raising debt? Would one have expected TGI's total returns to significantly lag the S&P/TSX Composite? Has this happened?

Response:

Dr. Vander Weide has not studied TGI's difficulty in raising debt because his testimony is concerned with TGI's fair rate of return on equity. Dr. Vander Weide has also not studied TGI's total returns in the marketplace because TGI has not been publicly-traded in recent years.

82.0 Reference: Exhibit B-1, Tab 4, Written Opinion of Dr. Vander Weide, pp. 31, 35 Estimates

Concerning estimates in Tables 4 and 5 of Dr. Vander Weide’s Evidence:

82.1 Please specify the time periods employed in the estimations.

Response:

With regard to the data shown in Table 4, the time periods employed are the periods from 1956 – 2008 and 1983 – 2008, as shown in the table heading columns. With respect to the summary of Dr. Vander Weide’s cost of equity study results shown in Table 5, as described in his written evidence concerning each cost of equity study: ex post studies employ the annual experienced risk premium data from 1956 – 2008 and 1983 – 2008 and the recent forecast long-term Canada bond yield (see Table 4 and Questions and Answers 92 - 93, pages 30 - 31 of Dr. Vander Weide’s written evidence); ex ante studies employ monthly data beginning June 1998 through February 1999 (see Questions and Answers 96 – 98, pages 32 – 33 and Exhibit 5, Exhibit 6, and Exhibit 13, Appendix 3 of Dr. Vander Weide’s written evidence); discounted cash flow studies employ data beginning December 2008 through February 2009 (see Question and Answer 104, page 34, and Exhibit 8 and Exhibit 9).

82.2 Please provide standard deviations along with point estimates.

Response:

The standard deviation of returns for the BMO/CM utilities stock data set and the S&P/TSX Utilities are reported in Table 1, page 23, of Dr. Vander Weide’s written evidence and are reproduced below. With regard to the DCF results shown in Exhibit 8 and Exhibit 9, the standard deviation of the estimates is provided in response to BCUC IR 1.79.4 above.

TABLE 1
STANDARD DEVIATION OF ANNUAL RETURNS
BMO CM UTILITIES STOCK DATA SET,
S&P/TSX UTILITIES, AND TSX MARKET INDEX

Period	BMO CM Utilities Stock Data Set	S&P/TSX Utilities Index	TSX Canadian Market
1983 – 2008	17.29	18.64	16.67
1956 – 2008		15.76	16.72

82.3 Please report results obtained using geometric averages, along with arithmetic averages.

Response:

For the reasons stated in response to BCUC IR 1.72.1, Dr. Vander Weide does not believe that geometric averages should be used to estimate the forward-looking required return. Nonetheless, the geometric average returns are shown below.

TABLE 2 REVISED IN RESPONSE TO BCUC IR 1.82.3
GEOMETRIC AVERAGE RISK PREMIUM RESULTS

Comparable Group	Period of Study	GEOMETRIC Average Stock Return	GEOMETRIC Average Bond Yield	GEOMETRIC AVERAGE Risk Premium
S&P/TSX Utilities	1956 – 2008	10.73	7.51	3.23
BMO CM Utilities Stock Data Set	1983 – 2008	13.06	7.63	5.43

With regard to the data reported in Table 5, the summary of results of each of Dr. Vander Weide's cost of equity studies, it is not possible to provide a geometric average. These data represent the most recent results, not the results of a long time series of data. Since a geometric average is appropriate for only a long series of historical data, to attempt to calculate a geometric average of the cost of equity results displayed in Table 5 would not make sense.

83.0 Reference: Exhibit B-1, Tab 4, Written Opinion of Dr. Vander Weide, p.39 Exhibit 1

83.1 Please add a column to the table in Exhibit 1 to show the TSX composite total return and the risk premium.

Response:

Please refer to Attachment 83.1.

OTHER FILINGS AND DOCUMENTS

Please file these documents/reports requested in this section electronically in PDF searchable format on CD. Please note that hard copies are not required.

84.0 Reference: Annual Reports and Other Filings

84.1 Please file the Fortis Inc. Short Form Prospectus dated March 7, 2007.

Response:

Please refer to Attachment 84.1.

84.1.1 Please provide details of the Fortis Inc. acquisition of Terasen Inc. What is the difference between a bought deal and a best efforts basis? How was investor interest in the Fortis Inc. subscription receipts?

Response:

As per Fortis news release dated February 26, 2007:

On February 26, 2007, Fortis Inc. entered into an agreement to acquire Terasen from a wholly owned subsidiary of Kinder Morgan, Inc. (NYSE:KMI), a U.S. energy transportation, storage and distribution company based in Houston, Texas, for a purchase price of $3.7 billion, including the assumption of approximately $2.3 billion of debt. Terasen (formerly BC Gas) is a holding company headquartered in Vancouver, British Columbia operating two principal lines of business: natural gas distribution and petroleum transportation. The acquisition does not include the petroleum transportation assets of Kinder Morgan Canada (formerly Terasen Pipelines), which are comprised primarily of refined and crude oil pipelines.

The natural gas distribution business of Terasen, referred to as Terasen Gas, is the third largest gas distribution utility in Canada. Terasen Gas serves approximately 900,000 customers or 95% of natural gas customers in British Columbia. The Company owns and operates 44,100 kilometres of gas distribution pipelines and 4,300 kilometres of gas transmission pipelines. Its service territory includes the populous lower mainland, Vancouver Island, and the southern interior of the province. As of December 31, 2006, Terasen Gas had an aggregate of approximately $3.8 billion of assets, an aggregate rate base approaching $3.0 billion and approximately 1,200 employees.

What is the difference between a bought deal and a best efforts basis?

Bought Deal:

The entire issue of new securities is bought from the issuing company by the underwriters and resold to its clients. The underwriter risks its own money in a bought deal, and in the event that the price has to be lowered to sell out the issue, the underwriter absorbs the loss.

Best Efforts:

The underwriter agrees to use his or her best efforts to sell a new issue of securities, but does not guarantee to the issuing company that any or all of the issue will be sold. The underwriter acts as an agent for the issuer in distributing the issue to his clients.

How was investor interest in the Fortis Inc. subscription receipts?

Fortis entered into an agreement, on February 26, 2007, with the Underwriters under which they agreed to purchase from Fortis and sell to the public 38,500,000 Subscription Receipts at $26.00 each for gross proceeds to the Corporation of $1,001,000,000. On March 15, 2007 the Underwriters exercised their over-allotment option and purchased an additional 5,775,000 Subscription Receipts at a purchase price of $26.00 each for gross proceeds from the over-allotment option to the Corporation of $150,150,000.

Fortis was informed by the underwriters for the subscription receipt deal that investor interest in the bought deal was strong with the initial issue amount being fully sold out over a couple of days.

84.2 Please provide a copy of the 2008 Fortis Inc. Annual Report.

Response:

Please refer to Attachment 84.2.

84.3 Please provide a copy of the 2008 Terasen Inc. Annual Report "Delivering BC's energy future".

Response:

Please refer to the response to BCUC IR 1.39.1, Attachment 39.1.

84.4 Please provide a copy of the financial statements of Terasen Gas Inc. for each year from 2004 to 2008.

Response:

Provided under Attachment 84.4 are the 2004 to 2008 annual audited financial statements for Terasen Gas Inc.

84.5 Please provide a copy of the Terasen Gas Customer Advisory Council Meeting May 27, 2009 materials.

Response:

Please refer to Attachment 84.5.

84.6 Please file the TGI April 24, 2008 Short Form Base Shelf Prospectus. Also file the TGI Pricing Supplement No. 2 dated February 19, 2009 and the Terasen Gas Inc. Earnings Coverage Ratio as at March 31, 2009 and December 31, 2008 which are all in conjunction with the base shelf prospectus dated April 24, 2008.

Response:

Please refer to Attachment 84.6.

84.7 Please file the TGI 2008 Management's Discussion and Analysis dated February 6, 2009.

Response:

Please refer to Attachment 84.7.

84.8 Please file the TGI Annual Information Form for the year ended December 31, 2008 dated February 18, 2009.

Response:

Please refer to Attachment 84.8.

85.0 Reference: Purchases of Terasen Gas Inc.

85.1 What was the premium above market price and the Price to Book ratio paid by Kinder Morgan for Terasen Inc.?

Response:

Kinder Morgan ("KMI") acquired Terasen on November 30, 2005 for a pro-rated value of $35.91 per Terasen share based on KMI's share price and C$/US$ exchange rates as of July 29, representing a premium of approximately 20% over the 20 day average closing price and a premium of 14% to the prior day's close at the time the acquisition was announced on August 1, 2005. At the time of the acquisition, the reported BV/share was $13.57. The total Price to Book Value per share of the transaction was 2.6 times.

85.2 What were the book value, transaction price, and resulting Price to Book ratio paid by Fortis Inc. for Terasen Inc.? Explain the difference between Terasen Inc. as acquired by Kinder Morgan and sold by Kinder Morgan (i.e. pipeline operations).

Response:

Fortis Inc. acquired Terasen Inc., which consisted primarily of the gas utilities TGI, TGVI and TGW, while Kinder Morgan retained the pipeline business, which was comprised mainly of Trans Mountain Pipeline, Express Pipeline and Corridor Pipeline. Prior to the transaction, Kinder Morgan had disposed of the Terasen's water utility and utility services businesses.

The total book values of assets acquired by Fortis Inc. were approximately $3.25 billion. The price paid for the assets was $4.15 billion, reflecting a goodwill premium of $900 million and a Price to Book Value per share of 1.28 times.

86.0 Reference: Credit Rating Agency Reports

86.1 Please provide all presentations and documentation made to bond rating agencies since 2004 in regards to TGI.

Response:

Copies of presentations prepared for rating agencies are attached. Presentations made to credit rating agencies contain confidential financial information that has not been made public. The confidential information has been removed from the presentations. No credit rating agency presentation was prepared in 2007. See the Attachment 86.1.

86.2 Please provide all credit rating agency reports (i.e. DBRS, S&P and Moody's) since 2004 in regards to TGI.

Response:

Please refer to Attachment 86.2.

86.3 Please file the latest Terasen Inc. credit rating report from each agency.

Response:

Please refer to Attachment 86.3.

86.4 Please file the latest Fortis Inc. credit rating report from each agency. If the report is an update file the previous substantive report.

Response:

Please refer to Attachment 86.4.

86.5 Tab 3 – Expert Testimony of Kathleen C. McShane in Financial – Schedule 3 shows the Moody’s Bond Rating for Terasen Gas (Vancouver Island) Senior Unsecured as A3 which is the same rating as Terasen Gas for Senior Unsecured debt.

86.5.1 Please file the latest TGVI Moody’s credit rating agency report.

Response:

Please see attachment 86.5.1.

Note that DBRS also provides a private rating on TGVI which is currently BBB (high).

86.5.2 The Application on page 9 requests that TGVI’s specific risk premium of 70 basis points that was established for TGVI in the 2006 Decision continue, and be applied to the new Benchmark ROE that is to be made effective July 1, 2009. If the proposed new Benchmark ROE was approved as filed, directionally how would the higher ROE affect the TGVI credit rating and the ability to attract capital? Please explain.

Response:

Directionally, the higher benchmark ROE would improve the TGVI credit rating metrics which may lead to an increase in ratings. However, the ROE level is one factor affecting the overall credit rating, therefore, it is not possible to determine with certainty the affect on the ratings from an increase in the benchmark ROE. An increase in the ROE to a satisfactory level to address the Fair Return Standard would make the likelihood of a rating downgrade less likely. To the extent that credit metrics are improved, all else equal, an investor in comparing investment opportunities may view the improved credit metrics of TGVI as beneficial, which would improve TGVI’s ability to compete for capital. In addition, when a shareholder is considering competing discretionary investment opportunities, preference would be given first to the investment with the higher return, therefore, an improved ROE will increase the likelihood of attracting capital.

86.6 Tab 3 – Expert Testimony of Kathleen C. McShane in Financial – Schedule 15 provides a reference to the Standard and Poor's, Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies: Strongest to Weakest (March 10, 2009).

86.6.1 Please provide the Standard & Poor's "Issuer Ranking: Canadian Gas and Electric Utility Companies, Strongest to Weakest". Please file similar reports from the other credit ratings agencies, if available.

Response:

The requested report is provided in Attachment 86.6.1. Ms. McShane is not aware of any similar reports from the other credit rating agencies.

86.7 Since 2004 please provide details of any credit rating agency ratings change or change to ratings outlook for TGI, Enbridge Gas Distribution, and Union Gas Limited.

Response:

In the table below are details of credit rating agency changes and ratings outlook changes since 2004 for TGI, Enbridge Gas Distribution and Union Gas Limited. (Ratings Source: RBC Capital Markets for Enbridge Gas Distribution and Union Gas Limited).

	Agent	Rating	Outlook	Rating Period
Enbridge Gas	S&P	A-	stable	2003-Present
	DBRS	A		2003-Present
	Moody's	Not rated	n/a	n/a
Union Gas Limited	S&P	BBB+	negative	Past - Jan 2004
	S&P	BBB	stable	Feb - Nov 2004
	S&P	BBB	positive	Dec 2004 - Jan 2005
	S&P	BBB	stable	Feb - Apr 2005
	S&P	BBB	negative	May - Aug 2005
	S&P	BBB	stable	Sep 2005 - Apr 2006
	S&P	BBB	positive	May 2006
	S&P	BBB	developing	Jun -Aug 2006
	S&P	BBB	positive	Sep - Dec 2006
	S&P	BBB+	stable	Jan 2007 - Present
	DBRS	A	stable	2000 - Present
	Moody's	Not rated	n/a	n/a
TGI	S&P	BBB	Negative	2003 - Jan 2007
	S&P	BBB	Postive	Jan - May 2007
	S&P	A	Stable	Jun 2007 - Present
	Moody's	A2	Stable	2004 - July 2005
	Moody's	A2	Negative	Aug - Nov 2005
	Moody's	A3	Stable	Dec 2005 - Present
	DBRS	A	Stable	2004 - Present

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87.0 Reference: Analyst Reports

87.1 Please provide all presentations and documentation made to financial analysts since 2005 in regard to TGI and TGVI.

Response:

The only presentations made to financial analysts are those made to credit rating agencies, as provided in the response to BCUC IR 1.86.1. As TGI and TGVI do not have publicly traded common shares, neither company is followed by equity analysts, therefore, there has been no presentations made to equity analysts in regard to either TGI or TGVI.

87.2 Please provide all financial analyst reports since 2005 in regard to Terasen Inc. and TGI.

Response:

With regards to Terasen Inc., we have included the equity analyst reports from 2005 that were filed as part of the 2005 ROE and Capital Structure Application. Terasen Inc. was acquired by Kinder Morgan Inc. in November 2005. Since then there have been no equity analyst reports issued on Terasen Inc. As TGI does not have common shares that are publicly traded, there are no equity analysts' reports that we are aware of.

With respect to Terasen Inc. and Terasen Gas Inc. included in Attachment 87.2 are the corporate debt research reports since 2005 published by Bank of Montreal and Bank of Nova Scotia research analysts.

87.3 Please file all financial analyst reports on Fortis Inc. since 2006.

Response:

Please refer to Attachment 87.3.

88.0 Reference: Deferral Accounts and Risk Management Plan

88.1 Please list all approved TGI deferral accounts with a short description and approval order. Also note if other Canadian utilities would typically have similar accounts. If available, identify which utilities have the same deferral account.

Response:

For a list of all approved TGI deferral accounts with balances as of December 31, 2008, see Attachment 88.1.

A review of the published financial statement notes of other Canadian utilities (Enbridge Gas, Union Gas, ATCO Ltd., Gaz Metro, Pacific Northern Gas (PNG), Fortis subsidiaries) shows that other Canadian utilities would typically have similar accounts, where similar circumstances exist. In particular:

- Commodity/Purchase Cost Deferral Accounts (similar to MCRA and CCRA) for Enbridge, Union Gas, Atco, Gaz Metro, PNG, Newfoundland Power, Maritime Electric
- Revenue or Weather Stabilization Accounts (similar to RSAM) for Enbridge, Atco, Gaz Metro, PNG, Newfoundland Power
- Demand Side Management or Energy Efficiency for Enbridge, Gaz Metro, Fortis BC
- Deferred costs of applications for Enbridge, Atco, PNG
- Earnings Sharing for Enbridge, Gaz Metro, Fortis BC
- Mitigation Revenues (similar to SCP Mitigation) for Union Gas and Atco

Many utilities also appear to have a deferral account for changes in tax rates. There may be additional deferral accounts for these companies for uncontrollable items that are not deemed to be material enough for financial statement disclosure. In addition, each utility has deferral accounts related to their own specific projects and circumstances.

88.1.1 Please describe the TGI Price Risk Management Plan? Explain the resulting benefits of implementing the plan.

Response:

Terasen Gas strives to provide safe, reliable and cost-effective service to energy customers within its service areas. The Price Risk Management Plan (the "PRMP") is one of the tools that Terasen Gas uses to support this goal. The primary objectives of the Price Risk Management Plan are to improve the likelihood that natural gas remains competitive with electricity over the term of the Plan, moderate the volatility of market gas prices and their effect on rates for customers, and reduce the risk of regional price disconnects (i.e. wherein Sumas pricing separates significantly from Station #2 or AECO hub pricing in periods of high demand). Terasen Gas believes these objectives have served customers well, providing value through rates significantly less volatile than prices in the natural gas marketplace at a reasonable cost that is competitive, at least on a variable cost basis, with electricity rates.

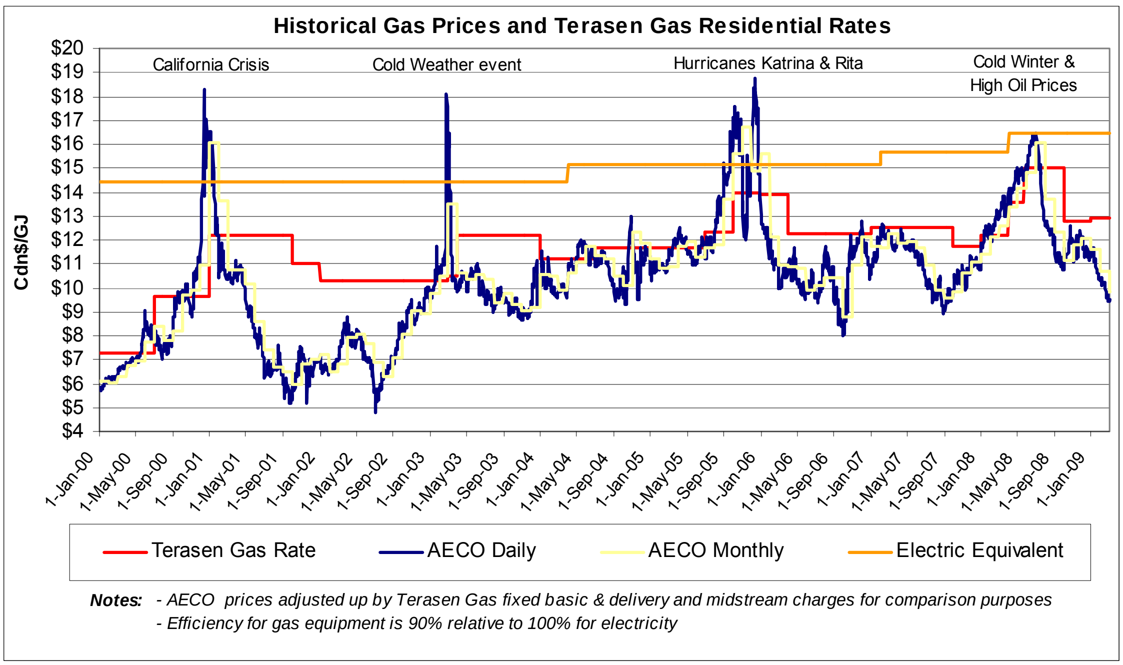
It is important to note that customer perceptions of the competitiveness of Terasen Gas rates relative to electricity rates are critical in maintaining competitive rates. To the degree that the hedging program can dampen the effects of market price volatility on rates Terasen Gas will improve the probability of successfully maintaining customer growth and reducing customer migration to electricity as a heating source. Customers' reaction and concern to the volatile natural gas prices can be demonstrated by BCOAPO's recent statement in its final argument in the BC Hydro 2008 LTAP proceeding, which states:

> *"BCOAPO recognizes that Terasen's current rate compares favourably against BC Hydro's trailing residential rate. Right now, customers choosing natural gas for space and water heating are seeing a definite financial benefit as compared to their electricity-using counterparts. However, given the volatile natural gas prices, this could change at any time and customers would again find themselves in a situation where natural gas is no longer even the most economic choice*."

BCOAPO and other customers' perceptions of future natural gas prices may have been altered recently with the oil pricing scenario that unfolded in 2008. On July 3, 2008 the NYMEX oil futures contract for August 2008 deliveries hit an all time high of $145 US/barrel. This type of pricing event can shape customers perception of what the long term price for oil or natural gas may be and thus impact their investments and behaviour towards energy choice and highlights the necessity of an effective hedging program.

In February 2005, Terasen Gas engaged a research company to survey customers regarding their tolerance for volatility and the survey results confirmed that while customers will tolerate some volatility (annual bill increase of up to 17% in a year) it is certainly less than the volatility that has occurred in the recent past in the natural gas market. Terasen Gas' market-based rate offering provides customers with a choice amongst the longer-term fixed-rate offerings of marketers in the unbundled environment, while still protecting those customers that remain under this rate from the full impact of market price volatility and price spikes. The following graph illustrates the volatility reduction provided by the Terasen Gas rate (for residential customers) as well as the electric equivalent. The electric equivalent presented in the graph is the historical residential electric equivalent until October 2008 after which time a blended electric equivalent is shown (which is calculated by inflating 2008 rates by the approved increases to the revenue requirement in the Commission decision on the BC Hydro F2009/2010 Revenue Requirements Application).

Historical Gas Prices vs. TGI Natural Gas and Electric Rates



As an example, during 2008 Terasen Gas' residential rates increased by a total of 22%, above the tolerable rate increase of 17% indicated in the customer survey. Residential commodity rate increases occurring in 2008 became effective April 1, 2008 and July 1, 2008, with each commodity rate change representing an 11% increase in residential rates. Without the use of hedges the rate increases requested in 2008 would have totalled approximately 36% (based on the cost of gas twelve-month outlook without hedges in place). The AECO forward price curve, looking 12 months out, increased by about 50% during the same period. In October 2008, Terasen Gas' commodity rate reverted back close to the level prior to the price run-up during the middle of 2008, with a reduction in the residential rate by about 15%. So while the Terasen Gas rate does not follow market prices all the way down following price spikes, it also does not follow prices all the way up either, saving customers from rate shock and the 'rollercoaster' ride of market price volatility and improving the probability of remaining competitive with electricity rates.

Should prices for any of the hedging terms fall significantly to predefined price levels, Terasen Gas immediately hedges a preset amount with fixed price swaps in order to take advantage of a potentially short-term low-priced situation. This strategy is referred to as 'accelerated hedging'. The goal of this strategy is to increase the proportion of hedging executed at lower prices and decrease the proportion of hedging at higher prices, given that the maximum amounts of winter and summer hedging remain fixed. Consideration is also given to the fact that price dips may not be short-term in nature and so a balanced approach has been taken.

Terasen Gas hedges over a 36 months period, layer in hedges according to the predefined implementation schedule, and continue with a balanced mix of fixed price swaps and options. By extending the hedging period out to 36 months, Terasen Gas can reduce volatility and potentially capture prices below the forecasted electric equivalent, improving the ability to remain competitive with electricity over the longer term.

It is important to note that while the Price Risk Management Plan reduces the effects of market price volatility on customer rates, it does not remove all of the volatility and thus it still remains a market based rate. Terasen Gas feels this approach is important in order to present the appropriate price signals to customers in the interests of energy conservation and customer market awareness. Furthermore, as detailed in the Terasen Gas ROE and Capital Structure Application, while the Price Risk Management Plan may improve the probability of natural gas being competitive with electricity rates on a variable cost basis, significantly higher capital costs for natural gas heating compared to electric space heating present a challenge for Terasen Gas in attracting new customers to offset the declining use rates of existing customers.

88.1.2 Please describe the Company Use Gas Hedging for 2010-2011? Explain the resulting benefits of having this program.

<u>Response:</u>

Company use gas is primarily required to deliver natural gas to customers in a safe and efficient manner and includes line heater fuel, compressor fuel and liquid natural gas (LNG) plant fuel associated with moving natural gas to customers as well as gas used in Terasen Gas facilities and offices. The costs related to company use gas are covered through O&M expenditures and are subject to volumetric fluctuations based on weather, customer load requirements and pipeline operating conditions, and price fluctuations based on the variability in natural gas market prices. In order to reduce the fuel cost uncertainly related to commodity pricing and protect against future potential cost increases arising from natural gas price volatility in the future, Terasen Gas has executed hedge arrangements to fix the commodity price related to the forecast of company use gas for the period January 1, 2010 to December 31, 2011. Given that current market natural gas prices are depressed relative to recent historical averages, Terasen

Gas believes this to be a favourable time to hedge the pricing related to company use gas costs. Terasen Gas requested Commission approval to hedge company use gas in its letter dated May 29, 2009 and obtained Commission acceptance for hedging company use gas for 2010 and 2011 on June 11, 2009 per Letter No. L-44-09.

The forecast volumes related to company use gas are summarized in the table below and are the same for each of 2010 and 2011. The forecasts are based on historical actual usage.

Forecast Company Use Gas Volumes (GJ)

	Compressor	Line Heater	LNG	Facilities	Total	Per Day
January	26,150	16,912	1,100	5,000	49,162	1,586
February	19,100	35,452	700	4,600	59,852	2,138
March	9,000	27,246	100	5,000	41,346	1,334
April	2,000	20,015	750	2,500	25,265	842
May	500	13,666	750	2,500	17,416	562
June	200	5,951	50	1,500	7,701	257
July	200	5,577	50	1,000	6,827	220
August	200	3,275	50	1,000	4,525	146
September	500	1,736	50	1,000	3,286	110
October	3,000	4,735	750	1,000	9,485	306
November	12,100	8,432	100	2,500	23,132	771
December	32,400	12,005	1,100	4,500	50,005	1,613
Total	**105,350**	**155,000**	**5,550**	**32,100**	**298,000**	**816**

The hedge price of the Sumas fixed price swap Terasen Gas has subsequently implemented for the company use gas forecast volumes is \$6.44 US/MMBtu. This compares favourably to the historical five year average price of \$6.90 US/MMBtu and the historical five year high price of \$8.02 US/MMBtu. While the actual index prices for 2010 and 2011 could ultimately settle lower than the hedge price achieved, Terasen Gas believes that, given the volatility in the natural gas marketplace and potential for prices to move up in the future, this is a prudent approach in managing O&M costs on behalf of customers.

88.1.3 What are the commodity cost deferral accounts used by TGI? Explain the resulting benefits of having these deferral accounts.

Response:

Since April 2004, with the implementation of the Essential Services Model and the Commercial Commodity Unbundling Program the Gas Cost Reconciliation Account ("GCRA") was divided into a Commodity Cost Reconciliation Account ("CCRA") and a Midstream Cost Reconciliation Account ("MCRA"). These two new gas cost related deferral accounts are used to accumulate the difference between the costs incurred by Terasen Gas to purchase the gas commodity and midstream services and the revenue collected by Terasen Gas through the gas cost recovery component of rates. CCRA is designated to capture and account for costs and recoveries associated with the baseload supply through gas commodity rates whereas MCRA is associated with the midstream resources required to balance the daily load and meet design day. The MCRA costs are made up of seasonal commodity purchases, transport costs and storage costs.

CCRA rates are reviewed on a quarterly basis, and typically reset when the commodity recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. Generally, when commodity rates are reset, the new rate is designed to recover, or refund, over the next 12 months any existing CCRA account balance, along with any under or over recovery of commodity costs forecast to occur over the next 12-month period.

Midstream rates are reviewed on a quarterly basis and, under normal circumstances, midstream rates are adjusted on an annual basis with a January 1 effective date. Generally, when midstream rates are reset for the upcoming calendar year, the new rate is designed to recover, or refund, over the next 12 months any existing MCRA account balance, along with any under or over recovery of midstream costs forecast to occur over the next 12-month period.

The Terasen Gas Utilities customers, along with customers of other Canadian and US utilities, benefit from these deferral accounts given that they potentially smooth out the volatility in commodity rate changes and volume related variances.

88.2 In a table for total 2009 revenue requirements including cost of gas, please itemize the components (i.e. cost of gas, O&M, taxes, interest, earnings, etc.) by amount and percentage of total. For each of the items indicate how much is covered by a deferral account. Also include tabulation subtotals for revenues with and without deferral account protection.

Response:

	Revenue Requirement		Revenue Requirement Covered by Deferred Charges			Revenue Requirement Not Covered by Deferred Charges	
Revenue Requirement Item	**$000's**	**% of Total**	**% Covered by Deferred Charges**	**($000's)**	**% of Total Revenue Requirement**	**($000's)**	**% of Total Revenue Requirement**
Cost of Gas	$ 1,187,999	70.3%	100.0%	$ 1,187,999	70.3%	$ -	0.0%
Operation & Maintenance Expenses	174,942	10.4%	4.9%	8,570	0.5%	166,372	9.8%
Property and Sundry Taxes	47,593	2.8%	100.0%	47,593	2.8%	-	0.0%
Depreciation and Amortization	89,685	5.3%	0.0%	-	0.0%	89,685	5.3%
Other Operating Revenue	(23,444)	-1.4%	4.3%	(1,000)	-0.1%	(22,444)	-1.3%
Income Taxes *	26,331	1.6%	0.0%	-	0.0%	26,331	1.6%
Interest	110,953	6.6%	94.4%	104,691	6.2%	6,262	0.4%
Equity Earned Return	75,360	4.5%	0.0%	-	0.0%	75,360	4.5%
Total Revenue Requirement	**1,689,419**	**100.0%**		**1,347,853**	**79.8%**	**341,566**	**20.2%**
Total Delivery Margin Revenue Requirement	**501,420**	**100.0%**		**159,854**	**31.9%**	**341,566**	**68.1%**

* Since deferral accounts are maintained on a net-of-tax basis, to the extent any amounts were charged to or credited to deferral accounts, there would be an offsetting income tax impact

88.2.1 For those costs/revenues not covered by a deferral account, please provide for the last five fiscal years the forecast and actual.

Response:

Please refer to Attachment 88.2.1.

89.0 Reference: Exhibit B-1, Tab 1, p. 3, par. 2, line 8 Business risk – government policy

89.1 Please provide a copy of the document referenced by footnote 2. The web link does not appear to work.

Response:

Please see Attachment 89.1.

Attachment 4.1

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 1510 *, Approved and Ordered* DEC. 13.1995

I hereby certify that the following is a true copy of a Minute of the Honourable the Executive Council of the Province of British Columbia approved by His Honour the Lieutenant-Governor.

Order-inCouncil Custodian

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Vancouver Island Natural Gas Pipeline Special Direction is issued to the British Columbia Utilities Commission.

Anne Edwards
Minister of Energy, Mines and Petroleum Resources

M Harcourt
Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- Vancouver Island Natural Gas Pipeline Act, s. 7 (4)

Other (specify):-

December 8, 1995

1970/95/11/aaa

SPECIAL DIRECTION
TO THE
BRITISH COLUMBIA UTILITIES COMMISSION

PART 1
PRELIMINARY & GENERAL MATTERS

1.1 Definitions

"**Annual CPI**" means the percentage increase in the CPI over the most recent twelve month period for which information is available at any particular time when New Customer rates are approved pursuant to Section 2.7;

"**Annual Revenue Deficiency**" and "**Revenue Deficiency Deferral Account**" shall have the meanings given to these terms in Section 2.10;

"**BCUC**" means the British Columbia Utilities Commission;

"**Canada Repayable Contribution**" and "**British Columbia Repayable Contribution**" shall each have the meanings given to these terms in an agreement entered into among Her Majesty the Queen in Right of Canada, the Province, and PCEC substantially in the form of the Pacific Coast Energy Pipeline Agreement attached as Schedule 3 to the Vancouver Island Natural Gas Pipeline Agreement Approval Order.

"**CPI**" means the monthly consumer price index for Victoria, British Columbia for all items, as published by Statistics Canada;

"**Centra**" means, at the effective date of this Special Direction, collectively, Centra Gas British Columbia Inc., Centra Gas Vancouver Island Inc. and Centra Gas Victoria Inc., and thereafter means such other company or companies that may from time to time own and operate all or any part of the Centra Distribution System;

"Centra Distribution System" means the gas distribution systems of Centra that were connected to the Pipeline as of the effective date of this Special Direction, together with any extensions thereof;

"Class "A" Instruments" means cumulative redeemable preferred shares issued by Centra, having attached the right to receive dividends at an annual rate determined by Centra, based on the issue price of such shares, not exceeding 58% of the Current 5 Year Canada Rate at the date of iseuance, plus 275 basis points and having such other terms (including provision for a dividend reset date) as are set out in the form of Class "A" Instrument attached as Schedule "A" to this Special Direction, or as may be otherwise determined by Centra and approved by the BCUC;

"Class "B" Instruments" means promissory notes or other debt instruments issued by Centra bearing interest at an annual rate determined by Centra, not exceeding the Current 5 Year Canada Rate at the date of issuance, plus 275 basis points and having such other terms (including provision for an interest reset date) as are set out in the form of Class "B" Instrument attached as Schedule "B" to this Special Direction, or as may be otherwise determined by Centra and approved by the BCUC;

"Current 5 Year Canada Rate" means, on any particular date, the most recent monthly rate published by the Bank of Canada as the benchmark yield on 5 year Government of Canada Bonds, as set out in column B14069 of the most recent release of the Bank of Canada Review;

"Interruptible Incentive Payments" means those payments to be made by the Province to PCEC in accordance with Sections 2.06, 2.07, and 2.08 of the Vancouver Island Natural Gas Pipeline Agreement;

"Joint Venture" means those corporations or other entities which, from time to time, own and operate the seven pulp mills that were being served by the Pipeline at the effective date of this Special Direction (the "**Mills**"), and which are operating as a joint venture for the purpose of obtaining gas transportation service from PCEC for the Mills;

"**Long Canada Rate**" means for any particular year, the Government of Canada long term bond reference rate used by the BCUC to determine return on equity for public utilities for that year and, in the event that such a reference rate does not exist for any particular year, then Long Canada Rate shall mean the rate implied by an independent consensus forecast of Government of Canada long term bond yields for that year that is approved by the BCUC;

"**PCEC**" means Pacific Coast Energy Corporation, or such other company that may from time to time own and operate the Pipeline;

"**Pipeline**" means the Vancouver Island natural gas pipeline, as described in the Energy Project Certificate issued to PCEC;

"**Province**" means Her Majesty the Queen in Right of the Province of British Columbia;

"**Rate Stabilization Facility**" means the financial facility continued in respect of Squamish Gas under the Rate Stabilization Facility Continuation Agreement;

"**Rate Stabilization Facility Continuation Agreement**" means an agreement between the Province and PCEC substantially in the form of the agreement attached as Schedule 2 to the Vancouver Island Natural Gas Pipeline Agreement Approval Order;

"**Royalty Revenue Payments**" means those payments to be made by the Province to Centra in accordance with Sections 2.03 and 2.04 of the Vancouver Island Natural Gas Pipeline Agreement and, in the event that the Pipeline and the Centra Distribution System are owned and operated by a single legal entity, "Royalty Revenue Payments" shall also include the Interruptible Incentive Payments;

"**Single Entity**" means a single legal entity which owns and operates both the Centra Distribution System and the Pipeline;

"**Squamish Gas**" means, at the effective date of this Special Direction, Squamish Gas Co. Ltd., and thereafter means such other company or companies that may, from time to time, own and operate the Squamish Gas Distribution System;

"**Squamish Gas Distribution System**" means the gas distribution system of Squamish Gas that was in existence as of the effective date of this Special Direction, together with any extensions thereof;

"**Squamish Gas Transportation Service Agreement**" means that Agreement between PCEC and Squamish Gas dated April 1, 1990;

"**Squamish Rate Stabilization Agreement**" means that Agreement between the Province and Squamish Gas dated July 9, 1992;

"**Utilities**" means, collectively, PCEC, Centra, and Squamish Gas, and "**Utility**" means any one of them;

"**Vancouver Island Natural Gas Pipeline Agreement**" means an agreement among the Province, Westcoast Energy Inc., PCEC and Centra substantially in the form of the agreement attached as Schedule 1 to the Vancouver Island Natural Gas Pipeline Agreement Approval Order.

1.2 Schedules

The following Schedules are a part of this Special Direction:

Schedule "A" - FORM OF CLASS "A" INSTRUMENT

Schedule "B" - FORM OF CLASS "B" INSTRUMENT

Schedule "C" - INITIAL NEW CUSTOMER RATE SCHEDULE

Schedule "D" - DESIGNATED ROYALTY ADJUSTED COST OF GAS

Schedule "E" - EXAMPLES OF CALCULATION OF REVENUE DEFICIENCY DEFERRAL ACCOUNT BALANCE

Schedule "F" - JOINT VENTURE TRANSPORTATION SERVICE AGREEMENT

Schedule "G" - CENTRA TRANSPORTATION SERVICE AGREEMENT

Schedule "H" - PACIFIC COAST ENERGY CORPORATION GENERAL TERMS AND CONDITIONS

1.3 Effective Date, Special Direction No. 5 and Duration

This Special Direction shall become effective and supersede and replace Special Direction No. 5 (established pursuant to Order in Council No. 990, July 11, 1991) when the Secretary of the BCUC receives a written notice from each of the parties to the Vancouver Island Natural Gas Pipeline Agreement confirming that such Agreement has been executed and delivered. This Special Direction shall cease to have any application after the latest of:

(a) the time when the balance of the Revenue Deficiency Deferral Account has been reduced to zero; and

(b) the date of the expiration or earlier termination of the Joint Venture Transportation Service Agreement appended as Schedule "F", which date shall in no event be later than January 1, 2011; and

(c) the date of the termination of the Squamish Gas Transportation Service Agreement.

1.4 General

The BCUC shall regulate the Utilities and fix the rates charged by the Utilities in accordance with the requirements of this Special Direction , and in accordance with the requirements of the Utilities Commission Act and such regulatory principles that are otherwise applicable to the Utilities from time to time that are not inconsistent with this Special Direction. In the event of any inconsistency between this Special Direction and any requirement of the Utilities Commission Act or any regulatory principles that would otherwise be applicable to the Utilities, the BCUC shall follow the provisions of this Special Direction. For greater certainty, the BCUC shall not apply any provisions of the Utilities Commission Act (including, without limitation, Sections 64, 65, 66, and 67) in any manner which has the effect, directly or indirectly, of eliminating or varying any rates that have been specified in, or determined in accordance with, this Special Direction, or eliminating or varying any other determination or matter provided for herein.

PART 2
DIRECTION RESPECTING CENTRA

2.1 General Direction With Respect to Rates

Rates, changes in rates, changes in customer classifications or other rate design matters, shall be filed with and approved by the BCUC on an annual basis or such other periodic basis as the BCUC may determine.

2.2 Pioneer and New Customers

All customers of Centra (other than customers who have entered into long term commercial gas supply contracts that have been individually approved by the BCUC) shall be categorized as either a **"Pioneer Customer"** or a **"New Customer"** based upon the criteria set out below. Such categories shall be for the purpose of fixing rates for the period from the effective date of this Special Direction to December 31, 2003, in the case of Pioneer Customers within the ACR-2 customer rate class, and for the period from the effective date of this Special Direction to December 31, 2002, in the case of all other Pioneer and New Customers.

(a) Pioneer Customer

Any customer of Centra:

(i) who applies for service as a Pioneer Customer prior to February 13, 1996, and whose application is accepted by Centra; and

(ii) to whom gas has been delivered within 60 days after a service line has been provided to that customer by Centra,

shall be a Pioneer Customer for the purpose of service to that customer at the location applied for. A customer shall cease to be classified as a Pioneer Customer:

(iii) if the customer enters into an agreement with Centra, releasing its entitlement to be classified as a Pioneer Customer; or,

(iv) if the customer enters in a gas supply contract with a party other than Centra, the other party provides gas for the customer, and Centra is subsequently required to provide the customer's gas supply.

(b) New Customer

Any customer of Centra who does not satisfy the requirements for classification as a Pioneer Customer, or any customer who has released its entitlement to be classified as a Pioneer Customer, shall be classified as a New Customer. The BCUC may require Centra to develop policies for approval by the BCUC for the purpose of determining whether there has been a change that would result in any particular customer not being entitled to service as a Pioneer Customer.

2.3 Closing of Pioneer Customer Rate Classes

The customer rate classes for Pioneer Customers shall be the SGS-1, SGS-2, ACR-1, ACR-2, LGS-1, LGS-2, and LGS-3 customer rate classes as defined in the rate schedule filed by Centra with the BCUC and in effect as of January 1, 1995. Entry into the Pioneer

Customer rate classes shall be closed in accordance with the definitions in paragraph 2.2, however, a customer within a particular Pioneer Customer rate class may move from one Pioneer Customer rate class to another, in accordance with the applicable terms and conditions of service, so long as the customer is continuing to receive service at the same location.

2.4 Rates for Pioneer Customers Within the ACR-2 Customer Rate Class 1995 - 2003

The BCUC shall fix the rates charged by Centra to Pioneer Customers within the ACR-2 rate class for the period from the effective date of this Special Direction to December 31, 2003, independently from Centra's cost of service and in accordance with the applicable provisions of the rate schedule filed by Centra with the BCUC and in effect as of January 1, 1995. In order to apply such provisions, the BCUC shall require Centra to determine the Vancouver rack price for No. 2 fuel oil for such period, and employing such methods, as may be approved by the BCUC from time to time.

2.5 Other Pioneer Customer Rates 1995 - 2001

The BCUC shall fix the rates charged by Centra to Pioneer Customers (other than those within the ACR-2 customer rate class) for the period from the effective date of this Special Direction to December 31, 2001, in accordance with the following directions.

(a) Market Monitoring and Determination of Competitive Energy Prices

The BCUC shall require Centra to monitor the competitive fuel oil markets within its service area for such period, and employing such methods, as may be approved by the BCUC from time to time, and Centra shall be required to provide the results of its market monitoring to the BCUC and, based thereon, the BCUC shall determine the market price at which fuel oil would be available to a Pioneer Customer within each applicable rate class and the price or prices so determined shall be the "Competitive Fuel Price" for the applicable period and customer class. The BCUC shall also determine the price equal to 67% of the B.C. Hydro Trailing Block Rate for residential service available to Pioneer Customers and the price or prices so determined (expressed in dollars per gigajoule equivalent) shall be the "Discounted Electricity Price" for the applicable period.

(b) SGS-1, SGS-2, ACR-1, LGS-1, LGS-2 and LGS-3 Rates

Rates for Pioneer Customers within the SGS-1, SGS-2, ACR-1, LGS-1, LGS-2 and LGS-3 rate classes shall be determined independently from Centra's cost of service and shall be equal to the lesser of:

(i) the applicable Competitive Fuel Price, less the applicable Fuel Oil Discount as set out in Table 1 below; or

(ii) the applicable Discounted Electricity Price.

Table 1

FUEL OIL DISCOUNT

Year	Discount
1995	13%
1996	12%
1997	11%
1998 - 2001	10%

2.6 Other Pioneer Customer Rates 2002

The BCUC shall fix the rates charged by Centra to Pioneer Customers (other than those within the ACR-2 customer rate class) during 2002 independently from Centra's cost of service at the lesser of the rate that would be determined under Section 2.5(b)(i) (given a Fuel

Oil Discount of zero) and the rate for New Customers set in accordance with Section 2.7.

2.7 New Customer Rates 1995 - 2002

The BCUC shall fix the rates charged by Centra to New Customers for the period from the effective date of this Special Direction to December 31, 2002, in accordance with the following directions.

(a) General Principles

Rates should, to the greatest extent reasonably possible, be consistent with the goals of simplicity, equity between the various New Customer rate classes and the optimization of revenue to Centra. Centra is to be allowed flexibility in structuring its rates and, where it is determined by the BCUC to be appropriate, rates may be structured to include demand charges and commodity charges. The foregoing general principles shall be subject to the more specific directions set out below.

(b) Initial New Customer Rate Schedule

Rates charged to New Customers for the period from the effective date of this Special Direction to December 31, 1996, shall be those rates set out in the Initial New Customer Rate Schedule that is attached as Schedule "C" to this Special Direction.

(c) Rate Ceilings

Subject only to paragraph (d) below, the rates that are approved for each year from January 1, 1997, to December 31, 2002, shall be subject to rate ceilings determined in accordance with the following directions:

(i) A rate shall not be approved if it would result in an average customer (as described by reference to volume in Table 2 below) in any particular customer rate class being charged an effective unit price that would be greater than the effective unit price (determined as set out in subparagraph (iii) below) charged to that average customer in the immediately preceding year, increased by the allowable percentage increase set out in Table 3 below.

Table 2

AVERAGE ANNUAL CUSTOMER CONSUMPTION

SGS 11	70 GJ
SGS 12	270 GJ
LGS 11	945 GJ
LGS 12	2844 GJ
LGS 13	18793 GJ

Table 3

ANNUAL ALLOWABLE PERCENTAGE POINT INCREASE

1997	8%	2000	Annual CPI + 1%
1998	6%	2001	Annual CPI + 1%
1999	Annual CPI + 1%	2002	Annual CPI + 1%

(ii) If the increase in the effective unit price for an average customer in any particular customer rate class in any particular year described above is less than the allowable increase, then the difference may be carried forward to the next year so that the allowable percentage point increase for that customer rate class in the next year is increased accordingly. To the extent that the increased allowable percentage point increase is not utilized it may be carried forward in a similar fashion to subsequent years.

(iii) For the purpose of determining the rate ceilings, effective unit prices shall be calculated by taking into account all relevant demand and commodity charges, but shall not include any increase or decrease in charges which resulted from Passthrough Costs in accordance with paragraph (d) below and shall not include the charge described in Rider A as set out in Schedule "C" or any special service rates in the nature of those approved by the BCUC as of the effective date of this Special Direction. For greater certainty, it is intended that the rate ceilings be calculated so that any decrease or increase in Centra rates resulting from a Passthrough Cost in any particular year does not increase or decrease the rate ceiling applicable to a subsequent year.

(iv) Because the limitations on rate increases are governed by the effective unit price payable by average customers for each of the various customer rate classes, the effective unit prices actually payable by some New Customers may be subject to greater increases than described in this paragraph (c).

(v) If the BCUC approves a change to Centra's customer rate classes, then any resulting changed or additional customer rate class shall be subject to the limitations on rate increases described in this paragraph (c). The BCUC shall make any determination of average customer volumes, or any other matter that is necessary in order to calculate the effective unit price for an average customer of any changed or additional customer rate class.

(d) Passthrough Costs and the New Customer Rate Balancing Account

If, in any particular year, "Passthrough Costs" (meaning only those costs described below) have either increased or decreased, then notwithstanding the limitation on rate increases set out in paragraph (c) the rates charged by Centra to New Customers may be varied in accordance with Section 67(4) of the Utilities Commission Act and the following directions.

(i) Passthrough Costs for any particular year shall be determined by the BCUC as the aggregate of the following amounts:

(A) the change in the cost of service to New Customers in a particular year as a result of a change in Federal, Provincial, or Municipal tax rates;

(B) a change in the cost of service to New Customers as a result of a material and uncontrollable change in costs associated with a program established by any governmental or regulatory authority;

(C) the change in the cost of service to New Customers as a result of a difference between the "Actual Royalty Adjusted Cost of Gas" for a particular year, and the Designated Royalty Adjusted Cost of Gas for that year as set out in Schedule "D". The "Actual Royalty Adjusted Cost of Gas" for a particular year shall be determined as follows. Firstly, the BCUC shall determine Centra's cost of gas for the year being all of the costs incurred by Centra, and approved by the BCUC, to obtain gas for customer use and system use (including line losses, unaccounted for gas, and fuel requirements), including, without limitation:

(1) the purchase price of gas;

(2) gathering, processing, transportation, and storage costs; and

(3) costs of any arbitration relating to Centra's gas supply arrangements;

but excluding:

(4) commissions and gas management fees paid in connection with the purchase of gas;

(5) any toll paid by Centra to PCEC or any other cost associated with the transportation of gas through the Pipeline; and

(6) any cost associated with the transportation of gas from the point of interconnection of the pipeline systems of Westcoast Energy Inc. and BC Gas Utility Ltd. near Huntingdon (the "**Huntingdon Point of Interconnection**"), to the point of interconnection of the pipeline systems of BC Gas Utility Ltd. and PCEC in Coquitlam.

Secondly, the cost of gas for the year shall be reduced by the total of all

Royalty Revenue Payments for that year. Thirdly, the resulting number shall be divided by the total volume of gas delivered to Centra at the Huntingdon Point of Interconnection. For greater certainty, a change to the cost of service to New Customers as a result of a variation in the cost of gas as described herein may be either a negative or a positive amount.

(ii) Passthrough Costs shall include only that portion of increased costs that can be reasonably allocated to New Customers. Any portion of an increased cost that is allocated to the cost of service to other customers of Centra, together with other costs that would be allowed by the BCUC under Section 67(4) of the Utilities Commission Act, but which do not otherwise satisfy the definition of Passthrough Costs, shall be taken into account in determining whether Centra has incurred an Annual Revenue Deficiency, but shall not affect the rate ceilings applicable to Centra's New Customers.

(iii) Passthrough Costs for a particular year shall be recorded in a "New Customer Rate Balancing Account", which is a notional account for the purpose of determining adjustments to New Customer rates. The BCUC shall determine the manner in which positive or negative balances affect rates by taking into account the following objectives. Firstly, the impact of the variable nature of gas costs on New Customer rates should be minimized. Secondly, Centra, to the extent possible, should be able to increase its rates to New Customers by such amounts as are commensurate with any positive balance within the New Customer Rate Balancing Account that may exist from time to time.

(iv) The BCUC may require Centra to reduce the rates charged to New Customers in the event that the BCUC determines that there is a significant negative balance accumulating within the New Customer Rate Balancing Account that is not likely to be offset within a reasonable period of time.

2.8 Customer Rates 2003 and After

The BCUC shall fix the rates charged by Centra to its customers for the period beginning January 1, 2003, in the case of all customers other than those within the ACR-2 customer rate class, and January 1, 2004, in the case of customers formerly within the ACR-2 customer rate class, so that Centra is able to recover its cost of service in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within British Columbia.

2.9 Gas Supply Hedging Arrangements and Transportation and Sales Service

Centra may use gas supply hedging arrangements, the terms and conditions of which have been approved by the BCUC, in order to manage the risk associated with the Revenue Deficiency Deferral Account. Centra shall file with the BCUC, in accordance with the requirements specified by the BCUC from time to time, transportation rates that shall be generally available for Centra's large commercial customers. Such rates shall be available in accordance with such terms and conditions as are from time to time determined by Centra and approved by the BCUC. If requested by Centra, such terms and conditions shall include a requirement that any customer who is purchasing gas from Centra at the time the terms and conditions are approved or who thereafter enters into a gas purchase agreement with Centra, shall not be permitted to switch to transportation service prior to December 31, 2002.

2.10 Cost of Service and Revenue Deficiencies

Subject to Part 4 of this Special Direction, the BCUC shall determine Centra's cost of service and shall make the various associated determinations, all as described in, and in accordance with, the following directions.

(a) General Principles

For each year in the period beginning January 1, 1996, Centra shall be regulated on a forecast test year basis and shall be required to apply to the BCUC for approval of its:

(i) cost of service for each year and in conjunction therewith the BCUC shall determine the allowable capital additions to be made during such year and such other matters as the BCUC may deem appropriate for the determination of Centra's cost of service; and

(ii) projected revenue for such year inclusive of all Royalty Revenue Payments payable by the Province in respect of that year.

(b) Rate Base, Revenue Deficiency Deferral Account Balance and Cost of Service 1991 - 1995

The following amounts shall be determined in accordance with the Vancouver Island Natural Gas Pipeline Agreement and shall be set forth in notices delivered by the Province to the BCUC pursuant to Article 9 thereof:

(i) net plant in service as of December 31, 1995, determined as the aggregate of:

(A) net plant in service as of December 31, 1994, of $211,474,000, less $90,000,000; and

(B) additions to net plant in service during 1995 which shall be determined by taking gross additions made during 1995 and adjusting for disposals and depreciation in 1995;

(ii) the Annual Revenue Deficiency for 1995;

(iii) the balance of the Revenue Deficiency Deferral Account as of December 31, 1995;

(iv) Centra's cost of service for the period October 1, 1991, to December 31, 1991 and each year from January 1, 1992 to December 31, 1995; and

(v) work in progress as of December 31, 1995.

Centra's rate base as of December 31, 1995, or any time thereafter, shall be:

(vi) the amount specified in paragraph (i) above; plus

(vii) an allowance for working capital as determined and approved by the BCUC from time to time; plus

(viii) the capital cost of any additions to Centra's Distribution System made after December 31, 1995 as determined and approved by the BCUC from time to time; plus

(ix) deferred charges and other miscellaneous rate base items (which shall in no event include any amount of the Revenue Deficiency Deferral Account or any amount that would change the amount for the net plant in service as of December 31, 1995) as determined and approved by the BCUC from time to time; less

(x) accumulated depreciation and disposals for the period after December 31, 1995, as determined and approved by the BCUC from time to time.

(c) <u>Deemed Equity</u>

Subject to paragraph (e), the equity component of Centra's rate base:

(i) shall be deemed to be 35% for each year from January 1, 1996, to December 31, 2002, and for greater certainty the balance of Centra's rate base shall be deemed to be financed by debt; and

(ii) for the period after December 31, 2002, shall be such percentage of Centra's rate base that is determined to be appropriate in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within British Columbia.

(d) <u>Return on Equity</u>

The return on the equity component of Centra's rate base shall be the Long Canada Rate plus 375 basis points for each year from January 1, 1996, to December 31, 2002, and thereafter shall be such return that is determined to be appropriate in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within British Columbia.

(e) <u>Debt Financing of Rate Base</u>

The level of deemed equity and the return allowed thereon that are stipulated in paragraphs (c) and (d) may be varied by the BCUC for any year from January 1, 1996, to December 31, 2002, if:

(i) the actual level of debt financing of Centra (excluding Class "B" Instruments that are actually issued to finance all or any portion of the Revenue Deficiency Deferral Account balance) exceeds 65% of the rate base that the BCUC has determined for Centra; and

(ii) the BCUC determines that this level of debt financing is adversely affecting the cost of debt for the purpose of determining cost of service.

(f) <u>Determination of Revenue Deficiency Deferral Account Balance</u>

The BCUC shall determine the amount recorded in Centra's Revenue Deficiency Deferral Account, which amount shall equal, at any particular time:

(i) the total of all Annual Revenue Deficiencies incurred on or before that time; plus

(ii) the total amount of Class "A" Instruments and Class "B" Instruments that are deemed to have been issued pursuant to paragraph 2.10(h)(v)B(2) on or before that time; less

(iii) the total amount of Class "A" Instruments and Class "B" Instruments that are deemed to have been redeemed or repaid pursuant to paragraph 2.10(i) on or before that time.

"**Annual Revenue Deficiency**" for the 1995 year is the amount described in paragraph 2.10(b)(ii) and for any particular year after December 31, 1995 is the amount, if any, by which Centra's "Adjusted Cost of Service" exceeds Centra's actual revenues relating to the Centra Distribution System (including Royalty Revenue Payments) for that year.

"**Adjusted Cost of Service**" means Centra's cost of service as approved by the BCUC on a forecast test year basis, excluding any amount for the amortization of Class "A" Instruments or Class "B" Instruments pursuant to paragraph 2.10(j) and subject to adjustments for variations as described below. BCUC approved variations (which may be either an increase or a decrease) between actual and forecast costs shall be taken into account in the determination of Adjusted Cost of Service, however, the BCUC shall not:

(iv) approve a variation between Centra's actual and forecast operating and maintenance expenses unless the variation was caused by a factor over which Centra had no effective control; and

(v) make any adjustment after the end of a particular year to the Long Canada Rate used to determine return on equity for that year.

For the purpose of illustration only, examples of the determination of Annual Revenue Deficiency and Adjusted Cost of Service for the purpose of determining the balance of the Revenue Deficiency Deferral Account are attached as Schedule "E" to this Special Direction.

(g) Effect of Annual Revenue Deficiencies on Rate Base and Cost of Service

The balance of the Revenue Deficiency Deferral Account, or any amount relating to the Annual Revenue Deficiency for any particular year, shall not at any time be included within Centra's rate base. Except as specifically allowed by paragraphs 2.10(h) and 2.10(j), Centra's cost of service for the purpose of determining the rates to be charged to Centra's customers shall not include any cost of financing the Revenue Deficiency Deferral Account balance, and shall not include any amount for the amortization, reduction, or recovery of the Revenue Deficiency Deferral Account balance.

(h) <u>Deemed Financing Costs That Are To Be Included Within the Cost of Service</u>

The amount recorded in the Revenue Deficiency Deferral Account shall be deemed to be financed by Class "A" Instruments, or, in the circumstances provided below, by Class "B" Instruments. Centra's cost of service for any particular year shall include the interest and dividends, as the case may be, that are payable in respect of that year on the Class "A" Instruments and the Class "B" Instruments that are deemed to be outstanding during that year. The amount of such interest and dividends shall be determined in accordance with the following directions.

(i) Unless a determination is made under paragraph (ii), the amount recorded in the Revenue Deficiency Deferral Account shall be deemed to be financed by Class "A" Instruments.

(ii) When the BCUC approves Centra's forecast cost of service the BCUC shall determine whether it would be appropriate to deem the amount recorded in the Revenue Deficiency Deferral Account, or any particular portion thereof, to be financed by Class "B" Instruments.

(iii) A determination under paragraph (ii) may only be made if the BCUC determines that the financing by Class "B" Instruments will not have an impact on Centra's cost of service for the forecast test year and subsequent years that would, on a cumulative basis, result in an adverse impact on the Revenue Deficiency Deferral Account that would have to be recovered through rates charged to customers.

(iv) To the extent that the BCUC deems any portion of the balance of the Revenue Deficiency Deferral Account to be financed by Class "B" Instruments which has previously been deemed to be financed by Class "A" Instruments, the Class "B" Instruments shall be deemed to have been converted from Class "A" Instruments in accordance with the terms and conditions contained in the form of Class "A" Instrument attached as Schedule "A". To the extent that the BCUC deems any portion of the balance of the Revenue Deficiency Deferral Account to be financed by Class "A" Instruments which has previously been deemed to be financed by Class "B" Instruments, the Class "A" Instruments shall be deemed to have been converted from Class "B" Instruments in accordance with the terms and conditions contained in the form of Class "B" Instrument attached as Schedule "B".

(v) The instruments that are deemed to be issued to finance any particular year's Annual Revenue Deficiency shall be deemed:

(A) to be issued on June 30th of the year following the year in which the Annual Revenue Deficiency was incurred for the purpose of determining the dividend or interest rate payable pursuant to such instruments;

(B) to be issued in an aggregate amount equal to the sum of:

(1) the Annual Revenue Deficiency for the year; and

(2) an additional amount to take into account Centra's cost of financing the Annual Revenue Deficiency during the year in which it arose. This additional amount shall equal the

interest or dividends, as the case may be, payable for a 6 month period, under the instruments deemed to be issued in respect of the amount in subparagraph (1) above; and

(C) to be issued on January 1 of the year following the year in which the Annual Revenue Deficiency was incurred, for the purpose of determining when interest or dividends begin to accrue and become payable pursuant to such instruments.

(i) <u>Deemed Redemption or Repayment of Instruments for the Determination of the Balance of the Revenue Deficiency Deferral Account</u>

If Centra's actual revenues relating to the Centra Distribution System for any particular year would exceed what would otherwise be Centra's Adjusted Cost of Service for that year, the BCUC shall deem Centra to redeem Class "A" Instruments or repay Class "B" Instruments at the midpoint of that year to the extent necessary to cause Centra's Adjusted Cost of Service to equal such revenues. The instruments that are deemed to be redeemed or repaid shall be those instruments which have a dividend or interest reset date, as defined in the terms and conditions applicable to the instrument, which is closest to the date of deemed redemption or repayment.

(j) <u>Deemed Redemption or Repayment of Instruments for the Determination of Cost of Service and Setting of Rates</u>

For each year beginning January 1, 2003, the cost of service of Centra that is approved by the BCUC for the purpose of determining the rates to be charged to Centra's customers shall include an amount for the deemed redemption of Class "A" Instruments or repayment of Class "B" Instruments that the BCUC determines to be appropriate in order to amortize the balance of the Revenue Deficiency Deferral Account over the shortest period reasonably possible, having regard for Centra's competitive position relative to alternative energy sources and the desirability of reasonable rates.

2.11 Assistance for Financing Requirements

The BCUC shall not apply Paragraph 3 of BCUC Order G-16-90 (the "Order") in any way that would require Centra to obtain assistance in regard to its debt/equity financing requirements from Westcoast Energy Inc., or from any corporation that is a parent, grandparent or successor, as these terms are used in Paragraph 3 of the Order, other than what is provided for in the Vancouver Island Natural Gas Pipeline Agreement.

PART 3
DIRECTION RESPECTING PCEC

3.1 Cost of Service

Subject to Part 4 of this Special Direction, the BCUC shall determine PCEC's cost of service in accordance with the following directions:

(a) Rate Base and Cost of Service 1991 - 1995

The following amounts shall be determined in accordance with the Vancouver Island Natural Gas Pipeline Agreement and shall be set forth in notices delivered by the Province to the BCUC pursuant to Article 9 thereof:

(i) PCEC's net plant in service as of December 31, 1995, determined as the aggregate of:

(A) PCEC's net plant in service as of December 31, 1994, of $192,120,673, less $30,000,000; and

(B) PCEC's additions to net plant in service during 1995 which shall be determined by taking gross additions made during 1995 and adjusting for disposals and depreciation in 1995;

(ii) PCEC's cost of service for each year from 1991 to December 31, 1995; and

(iii) work in progress as of December 31, 1995.

PCEC's rate base as of December 31, 1995, or any time thereafter, shall be:

(iv) the amount set out in paragraph (i); plus

(v) an allowance for working capital as determined and approved by the BCUC from time to time; plus

(vi) the capital cost of any additions to the Pipeline made after December 31, 1995 as determined and approved by the BCUC from time to time; plus

(vii) any amounts of the Canada Repayable Contribution or the British Columbia Repayable Contribution which have been repaid by PCEC; plus

(viii) deferred charges and other miscellaneous rate base items (which shall in no event include any amount that would change the amount for the net plant in service as of December 31, 1995) as determined and approved by the BCUC from time to time; less

(ix) accumulated depreciation and disposals for the period after December 31, 1995, as determined and approved by the BCUC from time to time.

(b) Adjustment to Cost of Service

For each year from January 1, 1996, to December 31, 2011, the return on the equity component of PCEC's rate base that would have been otherwise approved by the BCUC shall be reduced by the amount of $1,867,000. Such reduction shall not be recovered in whole or in part, directly or indirectly, through rates or tolls in any manner whatsoever.

(c) Effect of Interruptible Incentive Payments

Interruptible Incentive Payments that are payable to PCEC in respect of any particular year shall be taken into account as revenues received by PCEC in partial recovery of its cost of service for that year.

(d) Effect of Monthly Toll Revenue - Squamish Gas

During the term of the Rate Stabilization Facility Continuation Agreement, the Monthly Toll Revenues determined pursuant to that agreement shall be taken into account as the only revenues received by PCEC in recovery of its cost of service with respect to the transportation and delivery of gas pursuant to the Squamish Gas Transportation Service Agreement.

3.2 Joint Venture Transportation Service Agreement

The BCUC shall approve the transportation service agreement between PCEC and the Joint Venture, including the transportation tolls provided for therein, that is attached as Schedule "F" to this Special Direction.

3.3 Squamish Gas Transportation Service Agreement

In regulating the transportation tolls charged by PCEC to Squamish Gas for service provided pursuant to the Squamish Gas Transportation Service Agreement, the BCUC shall apply the service rate provisions of that agreement for the period contemplated by the Squamish Rate Stabilization Agreement.

3.4 Centra Transportation Service Agreement

The BCUC shall approve the transportation service agreement between PCEC and Centra, including the transportation tolls provided for therein, that is attached as Schedule "G" to this Special Direction.

3.5 General Terms and Conditions

The "General Terms and Conditions" attached as Schedule "H" to this Special Direction shall be approved by the BCUC as the general contractual terms and conditions applicable to the transportation service agreements referred to in Sections 3.2 and 3.4 and to the other transportation service agreements that PCEC may enter into from time to time after the effective date of this Special Direction.

3.6 Variations of General Terms and Conditions and Joint Venture Transportation Service Agreement

The BCUC shall not amend, change, alter, or vary the transportation service agreement referred to in Section 3.2 or the General Terms and Conditions referred to in Section 3.5, if such amendment, change, alteration, or variation would have the effect of either:

(a) varying the transportation tolls or other amounts payable to PCEC for the services provided to the Joint Venture pursuant to that transportation service agreement; or

Premier Harcourt

(b) increasing or decreasing the Contract Demand for Firm Transportation Service determined in accordance with that transportation service agreement, or the quantities of Interruptible Offset Gas which the Joint Venture is entitled to receive pursuant to that transportation service agreement.

3.7 Rates and Transportation Tolls Otherwise Applicable to the Joint Venture, Squamish Gas, and Centra

For the purpose of fixing transportation tolls to be charged by PCEC other than as directed in Sections 3.2, 3.3 and 3.4, the BCUC shall, subject to the exception set out below, apply such regulatory principles that are generally applied by the BCUC from time to time to gas utilities operating within British Columbia. In no event whatsoever shall the rates or transportation tolls that are approved for the Joint Venture or Squamish Gas pursuant to this Section 3.7 include any amount for the recovery in whole or in part, directly or indirectly, of dividends or interest as described in paragraph 2.10(h), or for the amortization, reduction, or recovery of the Revenue Deficiency Deferral Account balance.

3.8 Allocation of PCEC's Cost of Service to Service Squamish Gas

The BCUC shall, upon receipt of a written request from the Province, determine that portion of PCEC's annual cost of service for any particular year that relates to providing transportation service to Squamish Gas during that year.

PART 4

DETERMINATION OF ANNUAL REVENUE DEFICIENCY, RATE BASE, CAPITAL STRUCTURE AND RETURN ON EQUITY WHERE THE PIPELINE AND THE CENTRA DISTRIBUTION SYSTEM ARE OWNED BY A SINGLE ENTITY

4.1 Annual Revenue Deficiencies

The BCUC shall determine Annual Revenue Deficiencies and the balance of the Revenue Deficiency Deferral Account for a Single

Entity in the manner set out in Section 2.10 based upon the actual revenue and the cost of service associated with both the Centra Distribution System and the Pipeline but without taking into account any revenue or costs that relate to any other business conducted, or assets owned, by the Single Entity.

4.2 Rate Base, Capital Structure and Return on Equity

A single rate base shall be determined for the Single Entity in accordance with the directions in paragraphs 2.10(b) and 3.1(a). Subject to Sections 4.3 and 4.4, for any particular year from January 1, 1996, to December 31, 2002:

(a) the equity component of the Single Entity's rate base shall be deemed to be 35% and, for greater certainty, the balance of the Single Entity's rate base shall be deemed to be financed by debt; and

(b) the return on the equity component of the Single Entity's rate base shall be the Long Canada Rate plus 362.5 basis points.

Subject to Section 4.3, after December 31, 2002, the capital structure and return on equity for the Single Entity shall be determined in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas transportation and distribution utilities operating within British Columbia.

4.3 Adjustment to Return on Equity

The reduction to the return on the equity component of PCEC's rate base that is described in paragraph 3.1(b) shall continue to be made to the return on the equity component of the rate base of the Single Entity.

4.4 Debt Financing of Rate Base

The level of deemed equity and the return allowed thereon that are stipulated in Section 4.2 may be varied by the BCUC for any year from January 1, 1996, to December 31, 2002, if:

(a) the actual level of debt financing of the Single Entity (excluding Class "B" Instruments that are actually issued to finance all or any portion of the Revenue Deficiency Deferral Account balance) exceeds 65% of the rate base that the BCUC has determined for the Single Entity; and

(b) the BCUC determines that this level of debt financing is adversely affecting the cost of debt for the purpose of determining cost of service.

4.5 Separate Records

The BCUC shall require that the Single Entity keep separate records relating to the Pipeline and the Centra Distribution System sufficient at all times to differentiate, where appropriate, between all activities related to the construction and operation of the Pipeline and the Centra Distribution System.

PART 5
DIRECTION RESPECTING SQUAMISH GAS

5.1 Customer Rates

The BCUC shall fix the rates charged by Squamish Gas to its customers in accordance with the Squamish Rate Stabilization Agreement during the period for which that agreement remains in effect and, thereafter, in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within British Columbia. In this regard, the BCUC shall have regard, during the period when the Squamish Rate Stabilization Agreement remains in effect, to the provisions in the "Binding Agreement", as that term is defined in the Squamish Rate Stabilization Agreement, notwithstanding any amendment or termination of the Binding Agreement subsequent to July 9, 1992.

5.2 Regulation and Other Determinations Pursuant to the Squamish Rate Stabilization Agreement

The BCUC shall regulate Squamish Gas, determine the cost of service of Squamish Gas, and make the various determinations required in order to implement the Squamish Rate Stabilization Agreement, all in accordance with the Squamish Rate Stabilization Agreement during the period for which that agreement is in effect.

Attachment 5.1

National Energy Board
Office national de l'énergie

Reasons for Decision

Trans Québec & Maritimes Pipelines Inc.

RH-1-2008

March 2009

Cost of Capital

Canada

National Energy Board

Reasons for Decision

In the Matter of

Trans Québec & Maritimes Pipelines Inc.

Cost of Capital for 2007 and 2008

RH-1-2008

March 2009

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Cat No. NE22-1/2009-3E
ISBN 978-1-100-11699-0

This report is published separately in both official languages. This publication is available upon request in multiple formats.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
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For pick-up at the NEB office:
Library
Ground Floor

Printed in Canada

© Sa Majesté la Reine du Chef du Canada 2009 représentée par l'Office national de l'énergie

N° de cat. NE22-1/2009-3F
ISBN 978-1-100-90696-6

Ce rapport est publié séparément dans les deux langues officielles. On peut obtenir cette publication sur supports multiples, sur demande.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
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Imprimé au Canada

Table of Contents

List of Figures

List of Tables

List of Appendices

Abbreviations

10^6m^3	Million cubic metres
$10^6m^3/d$	Million cubic metres per day
10^9m^3	Billion cubic metres
Act	*National Energy Board Act*
Alliance	Alliance Pipeline Ltd.
ATWACC	After-Tax Weighted-Average Cost of Capital
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Board or NEB	National Energy Board
bps	Basis points
Canaport	Canaport LNG Terminal
CAPM	Capital asset pricing model
CAPP	Canadian Association of Petroleum Producers
CBM	Coalbed methane
CGA	Canadian Gas Association
CGPC	Canadian Gas Potential Committee
Dawn	Dawn Hub
DBRS	Dominion Bond Rating Service
DCF	Discounted cash flow
Dth	Decatherm
ECAPM	Empirical capital asset pricing model
Enbridge	Enbridge Pipelines Inc.
EUB	Alberta Energy and Utilities Board*
ERP	Equity Risk Premium
FERC	Federal Energy Regulatory Commission (U.S.)

* on 1 January 2008 became the Energy Resources Conservation Board and the Alberta Utilities Commission

Gaz Métro	Gaz Métro Limited Partnership
GDP	Gross Domestic Product
GP	General Partner
IGUA	Industrial Gas Users Association
IRR	Internal rate of return
LDC	Local distribution company
LNG	Liquefied natural gas
LP	Limited partner
M&NP	Maritimes & Northeast Pipeline
Mainline	TransCanada Mainline natural gas transmission system
MLP	Master Limited Partnership
Moody's	Moody’s Investor Services
MRP	Market Risk Premium
NPV	Net present value
Ontario	Minister of Energy for the Province of Ontario
PNG	Pacific Northern Gas Ltd.
PNGTS	Portland Natural Gas Transmission System
Régie	Régie de l’énergie
ROE	Rate of return on common equity
S&P	Standard & Poor’s
Spectra	Spectra Energy Transmission
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada	TransCanada PipeLines Limited
Trans Mountain	Trans Mountain Pipe Line Company Ltd.
Tcf	Trillion cubic feet
U.S.	United States of America
Union	Union Gas Limited

WACC	Weighted-Average Cost of Capital
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc., carrying on business as Spectra Energy Transmission

Glossary of Terms

Basis point (bps)	One-hundredth of a percentage point, used in reference to interest rates or rates of return on equity
Beta	A measure of the systematic risk of a security, which estimates the extent to which a stock's price fluctuates more or less than average when the market fluctuates
Bond rating	A quality rating assigned by credit rating agencies as an indication of creditworthiness
Book value	The amount at which an item appears in the books of account and financial statements
Business risk	The risk attributed to the nature of a particular business activity (as distinct from financial risk); For pipelines, it typically includes supply, market, regulatory, competitive, and operating risks
Capital asset pricing model (CAPM)	A method used to estimate the cost of equity capital by comparing the return and risk characteristics of an individual company's shares with the market average
Capital attraction requirement	The aspect of the Fair Return Standard that requires that the return of a regulated utility permit incremental capital to be attracted to the enterprise on reasonable terms and conditions
Capital structure	The way in which a business is financed; generally expressed as a percentage breakdown of the types of capital employed
Coalbed methane	An unconventional form of natural gas that is trapped within the matrix of coal seams
Comparable investment requirement	The aspect of the Fair Return Standard that requires that the return of a regulated utility be comparable to the return available from the application of the invested capital to other enterprises of like risk
Competitive risk	The business risk that results from competition for customers at both the supply and market ends of a pipeline system
Conventional gas	Natural gas that is found in the reservoir and produced through a wellbore with known technology and where the drive for production is provided by expansion of the gas or by pressure from an underlying aquifer

Cost of service	The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, and return on rate base
Dawn Hub	An interchange, located in southern Ontario, where multiple pipelines interconnect and form a market centre
Deemed capital structure	A notional capital structure used for rate-making purposes that may differ from a company's actual capital structure
Depreciation	A non-cash expense charged against earnings to write off the cost of an asset during its estimated useful life
Discounted Cash Flow (DCF)	A method used for estimating the cost of common equity based on the expected dividend yield of the company's shares and the expected future dividend growth rate
Economic resources	That portion of the technical resources that can be developed economically under anticipated economic conditions
Embedded cost of debt	The weighted-average historical cost of long-term debt outstanding
Empirical CAPM (ECAPM)	A method used to estimate the cost of equity capital by comparing the return and risk characteristics of an individual company's shares with the market average. This method relies on a security market line that attempts to match more closely the results of empirical tests on the CAPM (higher intercept and smaller slope)
Fair Return Standard	A standard that must be examined when setting the return allowed to a regulated company; it is comprised of the comparable investment, financial integrity and capital attraction requirements
Financial integrity requirement	The aspect of the Fair Return Standard that requires that the return of a regulated utility enable the financial integrity of the regulated enterprise to be maintained
Financial risk	The risk inherent in a company's capital structure; financial risk increases as the proportion of debt increases
Flow-through tax methodology	A method of estimating income taxes payable for a period based on taxable income as opposed to accounting income
GH-1-97	NEB Proceeding on the TQM PNGTS Extension (Reasons for Decision dated April 1998)
Investment risk	The total of a company's business risk and financial risk

Market risk	The business risk that stems from the overall size of the market and the market share that a pipeline is able to capture
Market risk premium	Equity risk premium for the market as a whole (where the premium is the difference between the expected equity market return as a whole and a risk-free rate)
Operating risk	Risk to the income-earning capability that arises from technical and operational factors
Rate base	Amount of investment on which a return is authorized to be earned; it typically includes plant in service plus an allowance for working capital
Regulatory risk	Risk to the income-earning capability of the assets that arises due to the method of regulation of the company
Revenue requirement	Total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, and return on rate base
Return on rate base (return)	The return that a regulated company is authorized to earn on its approved rate base
RH-2-2004	NEB Proceedings on TransCanada's 2004 Mainline Tolls and Tariff Application (Phase I Reasons for Decision dated September 2004; Phase II Reasons for Decision dated April 2005)
RH-2-94	NEB Multi-Pipeline Cost of Capital Proceeding (Reasons for Decision dated March 1995)
RH-2-94 Formula	Formula used to determine the rate of return on common equity for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, as amended to eliminate rounding
RH-4-2001	NEB Proceeding on TransCanada's 2001-2002 Mainline Fair Return Application concerning cost of capital for the Mainline (Reasons for Decision dated June 2002)
Shale gas	A form of unconventional gas where the gas molecules are mainly trapped on the organic material in a host rock of fine-grained shale
Supply risk	Risk that the physical availability of economical natural gas volumes could affect a pipeline's income-earning capability

Tariff	The terms and conditions under which the services of a pipeline are offered or provided, including the tolls, the rules and regulations, and the practices relating to specific services
Technical resources	Natural gas resources estimated by having regard for the geological prospects in an area or basin and anticipated technology. They are the sum of cumulative production (portions already produced), reserves (portions discovered, but not produced) and future resources (portions still undiscovered), with all given as marketable volumes. Marketable volumes for the future resources are determined by applying the recovery factors and surface losses applicable to pools discovered in the past
Test Year	A forward looking 12-month period used for rate-making purposes
Tight gas	A form of non-conventional natural gas that is held in the pore space of a rock that has a lower permeability or ability to flow than usual for that type of rock
Ultimate potential	A term used to refer to an estimate of the marketable resources that will be developed in an area by the time that exploratory and development activity has ceased, having regard for the geological prospects of an area, known technology and economics. It includes cumulative production, remaining reserves, and future additions to reserves through extension and revision to existing pools and the discovery of new pools
Unconventional gas	Natural gas that is contained in a non-traditional reservoir rock that requires significant additional stimulus to allow gas flow; it may be that the gas is held by the matrix material such as coal, ice, or shale; or where the reservoir has an unusually low amount of porosity and permeability
Utilization rate	A rate determined by dividing system throughput by pipeline design capacity, expressed as a percentage

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* (Act) and the regulations made thereunder;

IN THE MATTER OF an application dated 17 December 2007 by Trans Québec & Maritimes Pipeline Inc. (TQM) pursuant to subsection 21(1), and Part IV of the Act;

AND IN THE MATTER OF National Energy Board Hearing Order RH-1-2008, dated 22 January 2008.

HEARD in Montréal, Quebec, on 23, 24, 25, 26, 29, 30 September 2008 and 1, 2, 3, 6, 7, 8 October 2008; and in Calgary, Alberta, on 20, 21, 22 October 2008;

BEFORE:

G. Caron	Presiding Member
R.R. George	Member
G.A. Habib	Member

Appearances	**Participants**	**Witnesses**
C.K. Yates, Q.C. L.-A. Leclerc D. Langen	Trans Québec & Maritimes Pipeline Inc.	S. Brett P. Cabana P.R. Carpenter J.J. Dueck A.M. Engen R.K. Girling A.L. Kolbe W.A. Langford P.J. Murphy B. Otis S. Pohlod J.H. Vander Weide M.J. Vilbert
N.J. Schultz	Canadian Association of Petroleum Producers	L.D. Booth J.D. Miller A. Safir
L.E. Smith, Q.C.	Canadian Gas Association	
P. Jeffrey	Industrial Gas Users Association	L.D. Booth P.G. Dottori M. Newton J.-B. Trahan
L.E. Smith, Q.C.	ATCO Utilities	

V. Regnault	Gaz Métro Limited Partnership
P.M. Keys	TransCanada PipeLines Limited
L.E. Smith, Q.C.	Union Gas Limited
E. Sweet	Ministry of Energy, Province of Ontario
M.A. Fowke	National Energy Board
M.A. Yuzda	National Energy Board

Chapter 1

Introduction

1.1 Background

Trans Québec & Maritimes Pipeline (TQM) operates natural gas transportation facilities as *mandatary*[1] of TQM Pipeline and Company, Limited Partnership, of which Gaz Métro Limited Partnership (Gaz Métro) and TransCanada PipeLines Limited (TransCanada) are the general partners.

The TQM facilities are located in the Province of Quebec and extend from a point of interconnection with the TransCanada Mainline system at Saint-Lazare to a point near Quebec City in the Municipality of Lévis on the south shore of the St. Lawrence River, and from Terrebonne, north of Montréal, to East Hereford on the border of the Province of Quebec with the state of New Hampshire, where it interconnects with the Portland Natural Gas Transmission System (PNGTS). See Figure 1-1 for a map of the system.

Prior to 1995, the National Energy Board (Board or NEB) generally approved pipeline tolls on an annual cost of service methodology for a forward test year basis. A pipeline company's cost of capital would typically be examined as part of a cost of service tolls application.

In the fall of 1994, the Board held the Multi-Pipeline Cost of Capital Proceeding (RH-2-94). In the RH-2-94 Decision[2] the Board approved a rate of return on common equity (ROE) for a low-risk, high-grade benchmark pipeline, based primarily on the equity risk premium test. The ROE for the benchmark pipeline was set at 12.25 per cent for the 1995 Test Year. The Board also adopted a formula for adjusting the ROE on an annual basis (RH-2-94 Formula).

The RHW-1-94 Decision[3] on the TQM Toll Application for 1995 and the RH-2-94 Decision, established TQM's final tolls for 1995. Similarly, the RHW-1-96 Decision[4] on the TQM Toll Application for 1996 and the RH-2-94 Decision resulted in TQM's final tolls for 1996.

In RHW-1-97, [5] the Board approved the "1997 and Multi-Year Tolls Agreement" as submitted by TQM and directed that the provisions of the Multi-Year Tolls Agreement be used to determine TQM's net revenue requirement and resulting tolls for 1997. TQM's Multi-Year Tolls

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1 Roughly equivalent to "power of attorney". The person who grants the mandate is called the mandatar, and the person who accepts the mandate is called the mandatary. A mandate is a contract by which one person designates another person to represent him or her, in other words act on his or her behalf, in legal dealings with a third party. See http://www.justice.gouv.qc.ca/english/publications/generale/procurat-a.htm#definitions

2 National Energy Board, RH-2-94 Reasons for Decision, TransCanada PipeLines Limited et. al. Cost of Capital, March 1995 [hereinafter RH-2-94].

3 National Energy Board, RHW-1-94 Reasons for Decision, Trans Québec & Maritimes Pipeline Inc., Tolls, April 1995.

4 National Energy Board, RHW-1-96 Reasons for Decision, Trans Québec & Maritimes Pipeline Inc., Tolls, May 1996.

5 National Energy Board, RHW-1-97 Reasons for Decision, Trans Québec & Maritimes Pipeline Inc. 1997 Tolls and Multi-Year Tolls Agreement, April 1997.

Agreement covered a five-year period, from 1 January 1997 to 31 December 2001. In 2001, the Board approved a five-year extension (to 31 December 2006) of TQM's Multi-Year Tolls Agreement. Under these settlements, the ROE was governed by the RH-2-94 Formula.

In 2007, TQM operated under interim tolls which were established at the 2006 toll level. Effective 1 January 2008, TQM is operating under revised interim tolls, which were established based on the terms of a Partial Settlement for the years 2007 to 2009 and approved by the Board by Order TGI-04-2007 dated 20 December 2007.

By letter dated 19 November 2007, TQM submitted an application requesting approval of a three-year Partial Settlement that represented an agreement with interested parties on all revenue requirement matters for the period of 1 January 2007 to 31 December 2009, with the exception of the cost of capital. The Partial Settlement Application formed part of a three step filing process that TQM established for determining tolls on its system. The steps were:

- Partial Settlement Application that did not include the cost of capital;
- 2008 Interim Toll Application; and
- Application for Cost of Capital for 2007 and 2008.

TQM indicated that it would apply for final 2007 and 2008 tolls following the disposition of the Partial Settlement and the two-year Cost of Capital Application. The Board approved the Partial Settlement Application on 4 September 2008. The Cost of Capital for 2009 is to be resolved by negotiation between TQM and parties or, failing that, will be litigated before the Board.

1.2 The Application

On 17 December 2007, TQM applied to the NEB for approval of the Cost of Capital that would be utilized by TQM in the calculation of final tolls to be charged by TQM for or in respect of transportation services provided to customers between 1 January 2007 and 31 December 2008. Pursuant to subsection 21(1) of the *National Energy Board Act* (Act), TQM applied for a review and variance of:

- the RH-2-94 Decision;
- NEB Order TG/TO-1-95 dated March 16, 1995;[6]
- NEB approval dated 23 November 2006 of a ROE of 8.46 per cent for the year 2007; and
- NEB approval dated 29 November 2007 of a ROE of 8.71 per cent for the year 2008.

Effectively, the review and variance application was to allow for the determination of an overall fair return on capital for TQM for the years 2007 and 2008.

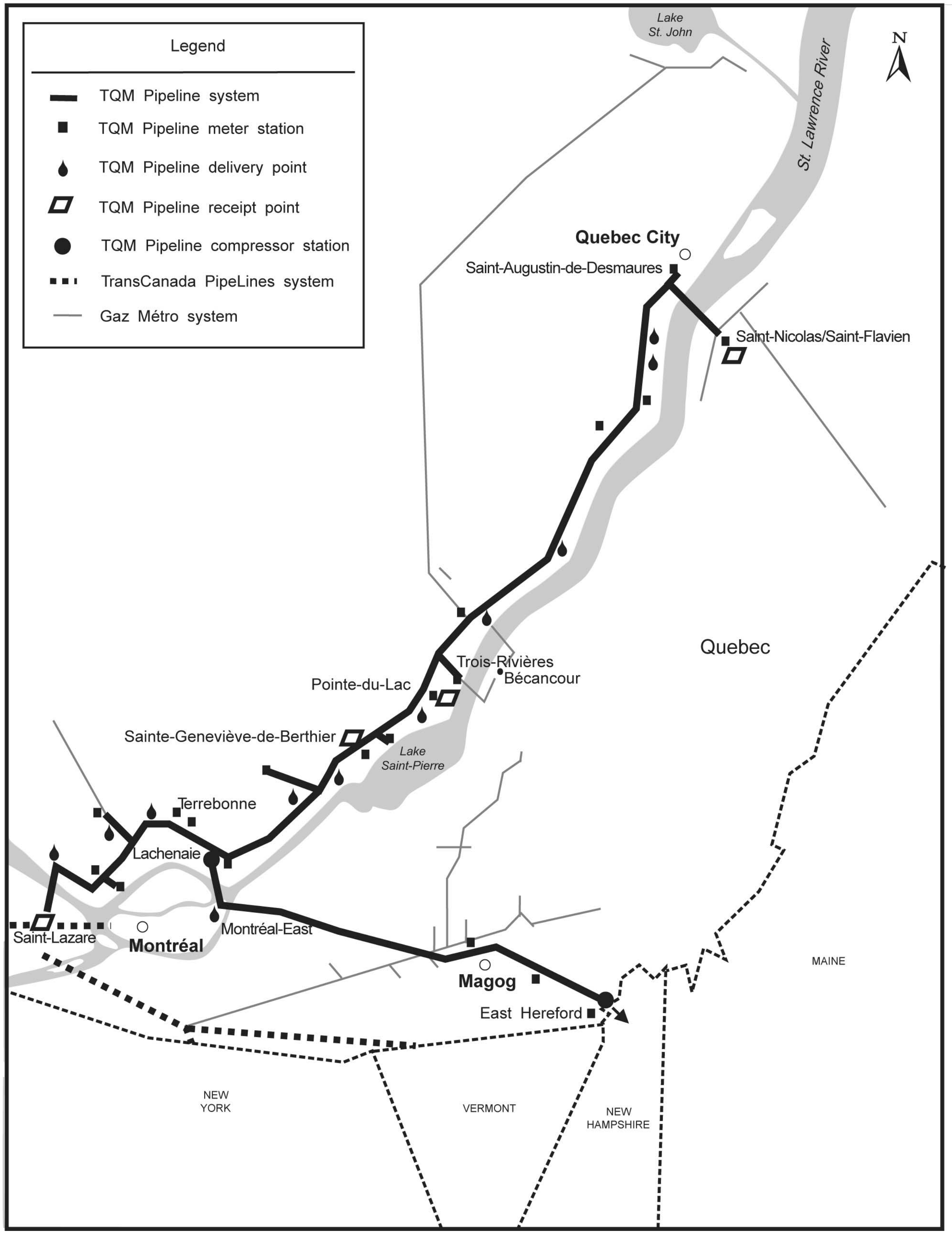
Pursuant to Part IV of the Act, TQM also applied for an order approving an overall fair return on capital for the years 2007 and 2008 resulting from the application of a rate of return of 11.0 per cent to a deemed equity component of 40 per cent of the TQM capital structure, together with the

6 From RH-2-94 Decision, *supra*, footnote 2, p. 35.

actual cost of debt of TQM. TQM stated that the requested overall return is equivalent to an After-Tax Weighted-Average Cost of Capital (ATWACC) of about 6.7 per cent (adjusted for the difference between the market cost of debt and the actual cost of TQM debt).

The Board issued Hearing Order RH-1-2008 on 22 January 2008 and scheduled an oral public hearing to begin on 23 September 2008 in Montréal, Quebec. The hearing commenced on 23 September 2008 and adjourned on 8 October 2008 in Montréal. The hearing reconvened in Calgary on 20 October 2008 and was completed on 22 October 2008. The hearing lasted 15 days.

Figure 1-1
TQM System Map



Chapter 2

Fair Return Standard

In the course of the hearing parties presented their views on the Fair Return Standard and the case law regarding it.[7] These cases, which underpin the Board's reasoning regarding the Fair Return Standard, and the Board's views on them, were discussed in the Board's RH-2-2004, Phase II Decision.[8] No party indicated that the reasoning in that Decision needed to be re-examined; indeed, TQM indicated that the determination of the return on equity of TQM for 2007 and 2008 should be guided by the principles that, in its view, were articulated in the RH-2-2004, Phase II Decision.

According to TQM, the following four principles are found in that Decision.

- The overall return on capital must meet the comparable investment, financial integrity and capital attraction requirements of the Fair Return Standard.
- Each element that goes into the determination of the overall return must be found by the Board to be reasonable. The Board then uses its judgment to ensure that a resulting return is a fair return in accordance with the legal requirements.
- Under the traditional methodology the fair total equity return is established by application of the rate of return on equity to the deemed equity component of the pipeline capital structure that reflects the business risk of a pipeline.
- The fair return is a cost to be determined without regard to the impact on tolls to be paid by customers.

The Canadian Association of Petroleum Producers (CAPP) in final argument submitted that when determining the fair return, there is a balance to be struck. It referred to the Board's RH-4-2001 TransCanada Decision which stated that a fair or reasonable rate of return should, in addition to meeting the comparable investment, financial integrity and capital attraction requirements, "achieve fairness both from the viewpoint of the customers and from the viewpoint of present and prospective investors".[9] In support of this submission, CAPP argued that the Federal Court of Appeal in *TransCanada v. NEB* looked at the 2001 Decision and the review of that decision[10] and stated that both decisions were correct.

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7 *Northwestern Utilities Limited v. City of Edmonton*, [1929] S.C.R. 186; *TransCanada PipeLines Limited v. National Energy Board et al.* [2004] F.C.A. 149 [hereinafter TransCanada v. NEB]; *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia et. al.* 262 U.S. 679 (1923) [hereinafter *Bluefield*]; *Federal Power Commission v. Hope Natural Gas* 320 U.S. 591 (1944) [hereinafter Hope].

8 National Energy Board, RH-2-2004, Phase II Reasons for Decision, TransCanada PipeLines Limited Cost of Capital, April 2005.

9 National Energy Board, RH-4-2001Reasons for Decision, TransCanada PipeLines Limited Cost of Capital, June 2002, at p. 11.

10 National Energy Board, RH-R-1-2002 Reasons for Decision, TransCanada PipeLines Limited Review of RH-4-2001 Cost of Capital Decision, February 2003.

CAPP argued that the U.S. cases cited by TQM and discussed by the Board in previous decisions also make it clear that there is a balance to be struck when a tribunal is exercising its judgment to determine the fair return. CAPP referred to the *Hope* decision, as cited in the Board's RH-2-2004, Phase II Decision, for the proposition that there is a "balancing of the investor and consumer interests."[11] Further, CAPP submitted that the *Bluefield* decision states that the utility is entitled to charge rates that are compensatory "but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."[12]

Views of the Board

The Board has considered the arguments put forward by TQM and CAPP and continues to believe that the legal framework for determining a fair return is as set out in Chapter 2 of the RH-2-2004, Phase II Decision. The Board notes that these views were based on the Federal Court of Appeal Decision in *TransCanada v. NEB*.

When using the cost of service approach to determine tolls, the cost of capital is determined using the Board's sound judgment. Often the largest and therefore most important portion of cost of capital is the overall return on equity. While customers and consumers have an interest in ensuring that the cost of equity is not overstated, in the Board's view, this is factored in by having intervenors test and challenge the position the company has put forward. It does not mean that in determining the cost of capital that investor and consumer interests are balanced. In the Board's view, the Federal Court of Appeal was clear that the overall return on equity must be determined solely on the basis of a company's cost of equity capital, and that the impact of any resulting toll increase is an irrelevant consideration in that determination.[13]

Therefore, the Board reaffirms the Fair Return Standard as articulated on page 17 of the RH-2-2004, Phase II Decision. The Fair Return Standard requires that a fair or reasonable overall return on capital should:

- be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
- enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and

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11 *Hope*, *supra,* footnote 7, at p. 603.

12 *Bluefield*, *supra,* footnote 7, at pp. 692-693.

13 While it is true that TransCanada's appeal in the *TransCanada v. NEB* case was denied, this is only because, after examining the facts, the Court found that the Board did not improperly consider the impact on consumers of increasing tolls when determining the cost of capital. (See paragraphs 37 and 42.)

- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement).[14]

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14 In previous decisions the Board used the word "standard" for each of the elements of the Fair Return Standard. The Board has changed the description to "requirement" to clarify that there are three requirements which should be met under the Fair Return Standard.

Chapter 3

Application for Review and Variance of RH-2-94

3.1 The Board's Review Procedure

Section 21 of the Act provides:

> (1) Subject to subsection (2), the Board may review, vary or rescind any decision or order made by it or rehear any application before deciding it.

The *National Energy Board Rules of Practice and Procedure, 1995* set out the requirements for a review application in section 44:

> (2) An application for review or rehearing shall contain...
>
> (b) the grounds that the Applicant considers sufficient, in the case of an application for review, to raise a doubt as to the correctness of the decision or order ... including
>
> (ii) changed circumstances or new facts that have arisen since the close of the original proceeding…

There is no automatic right of review of a Board decision. A decision to review is discretionary.

Normally, a review entails a two-step process: first, it must be determined whether a doubt has been raised as to the correctness of the impugned decision or order, and then, if that test has been met, the review is considered on its merits. These stages are commonly referred to as phases I and II and are analogous to seeking leave to appeal from a court, and subsequently having the appeal heard. In this case, the Board did not explicitly delineate the two phases of the review process, but considered both phases when deliberating on the evidence in this hearing.

This is the first time that the RH-2-94 Formula has been reviewed since *TransCanada v. NEB*. In that case, the Court confirmed that the Board's review procedure is the proper process for considering the RH-2-94 Formula and that as a result the burden of proving that the RH-2-94 Formula no longer applies rests with the Applicant which, in this case, is TQM.

As Justice Rothstein set out:

> In its 1995 decision, the Board stated that its automatic adjustment formula was to reflect a simplified procedure to determine annual adjustments to pipeline rates of return on common equity. It was therefore to continue indefinitely. When an affected party wishes to change the process, it has the onus to demonstrate that its

> proposal is preferable to the one which is the subject of a binding Board order. That is not an improper onus.[15]

It is with Justice Rothstein's words in mind that the Board considers TQM's request for a review of the RH-2-94 Decision as it applies to TQM for 2007 and 2008.

3.2 Context

3.2.1 Use of the RH-2-94 Formula

The Board held the RH-2-94 proceeding to put in place a means of improving the efficacy of the toll setting process for the year 1995 and beyond. In March 1995, the RH-2-94 Decision set the rate of return on common equity (ROE) for a benchmark pipeline at 12.25 per cent for 1995. In this context, a benchmark pipeline referred to a hypothetical utility whose overall investment risks are characteristic of a low-risk, high-grade regulated pipeline. The Board used this benchmark pipeline as the standard for determining the allowed ROE for the pipelines subject to the RH-2-94 proceeding. Under this methodology, company-specific business risk was to be accounted for in the equity component of the deemed capital structure of NEB-regulated pipelines. The Board approved a 30 per cent equity thickness for all gas pipelines subject to the RH-2-94 Decision, except for Westcoast Energy Inc. (Westcoast).

In addition, the RH-2-94 Decision established a mechanism to adjust the allowed ROE annually (RH-2-94 Formula). The RH-2-94 Formula directly links the ROE to a forecast of a long-term Government of Canada bond yield and adjusts the ROE for 75 per cent of the change in the forecasted yield. The forecast of a long-term Government of Canada bond yield is determined by averaging the 3-month-out and 12-month-out forecasts of 10-year Government of Canada bonds as published by *Consensus Forecasts* in November of each year. To this average is added the average spread between 10-year and 30-year Government of Canada bond yields as published daily in *The Financial Post* throughout the month of October of that year.

The Board did not find it necessary to specify a bond yield range outside of which the RH-2-94 Formula would not operate. Also, the Board did not set a time limit on the life of the RH-2-94 Formula. The Board indicated that its objective was to conduct detailed examinations of the pipelines' cost of capital only when significant changes had occurred in financial markets, business circumstances, or in general economic conditions. Furthermore, the Board was prepared to consider a reassessment of capital structures, likely on a pipeline-by-pipeline basis, in the event of a significant change in business risk, in corporate structure or in corporate financial fundamentals.

TQM was subject to the RH-2-94 Decision from 1995 until the end of 2006 and operated under a Multi-Year Tolls Agreement reached between TQM and interested parties between 1997 and 2006. As a result, the last time TQM's cost of capital and business risk were assessed by the Board was during the RH-2-94 proceeding.

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15 *Supra*, footnote 7, at paragraph 56.

3.2.2 Changes in Business Circumstances, Financial Markets and General Economic Conditions

Submissions of TQM

TQM submitted that new facts and changed circumstances since the RH-2-94 proceeding raise a doubt as to the correctness of the RH-2-94 Decision as it relates to TQM for 2007 and 2008. As well, TQM stated that all changes affecting the cost of capital, other than those taken into account by the mechanical relationship between the RH-2-94 Formula and the Government of Canada bond yields, have not been accounted for by the RH-2-94 Formula.

Changes in Business Circumstances

TQM was of the view that the market environment in which gas pipelines in North America operate has changed significantly since 1994 reflecting greater uncertainty in the supply of gas, greater uncertainty in the extent and timing of growth in demand and greater competition among pipelines for customers seeking transportation service. According to TQM, there has been no quantitative link between the amount that the deemed equity thickness has been increased by the Board, or in settlements relying on the RH-2-94 Formula, and the increase in the total return required by investors to compensate them for bearing that increased risk.

Changes in Financial Markets

Major events such as increased geopolitical instability, extensive corporate corruption and collapse of the technology, media and telecom sectors were cited by TQM as having impacted financial markets and having raised the risk premium for equities since 1994. Also, the ratio of Canadian government debt to Gross Domestic Product (GDP) saw a decline, which put a material downward pressure on bond yields. Furthermore, the world's capital markets, including Canadian financial markets, have become increasingly integrated resulting in capital easily flowing from one market to another in pursuit of the best investment opportunities and competitive returns. TQM submitted that this integration has lead to increased competition for capital for Canadian companies, including TQM.

Changes in Canada's General Economic Conditions

TQM expressed the view that Canada has undergone significant changes in general economic conditions since 1994. These changes were most evident in the rise and fall in interest rates, a drop in Government of Canada bond yields, and an appreciation and subsequent fall in the Canadian/US dollar exchange rate. Commodity markets (crude oil, natural gas and base metals) also showed material increases in prices and volatility.

Based on the above-mentioned changes in business circumstances, financial markets and general economic conditions, TQM was of the view that a review of the RH-2-94 Formula as it applies to TQM for 2007 and 2008 was warranted.

Submissions of Intervenors

Changes in Business Circumstances

Dr. Booth, an expert witness for CAPP and the Industrial Gas Users Association (IGUA), stated that at the time of the RH-2-94 Decision, the Board used the same 30 per cent common equity ratio for all the major natural gas pipelines. As a result, Dr. Booth was of the view that, while it might seem obvious that the TransCanada Mainline was the benchmark, in substance all major natural gas pipelines were. In Dr. Booth's opinion, the two major developments since 1994 have been the increased supply of natural gas outside of the Western Canada Sedimentary Basin (WCSB) and the increase in intra-Alberta demand. Both have resulted in lower throughput on the TransCanada Mainline. According to Dr. Booth, neither of these factors affect TQM to the same degree as the WCSB export pipelines. Dr. Booth was of the view that the development of the Dawn Hub provides TQM with much more flexibility than any of the WCSB export pipelines. Dr. Booth argued that a case could be made that TQM is the new low risk benchmark pipeline.

Changes in Financial Markets and Canada's General Economic Conditions

In comparing the capital market conditions between 1994, 2001 and 2008, Dr. Booth assessed the variables contained in the following table.

Table 3-1
Capital Market Conditions: 1994, 2001 and 2008

	1994	2001	2008
Long-term Canada bond yield forecast			
Consensus Forecast	8.35%	5.95%	4.61%
Dr. Booth (and Dr. Berkowitz*)	8.25%	6.00%	4.75%
Real Canada yield	4.62%	3.60%	1.65%
Market risk premium	3.5% - 4.0%	4.50%	5.00%
Beta estimates	0.45 – 0.55	0.42 – 0.60	0.45 – 0.55
Equity risk premium for pipeline	250 bps	250 bps	300 bps

* Dr. Berkowitz testified in the RH-2-94 and RH-4-2001 proceedings.

According to Dr. Booth, when comparing the three periods, the major changes occurred between 1994 and 2001. In 2001, Dr. Booth pointed out that after having carefully considered all of the evidence relating to rate of return on common equity, the Board maintained the RH-2-94 Formula since it continued to yield returns appropriate for the TransCanada Mainline. Furthermore, Dr. Booth was of the view that the change in financial market conditions is less since 2001 than what occurred between 1994 and 2001. Therefore, Dr. Booth saw no substantial change in market conditions that would warrant a change in the RH-2-94 Formula and supported its continued use.

3.3 Suggested Approaches

3.3.1 After-Tax Weighted-Average Cost of Capital

Submissions of TQM

TQM approached the analysis of the fair return in two different ways. The first way was the utilization of the ATWACC approach to cost of capital estimation. The second way was the traditional methodology that reflects business risk in the equity component of the capital structure and a separate estimate of the rate of return on equity. TQM stated that ATWACC and the traditional methodology, when properly applied, yield similar results in terms of overall return on capital. TQM submitted that the ATWACC approach is the one used by corporations in the analysis of investment opportunities.

According to TQM, the base criteria to compare investment opportunities for the company are the calculations of net present value (NPV) and internal rate of return (IRR). In this context, the ATWACC is the discount rate used to determine the NPV of an investment and the IRR is the calculated return over the life of an investment. If the NPV is positive, the investment opportunity adds value and if the IRR is above the ATWACC (which can be considered the hurdle rate), the investment opportunity will have a positive NPV and therefore will add value.

The ATWACC approach can be considered from two different perspectives. The first one is an "authorized ATWACC" where the capital structure and ROE used in the analysis are the ones authorized by a regulator. The second perspective is a "market-based ATWACC" where the capital structure, cost of equity and cost of debt are all based on market values or market costs.

It was the opinion of one of TQM's expert witnesses, Dr. Kolbe, that ATWACC is the most fundamental measure of the rate of return required for a given level of business risk. ATWACC was used as the starting point for his analyses. Dr. Kolbe submitted that a stock's risk depends in part on the amount of debt a company has in its capital structure since the presence of debt magnifies the risk equity holders bear. As a result, the extra risk for equity created by debt's magnification is known as financial risk. Therefore, Dr. Kolbe was of the view that when estimating the cost of equity from sample companies, differences in the level of financial risk between the sample companies and a particular regulated company must be considered and controlled for.

TQM stated that it is not advisable to assume an appropriate capital structure for a specific company when comparing returns on equity because a capital structure is specific to each company and an external observer cannot judge whether this structure is appropriate or not. As a result, TQM argued that the best way to compare investment returns of different businesses is the ATWACC approach which focuses on the total return on capital and adjusts for financial risk.

Submissions of Intervenors

Dr. Booth referred to the ATWACC approach as leverage adjustments and was of the view that this approach was an erroneous and irrelevant way of looking at the problem of different levels of risk between TQM and sample companies when determining a fair return. Dr. Booth submitted that the ATWACC approach is not needed by any financial theory. He expressed the view that the reliance on an ATWACC approach, or leverage adjustments, to determine the return on capital for TQM for 2007 and 2008 was not necessary because the actions of regulators have equalized the risks between large classes of different types of utilities. In the event where there would be a difference in risk to the common shareholders between TQM and the sample firms, Dr. Booth argued that it would be possible to make an adjustment directly to the allowed return on equity without using an ATWACC approach. CAPP argued that an ATWACC approach does not avoid capital structure decisions since this approach requires the estimation of capital structure of sample companies.

Dr. Safir, a CAPP expert witness, submitted that the ATWACC approach is not as transparent as the traditional approach when determining a fair return, and that transparency was a valuable tool for a regulator. Dr. Booth argued that this lack of transparency created estimates for TQM for 2007 and 2008 that are beyond the range of reasonableness when compared to what other regulators have awarded to other Canadian utilities.

The Ministry of Energy of the Province of Ontario (Ontario) argued that there is no need to adopt ATWACC and that TQM's proposal in that regard should be dismissed. Ontario added that there are issues with ATWACC such as sample sizes, betas and relative risk of the Canadian sample, as well as the fact that ATWACC has not been adopted by other North American regulatory bodies.

3.3.2 RH-2-94 Formula and Similar Approaches

Submissions of TQM

According to TQM, the Board should grant the variance from the RH-2-94 Decision for the purpose of determining TQM's cost of capital for 2007 and 2008.

In addition to the changes in business circumstances, financial markets and general economic conditions discussed in Section 3.2 that were cited by TQM as reasons to review the RH-2-94 Decision, TQM submitted the results of Dr. Vander Weide's four tests regarding the validity of the RH-2-94 Formula. Dr. Vander Weide concluded the following.

- The RH-2-94 Formula currently understates the required equity risk premium in Canadian utility stocks by at least 200 basis points.
- The cost of equity for utilities declines by less than 50 basis points when interest rates decline by 100 basis points, rather than the 75 basis point decline as stipulated by the RH-2-94 Formula.
- The volatility and the realized return of Canadian utility stock indices have exceeded that of the market as a whole, implying that the RH-2-94 Formula understates the current cost of equity of Canadian utilities.
- The current forward-looking required equity risk premium on U.S. utility stocks is 150 basis points more than the 4.12 per cent offered by the RH-2-94 Formula.

Mr. Engen, one of TQM's expert witnesses, stated that sell-side analysts and credit rating agencies have displayed concern over the low ROEs produced by the RH-2-94 Formula but, on the other hand, analysts have supported the transparency of a formula such as the RH-2-94 Formula since this approach provides clarity and the resulting returns can be fully anticipated.

TQM also submitted that, absent strategic or franchise considerations, no pipeline company is investing new capital in new long-term projects at the returns currently allowed by the RH-2-94 Formula. As a result, embedded capital of existing Canadian pipelines receives significantly discounted returns relative to that of newly built projects. It was noted by TQM that negotiated settlements are consistently hundreds of basis points over the RH-2-94 Formula ROE.

Furthermore, TQM was of the view that financial risk (leverage) is important to consider and that comparing returns on equity without considering the financial risk affecting these returns is not sufficient. TQM suggested that the ATWACC approach, by determining the proper total return on the investment irrespective of financing, explicitly provides control for financial risk, as opposed to the RH-2-94 Formula or an approach by component relying on a stand alone cost of equity estimate. Finally, TQM noted that there is no empirical way to determine an equity thickness based on the business risk of a company.

Submissions of Intervenors

The Canadian Gas Association (CGA) expressed the view that the total returns based on the RH-2-94 Formula are no longer comparable to those returns enjoyed by investments of similar risk to Canadian utilities and do not meet the Fair Return Standard. The CGA submitted that annual adjustment factors, if any, should track not just factors such as interest rates, but also the returns enjoyed by other investments of similar risk. It was argued by the CGA that embedded capital trapped in an existing system should not earn inferior returns to discretionary capital committed to new services or expansions.

Spectra Energy Transmission (Spectra)[16] and Union Gas Ltd. (Union) argued that the current return on equity from the RH-2-94 Formula fails to meet the Fair Return Standard in terms of a total return which would be needed to be truly comparable to other investments available of similar risk. According to Union and Spectra, the cost of capital is determined by the interplay of many dynamic factors which are simply beyond the capacity of a single financial model to predict and which the RH-2-94 Formula cannot capture by itself.

In CAPP's view, the application to review the RH-2-94 Formula should be dismissed. CAPP supported the continued use of the RH-2-94 Formula and was of the view that the current allowed ROE is in fact generous. In addition, according to CAPP, the RH-2-94 Formula was and continues to be successful in reducing the amount of repetitive testimony in regulatory proceedings. CAPP submitted that the predictability, the stability and the understanding of the RH-2-94 Formula were all valued attributes of this approach. Dr. Booth presented the view that the Board cannot manage capital market risk for the pipelines under its jurisdiction and the Board has correctly used basic principles of finance to offset the business risk of these pipelines by allowing changes in their financial risk. By equalizing overall risk (combined business risk,

16 Carrying on business of Westcoast Energy Inc. (Westcoast).

financial risk and investment risk), the Board can then allow the same return on equity for different types of utilities relying on the RH-2-94 Formula.

CAPP stated that even if the RH-2-94 Formula operates mechanically, there is nothing mechanical in the way the RH-2-94 Formula was adopted in 1995 and reviewed in 2001 and 2004. To support this, it noted that since 1994, substantial investments have been made and continue to be made by pipelines and utilities subject to returns set by various formulae in different jurisdictions. Notwithstanding warnings of applicant witnesses in hearings, CAPP was of the view that debt and equity have flowed, and are continuing to flow, to investments subject to formula returns. Furthermore, CAPP argued that if the problem were so great and had gone on for so many years, then there would be clear and objectively observable market evidence of a problem of capital attraction and capital retention. CAPP stated that it saw no such evidence.

The view was expressed by Dr. Booth that the RH-2-94 Formula has generally resulted in a downward movement of the fair ROE as lower long Canada bond yields have caused a reduction in the risk premium in the long Canada bond yield with a corresponding increase in the market risk premium. As a result, Dr. Booth submitted that the 75 per cent adjustment mechanism to the RH-2-94 Formula has been remarkably accurate. He therefore judged the RH-2-94 Formula to be successful and recommended that it continue to be used with some minor downward adjustment in the level of ROE.

Dr. Booth submitted that he has consistently recommended that business risk be assessed in annual tolls hearings, where other firm specific information is heard and the appropriate capital structure or premium to the generic ROE is set. The generic ROE formulae, such as the RH-2-94 Formula, can then be assessed relatively infrequently based on changes in capital market conditions.

Regarding Dr. Vander Weide's results on the validity of the RH-2-94 Formula, CAPP argued that they do not form a sound basis for a determination of the cost of capital since evidence from low risk companies was ignored, adjusted betas were used in the estimates, and some of those discounted cash flow (DCF) estimates relied on analysts' growth forecasts which are known to be biased. CAPP also argued against the reliance on U.S. firms since they are more risky than TQM.

CAPP submitted that, if the RH-2-94 Formula were open to review, it would recommend a 7.75 per cent ROE for TQM for 2007 and 2008 and that the RH-2-94 Formula be rebased accordingly, based on Dr. Booth's ROE recommendation.

IGUA argued that the Board should not depart from the RH-2-94 Formula since it remains appropriate and has stood the test of time. According to IGUA, the RH-2-94 Formula generates results at the high end of the range of possible appropriate ROEs relative to the very nominal risks TQM bears.

Ontario argued that the RH-2-94 Formula should be retained since it is transparent, provides clarity and remains valid.

Views of the Board

Review and Variance of the RH-2-94 Decision

In considering an application for review and variance pursuant to subsection 21(1) of the Act, the Board takes into account the facts that could potentially raise a doubt as to the correctness of the original decision. Typically, the Board will look at changed circumstances or new facts that have arisen since the close of the original proceeding, or facts that were not placed in evidence in the original proceeding and that were then not discoverable by reasonable diligence. Furthermore, the Board stated in the RH-2-94 Decision that its objective in initiating the RH-2-94 proceeding was to conduct detailed examinations of a pipeline's cost of capital only when significant changes had occurred in financial markets, business circumstances, or in general economic conditions.[17] The Board also stated that it would be prepared to consider a reassessment of capital structures in the event of a significant change in business risk, in corporate structure or in corporate financial fundamentals.[18] The Board did not set a limit on the life of the RH-2-94 Formula and did not expect to reassess the rate of return on common equity in a formal hearing for at least three years from the time of the RH-2-94 Decision.

With regard to the variance application, the Board notes that TQM has been subject to the RH-2-94 Decision and the associated adjustment mechanism for 12 consecutive years (1995 to 2006, inclusive). The Board notes that the RH-4-2001 proceeding was the last time when the RH-2-94 Formula was challenged. The RH-4-2001 proceeding was specific to TransCanada, just as the RH-1-2008 proceeding is specific to TQM. As a result, the Board finds that it should assess the changes since 1994 instead of 2001 in this proceeding. In the Board's view, the 14-year period since 1994 is a significant time period in the context of financial regulation.

Also, the Board is of the view that there have been significant changes since 1994 in the financial markets as well as in general economic conditions. More specifically, Canadian financial markets have experienced greater globalization, the decline in the ratio of government debt to GDP has put downward pressure on Government of Canada bond yields, and the Canada/US exchange rate has appreciated and subsequently fallen. In the Board's view, one of the most significant changes since 1994 is the increased globalization of financial markets which translates into a higher level of competition for capital. When taken together, the Board is of the view that these changes cast doubt on some of the fundamentals underlying the RH-2-94 Formula as it relates to TQM.

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17 RH-2-94 Reasons for Decision, *supra*, footnote 2, at p. 2.

18 RH-2-94 Reasons for Decision, *supra*, footnote 2 at p. 32.

As explained in the RH-2-94 Decision, the initial return on equity determination was meant to be applied to a benchmark pipeline which was assumed to be a hypothetical utility whose overall investment risks are characteristic of a low-risk, high-grade regulated pipeline. The Board notes that the equity thickness of the benchmark pipeline was not explicitly specified in the RH-2-94 Decision. The Board approved a 30 per cent equity thickness for all gas pipelines subject to the Decision, except for Westcoast, which has been interpreted by some as implicitly assigning an equity thickness of 30 per cent for the benchmark pipeline. However, the role of the benchmark pipeline, its changing risk level and its specific equity thickness have not been considered explicitly, and that leaves a doubt as to the exact level of financial risk inherent in the return on equity as determined by the RH-2-94 Formula for the benchmark pipeline.

The RH-2-94 Formula relies on a single variable which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, the changes discussed above regarding the new business environment are examples of changes that, since 1994, may not have been captured by the RH-2-94 Formula. Over time, these omissions have the potential to grow and raise further doubt as to the applicability of the RH-2-94 Formula result for TQM for 2007 and 2008.

The Board notes that there were two distinct aspects of the RH-2-94 Decision, namely the adjustment mechanism which applied to all pipelines subject to the Decision and the determination of the capital structure on a pipeline-by-pipeline basis. On the one hand, the Board views the adjustment mechanism as fully transparent and predictable. The Board notes that this adjustment mechanism has received for some time the praises of the investment community citing that this approach provides clarity, transparency and its results can be fully anticipated. On the other hand, the capital structure decisions made on a pipeline-by-pipeline basis are less transparent. The Board's original objective was to adjust the capital structure, hence adjust financial risk, to offset changes in business risk experienced by any given pipeline subject to the RH-2-94 Decision. The Board is of the view that while estimating the equity ratio based on business risk, separately from the determination of the return on equity, can be useful in a regulatory context, it does not reflect the way that much of the business world approaches capital structure and capital budgeting decisions.

Based on the above reasons, the Board has decided to grant the variance from the RH-2-94 Decision to TQM for 2007 and 2008 as it relates to its cost of capital.

Approach Used to Determine TQM's Return on Capital for 2007 and 2008

Beyond the RH-2-94 Formula, two other approaches have been presented to determine TQM's cost of capital for 2007 and 2008. TQM and its expert witnesses presented the ATWACC approach – an aggregate approach to the estimation of cost of capital. CAPP and its expert witness presented a stand-alone cost of equity estimate – an approach by component to the estimation of cost of capital.

The Board is of the view that the ATWACC approach is more aligned with the way capital budgeting decision making takes place in the business world as compared to an approach by component that would include a stand-alone cost of equity estimate. When comparing investment opportunities, TransCanada and Gaz Métro, both owners of TQM, submitted that they rely on an ATWACC to determine a hurdle rate and to make capital budgeting decisions. In the Board's view, the use of an ATWACC approach alleviates the need to attempt to estimate a deemed capital structure based on business risk in the initial step of the process as is required in the context of the RH-2-94 Decision. The Board also notes that the ATWACC approach enables the comparisons of returns on an equal footing between companies of comparable risk since the ATWACC approach neutralizes financial risk differences when comparing investment opportunities. The Board is of the view that this approach facilitates the comparisons of returns by removing the impact of financial risk. Consequently, the ATWACC approach better utilizes financial market information.

Figure 3-1 illustrates how an aggregate approach, such as the ATWACC approach, may be used by the Board to determine TQM's total cost of capital for 2007 and 2008. This approach requires a business risk analysis that would be used to assess how the risks of TQM have evolved since they were last considered by the Board. The business risk analysis would also be relied upon to select firms of comparable risks based on the traditional five factors (supply, market, competitive, regulatory and operational risks). Once comparable firms are selected, information can be extracted from those firms, including cost of equity, capital structure and cost of debt to derive an aggregate cost of capital. At each step of this process, judgment is necessary to select the inputs that would ultimately inform the determination of the cost of capital for TQM for 2007 and 2008.

CAPP has presented an approach by component which relies on a stand-alone cost of equity estimate. CAPP has also suggested an equity thickness, based on its assessment of TQM's business risk, to which the ROE estimate would be applied.

Figure 3-2 illustrates an approach by component to the determination of a total cost of capital as endorsed in the RH-2-94 Decision. This approach requires two parallel decisions: an ROE determination and a capital structure determination. The ROE determination requires the selection of firms of comparable risks to TQM from which an ROE estimate could be derived. Parallel to this decision, a business risk assessment of TQM is made to determine a capital structure which would reflect its level of business risk. Once these determinations have been made separately, they are combined to derive the total equity return to which the embedded cost of debt is added, to produce the total return on capital.

The difficulty arises as to which of these two approaches is judged as the better tool to link the components impacting the determination of fair return. This, in the Board's opinion, is a matter of informed judgment. Having carefully considered both approaches, the Board finds that the ATWACC approach enables better comparisons of return on capital for companies of similar risk. This offers the potential to avoid separating two elements that are inevitably linked: capital structure and return on equity. Further, it is the Board's view that relying on an approach, such as ATWACC, that mirrors the business decision-making process contributes to its validity as an appropriate method for estimating the cost of capital. Accordingly, the Board will use the ATWACC approach to inform its judgment to determine TQM's cost of capital for 2007 and 2008.

In choosing to rely on an ATWAAC approach, transparency was an important factor considered by the Board in its decision. A single ATWACC number that incorporates the total return on capital on a comparable basis amongst companies assists the Board in making meaningful comparisons. This contrasts with simply looking at the return on equity which provides only a partial understanding of the total return on capital. Further, a capital structure is specific to each company and it is difficult for an external party to assess its appropriateness. The greater ease of comparison of using the ATWACC approach, in the Board's view, is less prone to error and enhances clarity.

The Board notes that an ATWACC approach can be implemented in various ways. The specific ATWACC methodology upon which the Board will rely in this proceeding will be described in Chapter 4 of these Reasons.

All of the evidence submitted by parties in this proceeding will be considered using an ATWACC approach to determine an appropriate aggregate return. The Board's determination on fair return will be made in Chapter 7 of these Reasons.

Figure 3-1
An Aggregate Approach to the Fair Return Standard using the ATWACC Approach

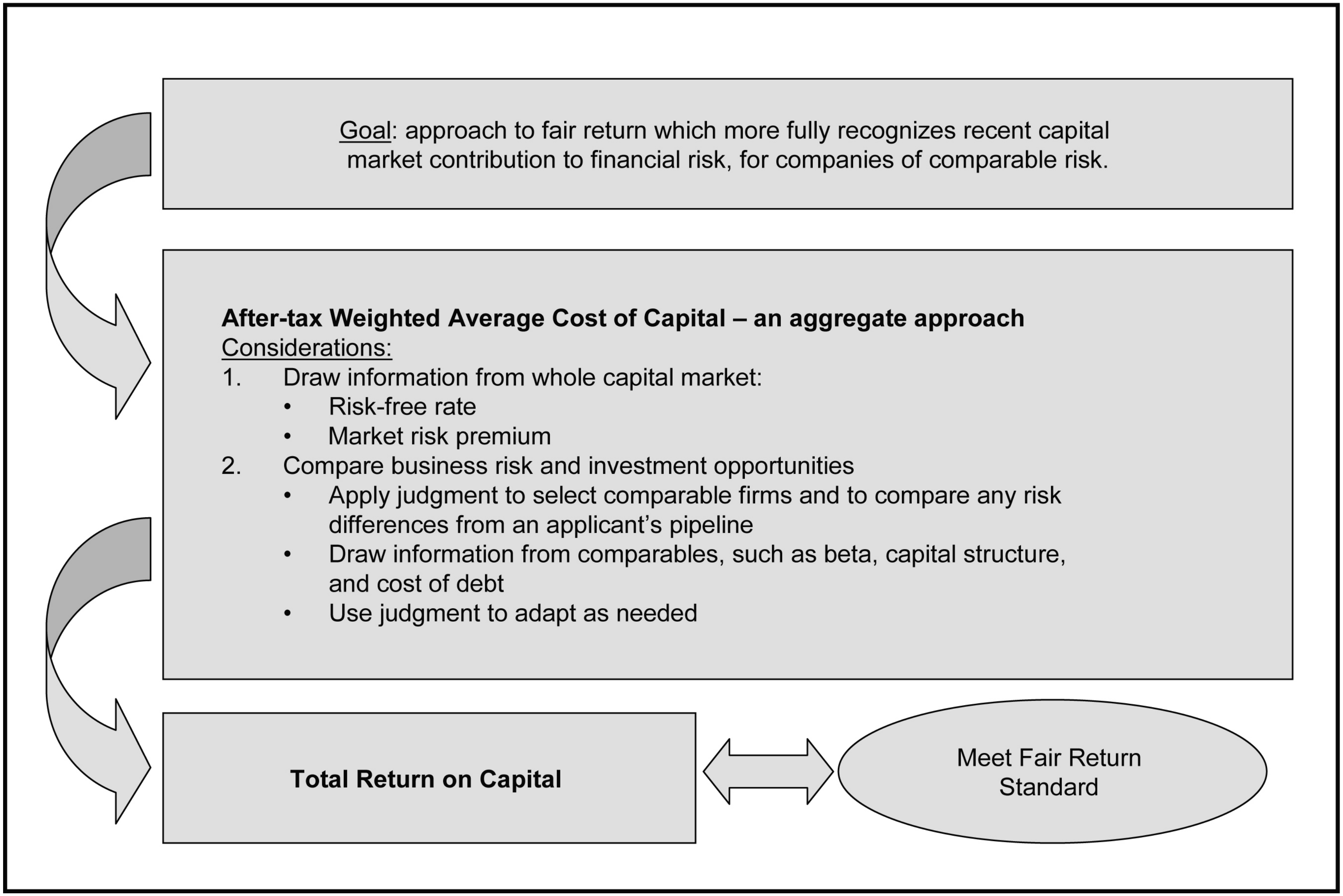
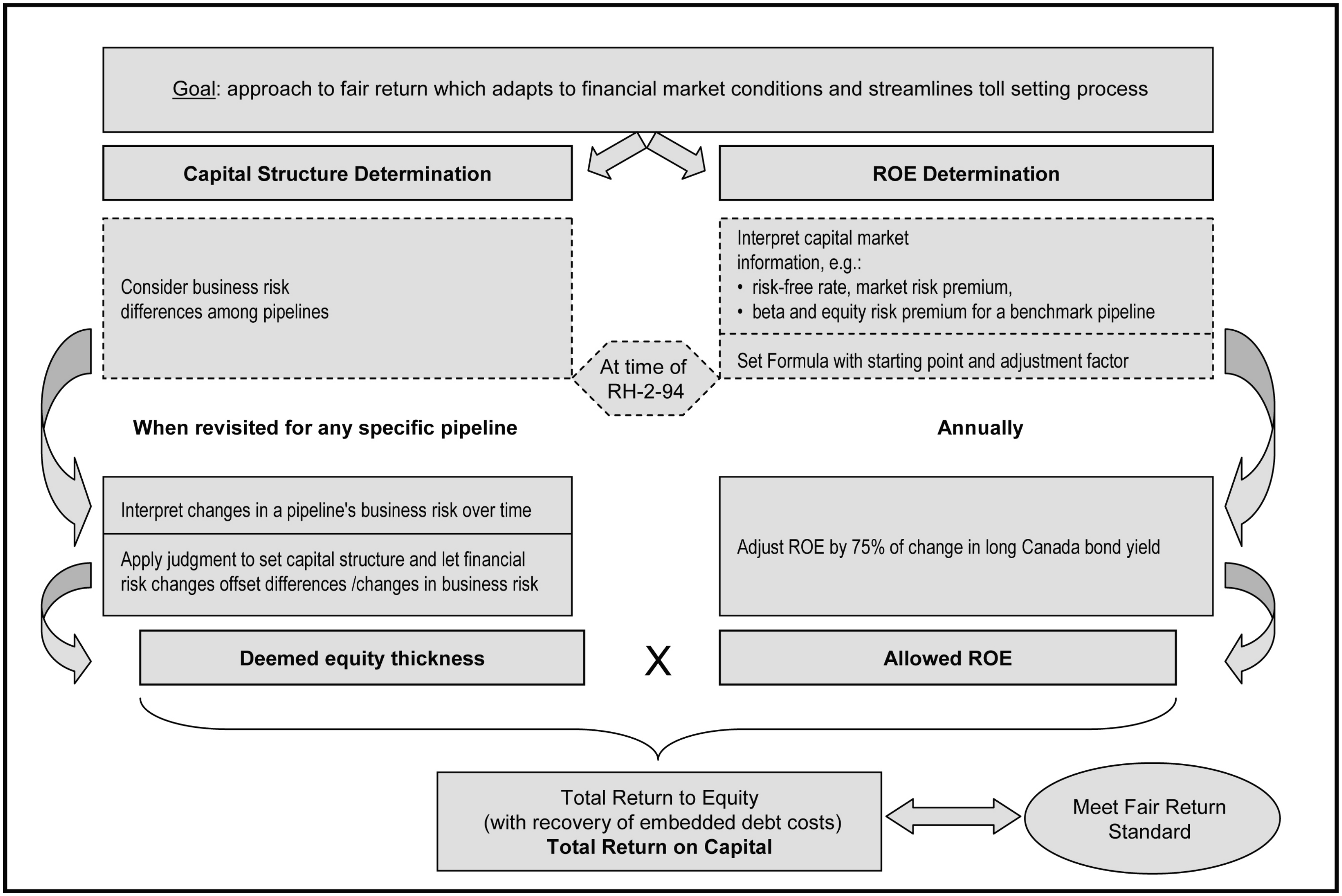


Figure 3-2

An Approach by Component to the Fair Return Standard using the RH-2-94 Formula



Chapter 4

Implementation of the ATWACC Methodology

In a regulatory context, the ATWACC approach relies on the comparison of total costs of capital of sample companies considered to be of similar risk to the regulated entity, which in this case is TQM. A specific ATWACC methodology is required to compute the ATWACC of each company in the sample and may involve many analytical steps. The resulting ATWACCs may be averaged to derive the total cost of capital of the sample. The resulting total cost of capital can then be applied to TQM with judgment on various adjustments to reflect differences in risk.

The ATWACC approach relies on the following equation to estimate the total cost of capital of a firm:

$$ATWACC^{19} = (r_e * w_e) + (CoD * w_d * (1\text{-}tx))$$

Where	$r_{e:}$	cost of equity
	CoD:	cost of debt
	w_e:	equity thickness in the capital structure
	w_d:	debt thickness in the capital structure
	tx:	corporate income tax rate[20]

In this chapter, the Board addresses each component of this equation and determines how it intends to use these parameters which, when combined together in an ATWACC methodology, will inform its judgment about TQM's cost of capital for 2007 and 2008.

4.1 Cost of Equity Methods

Submissions of TQM

Dr. Vilbert presented cost of equity estimates based on the capital asset pricing model (CAPM), the empirical capital asset pricing model (ECAPM) and the discounted cash flow model (DCF).

CAPM, as used by Dr. Vilbert, is represented by the following equation:

$$r_e = r_f + \beta * (MRP)$$

Where	r_f:	risk-free rate
	β:	beta factor
	MRP:	market risk premium

19 A potential and small contribution from preferred shares has been ignored for simplicity in this description, although it was addressed by the expert evidence submitted by Dr. Vilbert.

20 This is mathematically equivalent to pre-tax WACC of (CoD * w_d) + (r_e * w_e) + (allowance for income taxes payable on the equity portion).

Dr. Vilbert contended that CAPM has not generally performed well as an empirical model, but that its shortcomings are directly addressed by ECAPM. Specifically, Dr. Vilbert submitted that ECAPM recognizes the consistent empirical observation that CAPM underestimates (overestimates) the cost of capital for low (high) beta stocks. The alpha parameter (α) in ECAPM would adjust for this fact. When using the long-term risk-free rate, as is the case in his analysis, Dr. Vilbert suggested that α values of 1 and 2 per cent are appropriate. These α values are at the low end of the spectrum suggested by research on this topic because the use of a long-term risk-free rate incorporates some of the desired effect of using ECAPM.

Dr. Vilbert relied on the following ECAPM:

$$r_e = r_f + \alpha + \beta * (MRP - \alpha)$$

Where	r_f:	risk-free rate
	α:	alpha factor
	β:	beta factor
	MRP:	market risk premium

According to Dr. Vilbert, ECAPM estimates deserve the most weight because ECAPM adjusts for empirical shortcomings related to CAPM.

Dr. Kolbe indicated that shareholders of companies regulated on a book-value rate base receive compensation for inflation through an inflation premium in the rate of return rather than through appreciation of asset value as would the shareholders of non-regulated companies. Dr. Kolbe submitted that bondholders get inflation compensation in the same way, through an inflation premium in the interest rate. This similarity between bondholders and shareholders of companies regulated on a book-value rate base makes regulated company returns especially sensitive to fluctuations in the bond market.

TQM submitted that the measured betas of utilities regulated on a book-value rate base are underestimated since CAPM relies on a proxy for the market portfolio which consists entirely of common stocks. Dr. Kolbe recommended the use of adjusted betas to estimate the cost of equity for utilities regulated on a book-value rate base to correct for this estimation problem and commented that this is a directional adjustment only. Dr. Kolbe further stated that using adjusted betas is probably not enough, but it is an approach widely used. Dr. Vander Weide explained that the use of adjusted betas and ECAPM have the same type of effect as they compensate somewhat for the empirical observation that traditional CAPM tends to underestimate the cost of equity for companies with betas less than one.

The DCF model was relied upon by Dr. Vilbert as a check for his CAPM and ECAPM results. The DCF model was used by TQM's expert witnesses with company specific data and analysts' growth forecasts. Dr. Vander Weide contended that using composite data in the DCF model, as it was done by Dr. Booth, makes it impossible to match stock prices with the cash flows that are being valued at that price and that the data set might include companies for which the DCF model does not apply. To be consistent with the forward-looking nature of the DCF model, Dr. Vander Weide submitted that Dr. Booth should have estimated expected future growth using forecasted growth rates rather than the reported values for the last year since analysts' forecasts of future growth are superior to historically oriented growth measures in predicting a firm's stock price.

Dr. Kolbe mentioned that multi-factor models, as used by Dr. Booth, are notoriously unstable and none of these models have garnered support in the financial community. Also, Dr. Kolbe expressed the opinion that a two-factor model understates the relative risk of U.S. electric utilities and Canadian rate-regulated companies against the broader market used by CAPM theory if the betas are left unadjusted.

Submissions of Intervenors

Dr. Booth relied on CAPM, using the same type of equation as Dr. Vilbert but with different parameter values, to derive a cost of equity recommendation for TQM for 2007 and 2008.

According to Dr. Booth, utility stocks have exposure to the bond market which creates sensitivity to interest rates, a sensitivity that is not captured by CAPM. Dr. Booth submitted that a two-factor model partly adjusts for the known estimation problems of CAPM by directly incorporating the risk of the long Canada bond through an interest rate risk premium. The two-factor model of Dr. Booth relied on the following equation:

$$r_e = r_f + (\gamma * IRP) + (\beta * MRP)$$

Where	r_f:	risk-free rate based on Treasury Bills
	γ:	gamma factor
	IRP:	interest rate risk premium (premium over Treasury Bills)
	β:	beta factor
	MRP:	market risk premium (premium over Treasury Bills)

The gammas, as presented by Dr. Booth, were more stable than the equivalent beta estimates. Dr. Booth judged the returns of utility stocks to have about half the exposure to the equity market as the average stock and half the exposure to the bond market as the long Canada bond.

The DCF model was also used by Dr. Booth as a check for his CAPM results and his DCF model was based on composite data and historical growth rates. The opinion of Dr. Booth was that any DCF estimates produced by using unadjusted analyst growth forecasts are seriously in error since it is generally accepted that analysts' earnings forecasts are biased high.

Dr. Booth submitted that Dr. Vilbert's ECAPM estimates are biased high since they rely on a 1 per cent add-on to the risk-free rate which is only valid if the short-term Treasury Bill yield is used as the risk-free rate, whereas Dr. Vilbert used the long Canada bond yield.

According to Dr. Booth, there is no indication that the utilities' betas are reverting to 1.0 as suggested by Dr. Kolbe. Consequently, Dr. Booth's view was that it is illogical to weight them with 1.0 as an "adjusted beta", as suggested by Dr. Kolbe, since there is no expectation that their risk is increasing to that of an average firm in the market.

4.2 Cost of Debt

In computing ATWACC of the sample companies, Dr. Vilbert used an estimate of the market cost of debt for each sample company. The estimation was based on the current yield on an index of utility bonds corresponding to each sample company's debt rating. No party disputed the use of these values.

4.3 Capital Structure

Submissions of TQM

The capital structure used when estimating the ATWACC of sample companies should, as submitted by Dr. Kolbe, reflect the level of risk in the cost of equity estimate. He stated that risk level depends on the sample company’s market-value capital structure, not its book-value capital structure since beta and the resulting cost of equity depend on the market value of the firm’s leverage.

It was Dr. Kolbe’s opinion that market values directly determine the amount of financial risk equity investors actually bear. If a firm is partly financed by debt, as the total market value of the firm fluctuates, the market value of equity will fluctuate more than the market value of the firm. This leverage illustrates financial risk.

Dr. Kolbe stated that the use of market-value weights to calculate the ATWACC for rate-regulated companies would not be circular or lock in an excessive return. Furthermore, the use of market-value weights to calculate ATWACC would not imply an abandonment of regulation based on book value. Dr. Kolbe’s view was that it is absolutely standard in rate regulation, even in North America, to apply a market-derived rate of return to a book-value rate base.

TQM argued that the U99099 Decision from the Alberta Energy and Utilities Board (EUB) (as it was then) accepted the ATWACC concept but applied it using book-value capital structure since it interpreted the specific terms of its enabling statute as requiring that the return on capital be on the book value of the rate base, and not the market value. TQM noted that the *National Energy Board Act* does not dictate the methodology to determine just and reasonable tolls.

When calculating CAPM and ECAPM estimates, Dr. Vilbert estimated each company’s average market value of equity over the most recent five-year period in order to match the estimated betas to the degree of financial risk present during the period of estimation. Dr. Vilbert contended that this matching was optimal.

Submissions of Intervenors

Dr. Booth noted that the NEB’s mandate is to set just and reasonable tolls and it should not be concerned with maximizing or enhancing shareholder value. If the Board wants to rely on ATWACC to estimate TQM’s cost of capital, it should rely on the book-value weights of the sample companies since these weights should be approximately equal to the market-value weights in the long run. CAPP argued that the EUB in the U99099 Decision said it would be derelict in its responsibility to use market-value weights in cost of service regulation, a position which according to CAPP should be adopted by the NEB. An ATWACC methodology based on market weights is fundamentally incompatible with the Canadian cost of service model of pipeline regulation.

According to Dr. Booth, the financial risk stems from the imposition of fixed interest charges since the firm has to pay these interest charges prior to distributing equity returns. This risk does not change as the market value of the firm changes; it only changes when book values change. As a result, financial risk only depends on the book value of a firm's capital structure. CAPP argued that using market weights would be unsustainable if market values were to fall. If this were to happen, CAPP submitted that utilities would revert to the age-old utility concern for a return sufficient to maintain financial integrity and the ability to attract capital under all market conditions. Furthermore, CAPP was of the view that relying on market value would promote circularity because investor expectations, as reflected in market values, would be confirmed. This, in turn, would lead to even higher market values, which would translate into still higher returns in the next regulatory proceeding. Ultimately, this would delay the adjustment to a fair and reasonable value for the allowed ROE.

4.4 Corporate Income Tax Rate

Dr. Vilbert used TQM's estimated marginal income tax rate of 31.9 per cent when calculating the after-tax cost of debt for the comparable companies.[21] No parties disputed the use of this value.

Views of the Board

In Chapter 3, the Board stated that it will use an ATWACC approach when determining TQM's cost of capital for 2007 and 2008. As is evident from the diverging views on the different ATWACC parameters discussed above, an ATWACC approach can be implemented in various ways. In the Board's view, these various ways could each represent a different ATWACC methodology. The Board will explain below its views on the various aspects of the ATWACC methodology for its determination of TQM's cost of capital.

Cost of Equity Methods

The Board is of the view that CAPM is widely accepted as a cost of equity model. This model has been relied upon by the Board in previous proceedings and was not contested in this proceeding as a method to estimate the cost of equity. In the Board's view, CAPM captures the risk equity holders have to bear when holding a common stock.

The Board notes Dr. Vilbert's position that ECAPM results deserve the most weight because this method adjusts for the empirical shortcomings of

21 TQM submitted that the income tax rates of its two partners average 32.185% for 2008. This differs by 0.285 per cent from the estimate used by Dr. Vilbert.

CAPM. In the Board's view, the fact that the long-term risk-free rate is used in CAPM already corrects for the empirical findings of this model, albeit possibly not perfectly. In order to rely on ECAPM to correct for this potential imperfection, the Board would need to be persuaded that the residual empirical shortcomings of CAPM, after using the long-term risk-free rate, are significant. The Board is of the view that the evidence presented in this proceeding did not enable the Board to make such a finding. As a result, the Board will not rely on ECAPM when using the ATWACC methodology.

The Board notes that both Dr. Vilbert and Dr. Booth have relied on the DCF model as a check on their results which are based on the methods discussed above. In the Board's view, even if the DCF model is intuitive and theoretically sound, challenges remain in its applicability since historical growth rates might not reflect the future and analyst expectations might be different than the aggregate expectations of all financial market participants. As a result of these challenges, the Board will not rely on the DCF model and will be informed by CAPM when estimating the cost of equity of sample companies using the ATWACC methodology.

In the Board's view, the cost of equity for utilities regulated on a book-value rate base is influenced by equity market fluctuations as well as bond market fluctuations. The Board finds that a model that successfully combines the two aspects would be useful to adequately consider the specific behaviour of a utility stock. The Board is of the view that a two-factor model offers a more intuitive approach to address the issue of interest rate sensitivity, but such a model is not sufficiently tested to be relied on in this proceeding. On the other hand, the Board was not persuaded that adjusted betas would adequately address the issue of interest rate sensitivity since that approach is an *ad hoc* rather than a systematic adjustment of an appropriate magnitude. The Board does not believe that TQM has demonstrated that utility betas ultimately revert to one, an assumption on which adjusted betas rely. When determining TQM's return, the Board will allow for interest rate sensitivity in the cost of equity estimates since, in the Board's view, the reliability of the estimates is improved with the recognition of the interest rate sensitivity of utility stocks.

Cost of Debt

The Board notes that the market cost of debt was assumed to be equal to the current yield on an index of utility bonds corresponding to each sample company's debt rating. In the Board's view, this assumption is reasonable given the considerable effort required to calculate the actual market cost of debt of each individual sample company. Accordingly, the Board accepts the estimated market cost of debt in the estimated ATWACC of sample companies.

Capital Structure

In the Board's view, one of the benefits of relying on an ATWACC approach is that it allows the Board to compare returns from different investment opportunities irrespective of financing decisions. This is consistent with the way decisions are usually made in the business world. ATWACC enables the comparison of returns while controlling for financial risk. As a result, the weights of the capital components used in calculating ATWACC should reflect the financial risk each of those components bear in a company's capital structure.

The Board notes that there have been two interpretations of financial risk presented in this proceeding:

- financial risk can be the variability of equity value resulting from the variability of the market price of a firm; or
- financial risk can be the variability of income to equity holders arising from the firm's fixed financing costs.

In the RH-4-2001 Decision, the Board expressed the view that financial risk is the risk inherent in a company's capital structure.[22] The Board was also of the view that financial risk increases as the proportion of debt increases in relation to shareholders' equity because debt interest and repayment obligations must be met irrespective of the overall profitability of the business. This definition is closer to the second interpretation of financial risk described above.

As explained in the *Cost of Equity Methods* Section in the Views of the Board above, the Board finds that the present value of the expected cash flows of a firm is an intuitive approach to estimate its current market value. However, the Board notes that markets have shown that the true model determining stock prices is more complex than the intuition implied by the present value of the expected cash flows. On balance, the Board is of the view that even though the present value of expected cash flows cannot determine the value of all firms in all circumstances, it is nonetheless a widely accepted principle in financial theory. This conclusion implies that the variability of future income, as expressed in the second interpretation of financial risk above, can be a reasonable representation of the market price of an asset. As a result, the Board concludes that the two interpretations of financial risk are consistent and the Board need not change its definition of financial risk which it expressed in RH-4-2001.

When drawing ATWACC information from sample companies, the Board is of the view that market-value weights should be used to emulate the

22 RH-4-2001 Reasons for Decision, *supra,* footnote 9, at p. 34.

actual financial risk which each capital component bears. In the Board's view, market values reflect the level of financial risk that equity holders bear for the sample companies. These market values, and ultimately the financial risk, are determined by aggregate expectations of all financial market participants. Furthermore, although the Board is conscious that trends in market valuation are not mitigated by using five-year averages, nonetheless, the Board finds that the reliance on a five-year average market-value capital structure mitigates the risk that a short-term anomaly in the share price of a sample company could unduly impact cost of capital estimations. In choosing to use market-value weights in determining the ATWACC of comparable companies, the Board is not concerned about the circularity that this could create since, in the Board's view, a firm's cost of capital, whether the firm is regulated or not, is determined by investors' expectations as observed in the financial markets.

The Market-Based ATWACC Methodology

In the Board's view, no methodology is a perfect means to implement an ATWACC approach; each methodology has benefits and shortcomings.

Based on the findings of this chapter, the Board has decided to rely on a market-based ATWACC methodology to interpret the information that can be extracted from different samples comparable to TQM and from the financial markets as a whole. The additional insights provided by the market-based ATWACC methodology concerning the workings of the financial market and their resulting impact on financial risk to equity holders significantly influenced the Board's determinations in this proceeding. CAPM will inform the Board's views on the market cost of equity. Further, this cost of equity and the after-tax market cost of debt, when combined with market-value capital structure, will produce the aggregate cost of capital for sample companies.

Chapter 5

Business Risk

The reliance on the ATWACC approach and the market-based ATWACC methodology requires a business risk assessment for two purposes. It is needed in order to identify firms with comparable risk, and to assess changes to TQM's risks since 1994. In these Reasons for Decision, the discussion of business risk has been divided into an assessment of supply risk, market risk, regulatory risk, competitive risk and operating risk. The various forms of risk are in some cases inextricably linked, and the boundaries between them are subjective. To avoid duplication, each concept is presented under only one form of risk, although the Board may have considered it under various forms.

5.1 Short-term vs. Long-term Risk

The concept of short-term versus long-term risk can assist in the presentation and analysis of business risks.

Submissions of TQM

To distinguish between the nature of various business risks, TQM characterized short-term risks as affecting year-to-year earnings of a pipeline or utility, and long-term risks as taking place over a period of time and causing permanent changes in the economic vulnerability of the regulated entity. TQM emphasized that these terms are not meant to distinguish between the time horizons, as long-term risks can still be realized in the short or medium time horizon and short-term risks can continue to be borne out in the longer time horizon. Dr. Carpenter, on behalf of TQM, suggested that Dr. Booth's characterization of short and long-term risks, outlined below, was consistent with TQM's.

TQM agreed with the view of its expert witness, Dr. Carpenter, that long-term risks should be given more weight when conducting comparative business risk analysis. Dr. Carpenter submitted that what distinguishes pipelines from other investments is their long-term sunk investment nature, and that short-term variability in the earnings of an equity investment is only a small part of the business risk picture. TQM also submitted that regulation can play a role in reducing short-term risk of earnings volatility but cannot ensure the long-term return on and of capital.

As an equity investor in a pipeline, TransCanada stated that its primary concern is the long-run return it expects to earn relative to the long-run risks it must bear. TransCanada suggested that this is quite a different perspective from bond holders who view differences in short-term earnings variability as a material difference. It emphasized that credit rating agencies are specifically concerned with the risks to bond holders. TransCanada acknowledged that a business with a higher risk from a debt holder's perspective would need to be compensated in the form of a higher return to avoid deterioration of credit quality.

Submissions of Intervenors

Like TQM, Dr. Booth distinguished between short-term and long-term business risks. Although he did not define these terms, he described several short-term risks caused by revenue and cost uncertainty, and submitted that the main long-term risks are bypass risk and capital recovery risk, with the latter driven mainly by the underlying supply and demand of the commodity. In Dr. Booth's submission, regulators have a variety of tools available to protect utilities from risks, and the history of regulation in Canada is that utilities are, in fact, protected specifically through the use of deferral accounts and rebalancing involved with the forward test year methodology. Dr. Booth provided the example of Pacific Northern Gas (PNG) to demonstrate the extent to which Canadian regulators protect utilities. In Dr. Booth's submission, PNG faces the most severe problems of any Canadian utility. Despite the British Columbia Utilities Commission's efforts to address PNG's situation, Dr. Booth suggested that a death spiral remains possible. He submitted that ultimately, there are limits to what a regulator can do, for example, if demand disappears.

In the opinion of Dr. Booth, investors do not always place a greater weight on either short or long-term risks; rather it is case specific. He also contended that the discounting process in security valuation reduces the amount of capital at risk in the future, which implies that if the risk is very far off, then it can effectively be ignored.

Dr. Booth expressed the view that equity and bond holders have very similar perspectives on long-term risk, although he suggested that bond holders take a more diligent long-term perspective. With respect to short-term risks, he suggested that bond investors generally look at cash flows and are more focused on fundamentals. He submitted that equity markets are influenced less by institutional investors, and that while equity markets are intrinsically long-term oriented, they react very violently to short-term swings in earnings. This is because they readjust their expectations about the future which is generally very difficult to predict. However, for utilities, Dr. Booth indicated that this is less true since low earnings caused by a factor such as weather shouldn't change expectations of the future.

Dr. Safir contended that Dr. Carpenter's distinction between short and long-term time horizons is inappropriate, since ultimately, risk realization over the long-term is just a culmination of yearly comparisons of actual and allowed returns.

5.2 Supply Risk

Supply risk is the risk that the physical availability of competitively priced natural gas volumes could affect TQM's income-earning capability.

Submissions of TQM

TQM indicated that its long-term business risk has increased, in part, due to an increase in its supply risk. As evidence, TQM indicated that WCSB supplies have declined since 2001 and that the projection is for a sustained production decline of conventional natural gas. Volatility in gas prices renders development of unconventional gas uncertain, further contributing to increased supply risk.

In TQM's view, the underlying natural gas market environment in North America has changed since 1994. In 1994, the WCSB was described as a prolific, low-cost supply basin with no significant supply risk. In this proceeding, the evidence of Dr. Carpenter indicated that the North American gas market now reflects greater supply and market uncertainty and that tighter supply/demand balances have led to substantially increased prices and price volatility.

In support of its position on gas supply, TQM submitted a Throughput Study prepared by TransCanada. This included an assessment of natural gas available to TQM via the TransCanada Mainline, which delivers gas produced in the WCSB. The study took into consideration both conventional and unconventional WCSB gas supply, potential Northern gas supply, the level of western Canada demand for natural gas, and possible imports of liquefied natural gas (LNG). The study investigated three cases: Base, Low and High to address the uncertainty with respect to gas supply.

TransCanada concluded that the WCSB is maturing and that production from conventional sources has already peaked. It submitted that this basin maturation and production decline is evident from the following factors:

- total productivity is declining;
- production decline rates for individual wells continue to increase;
- initial well productivity continues to decrease;
- the Reserves Life Index has remained constant while annual gas well connection rates have increased significantly from 2,700 in 1990 to 15,900 in 2007; and,
- finding and development costs continue to increase, making it difficult for industry to grow production.

All of these factors are contrary to the expectations of 1994, the time period with which this application must be compared.

For unconventional resources of CBM and tight gas, TransCanada submitted that most of the gas from those two sources was not considered to be economically viable, with current technology, within the forecast period. As for shale gas development, TransCanada's view was that while there is a possibility for such development, it is too early to estimate volumes. Shale gas in western Canada was projected by TransCanada to commence production in 2008 and to increase by a small amount to 2012.

Mackenzie gas flowing into Alberta was accounted for in TransCanada's projection, with a start date of 2014/15. No Alaska gas flowing into Alberta was accounted for in TransCanada's projection as that too was considered to be speculative at the time of filing.

During the proceeding, TransCanada acknowledged the possibility of gas resources being developed in Quebec, either from conventional or unconventional sources, and that its 2008 supply forecast would show a small volume of gas from Quebec sources due to recent developments in the province. However, TransCanada considered the volumes to be speculative and noted that there was no certainty that any Quebec volumes would even be connected to TQM, since they could connect directly to Gaz Métro.

The flow rates for supply from the various regions are provided in Table 5-1, while estimates of ultimate potential for the regions and gas types are shown in Table 5-2.

Table 5-1
TransCanada's Estimated Flow Rates of Gas Supply
10^6m^3/d (Bcf/d)

	Base Case			**Low Case**			**High Case**		
Region/Type	**2006**	**2012**	**2020**	**2006**	**2012**	**2020**	**2006**	**2012**	**2020**
WCSB Conventional	466 (16.4)	431 (15.2)	293 (10.3)	466 (16.4)	357 (12.6)	279 (9.9)	466 (16.4)	470 (16.6)	398 (14.1)
WCSB CBM	11 (0.4)	37 (1.3)	59 (2.1)	11 (0.4)	28 (1.0)	51 (1.8)	11 (0.4)	51 (1.8)	88 (3.1)
WCSB Shale Gas	0	NA	NA	0	0	NA	0	NA	NA
Mackenzie	0	0	34 (1.2)	0	0	23 (0.8)	0	0	51 (1.8)
Alaska	0	0	130 (4.6)	0	0	NA	0	0	NA
Canaport LNG	0	NA	20 (0.7)	0	NA	20 (0.7)	0	NA	8 (0.3)
Quebec LNG	0	8 (0.3)	10 (0.4)	0	0	0	0	14 (0.5)	20 (0.7)

NA Not Available

Table 5-2
TransCanada's Estimate of Ultimate Potential of Natural Gas
10^9m^3 (Tcf)

Region/Type	**Base Case**	**Low Case**	**High Case**
WCSB Conventional- Technical	8,952 (316)	7,853 (277)	10,595 (374)
WCSB Conventional- Economic	7,839 (277)	7,326 (259)	8,586 (303)
WCSB CBM	635 (22.4)	NA	1,071 (37.8)
WCSB Shale Gas	NA	NA	NA
Mackenzie	1728 (61)	878 (31)	1728 (61)

TQM/TransCanada provided evidence on its ability to access other gas supplies including gas delivered to TQM from Dawn in Ontario, LNG from Quebec facilities or imported gas from the New England region via PNGTS.

Dawn has access to gas from the Rockies, Mid-Continent, WCSB and Gulf Coast regions. However, gas from those sources, delivered through Dawn, would not be as cost effective as past WCSB supplies.

As to the possibility of LNG from Quebec, there is uncertainty as to whether facilities will be constructed, notwithstanding the fact that the Board approved a new receipt point at the proposed Gros Cacouna LNG terminal. The Rabaska project intended for LNG imports may or may not materialize. TransCanada stated that there is a risk that it will not be built, or if built, whether supply would be delivered on a regular basis. In its Throughput Study, TransCanada assumed, in its Base Case, that one LNG import facility in Quebec would start operations in 2012. In the

High Case, LNG capacity would be twice that of the Base Case, while the Low Case would have no LNG coming into Quebec.

For gas imports from the New England region to materialize, PNGTS would need to be physically reversed. Any imported volumes would depend on volumes of LNG imports into facilities in that region, or into facilities in Atlantic Canada, such as Canaport LNG Terminal (Canaport), which would be importing LNG for the purpose of supplying the New England region.

TransCanada concluded that the possibility of any sources of supply, other than from the WCSB, flowing on TQM is uncertain.

Submissions of Intervenors

No intervenors provided evidence contrary to the WCSB conventional and unconventional supply evidence provided by the Applicant. This includes the estimates of ultimate potential, the changed supply outlook, and the increasing costs for new supplies. With respect to WCSB gas supply, CAPP noted the rapid development of shale gas resources in northeast B.C. as proof that the basin has additional potential for new gas supplies that where not fully recognized by TransCanada. CAPP argued that TransCanada did everything possible to cast a negative view on shale gas in this hearing. Local Quebec shale gas and conventional gas should also be recognized as a potential supply source, although volumes are likely to be low.

CAPP focused on the role of Dawn in diversifying TQM's supply, the role of LNG imports into the region, PNGTS reversibility and the recent proposals to connect Alaska gas to the TransCanada Mainline in its argument over supply. CAPP questioned TQM on the amount of supply that it is currently getting from Dawn. Dawn, itself, can access conventional and unconventional gas from the WCSB, Rockies, Mid-Continent and Gulf Coast, including LNG supplies delivered into the Gulf Coast or Mexico. Reversal of flows on the PNGTS would allow TQM to access gas from U.S. supply basins and to access LNG delivered into the U.S. Northeast or into Atlantic Canada. CAPP, IGUA and Ontario all suggested that this diversification of supply has, in fact, decreased the overall supply risk for TQM.

On the issue of underlying changes to the North American gas market, Dr. Safir, on behalf of CAPP, disputed TQM's view that prices are more volatile and uncertain and specifically took issue with the appropriate measure of volatility. Dr. Safir stated that the best statistical measure of volatility is the coefficient of variation rather than the standard deviation method used by TQM.

TQM's Reply

TQM stated that access to non-WCSB supplies at Dawn provides some supply flexibility to TQM (as compared to the Mainline markets upstream of Dawn), but that comes at the cost of putting at risk the future application of the integrated Mainline concept for TQM's toll design and cost recovery. Increases in tolls to the TransCanada Mainline would impact tolls to shippers with delivery points off the TQM system as well. Declining throughput on the Mainline, resulting from the declining supplies from the WCSB, would result in increasing tolls on the Mainline. In addition, sourcing gas at Dawn could displace some of the long-haul throughput on the Mainline. This would increase tolls and hence, the delivered price of gas in Quebec, making gas less competitive in the markets served off the TQM system, including the PNGTS Extension. TQM noted that the TransCanada Mainline toll to the Eastern Zone has increased from 90 cents per GJ in May 1995 to $1.40 per GJ. TransCanada's view remained that the majority of gas sourced at Dawn would continue to be WCSB sourced gas. In addition, TQM argued that long-haul shippers on the Mainline would be dissatisfied in sharing the costs of the TQM system if suppliers to TQM are only using the Mainline downstream of Dawn and are only paying short haul tolls.

In response to Dr. Safir's concerns about the calculation of price volatility, Dr. Carpenter indicated that standard deviation is a measure of absolute price volatility which makes it more relevant than using the coefficient of variation which measures relative variation. Dr. Carpenter reasoned that it is absolute price risk that concerns customers.[23] He further asserted that utility hedging programs have grown during this decade and that this would be evidence that absolute price volatility is the relevant measure for end-use customers.

5.3 Market Risk

Market risk has two aspects: the business risk that results from the overall size of the market and the risk which results from the pipeline's ability to capture market share. The issue of market share, including the ability of natural gas delivered by TQM to compete in the Quebec market against alternative fuels and the ability of TQM, via its PNGTS extension,[24] to capture market share in the New England market will be discussed in Section 5.4, Competitive Risk.

Submissions of TQM

The position of TQM was that expected natural gas consumption growth in Quebec has failed to materialize, and in particular, losses in industrial loads since 1994 have resulted in significant uncertainty around the future use of TQM's assets to serve gas customers in Quebec.

TQM serves the Quebec market via Gaz Métro's local distribution system. Gaz Métro delivers 97 per cent of the gas volumes consumed in Quebec. TQM's evidence with respect to the Quebec market was based on Gaz Métro's historical usage and forecasts. Dr. Carpenter, on behalf of TQM, presented the historic, normalized natural gas usage per customer for several rate classes in Gaz Métro's market area, which showed a declining trend of utilization since 1994.

TQM has a relatively large resource-based industrial load which tends to be more variable and unpredictable than the residential and commercial sectors. TQM's evidence, based on Gaz Métro's historical usage, showed a decline in industrial customers and gas consumption since 1994. Electric power generation is a relatively new sector in Quebec, increasing the potential demand for natural gas. The Bécancour power generation station began operation in September

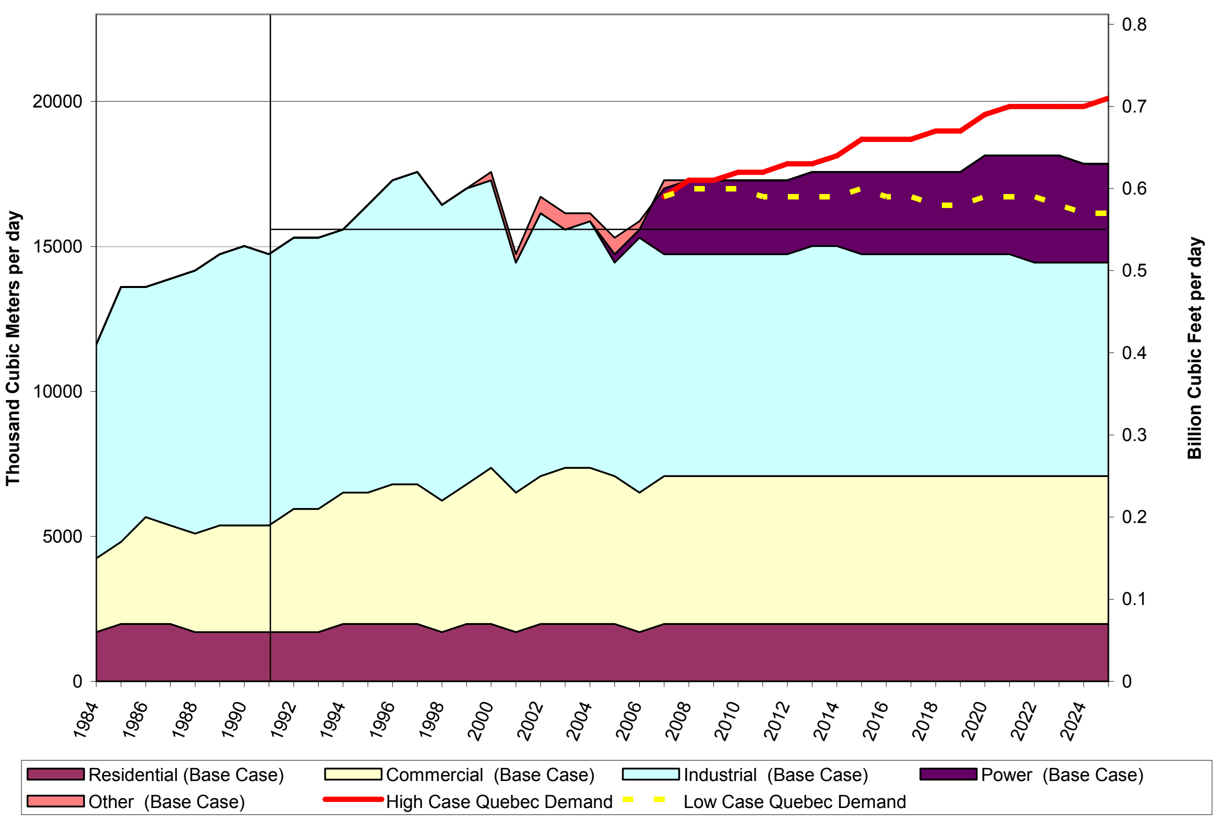
23 As an example, he asserts that a $1.50/Dth increase to an underlying $8/Dth price (yielding a cost of roughly 20 per cent) should not be considered less risky than a $.70/Dth increase to an underlying $2.20/Dth price (yielding a cost of roughly 30 per cent).

24 In 1997, the Board approved the construction and operation of additional natural gas transmission facilities to extend the TQM system from Lachenaie to East Hereford, near the Canada-United States border. This extension connected the TQM system to the PNGTS to serve markets in the U.S. Northeast. National Energy Board, GH-1-97 Reasons for Decision, Trans Québec & Maritimes Pipeline Inc. PNGTS Extension Facilities, April 1998.

2006 and was expected to make up for reduced demand in other industrial sectors since 1994. However, the Bécancour power generation plant suspended operation in 2008, making its future usage uncertain.

The Throughput Study offered three cases for Quebec gas demand. The Base Case showed 0.4 per cent annual average growth in Quebec demand, with relatively flat industrial demand at the lower end of its historical range. The High Case showed a one per cent annual average growth rate, and the Low Case showed a 0.2 per cent annual average decline rate. TransCanada did not forecast Quebec demand, by sector, for the High and Low Cases. Instead, overall Quebec demand was adjusted in the High and Low Cases to simulate a range of outcomes that TransCanada judged to be reasonable. Figure 5-1, below, shows TransCanada's forecast and historical natural gas use, by sector, in Quebec. Actual deliveries via TQM are a portion, albeit a considerable one, of the total Quebec demand.

Figure 5-1
Quebec Natural Gas Demand by Sector



Source: TQM Application

Submissions of Intervenors

In CAPP's opinion, there has been no change in TQM's market risk since 1994, and its position was supported by the evidence of Dr. Safir, Dr. Booth and IGUA. Dr. Safir stated that the demand for gas in Quebec has remained relatively stable since 1989 and TQM has actually been able to increase its deliveries and capacity utilization over the intervening years. Dr. Booth and Dr. Safir stated that they expected demand would not be significantly different in the future.

CAPP added that the risk from the large industrial load has not increased since 1994 and that the lack of market diversification and the volatile, resource-based large industrial load was previously identified as a risk by TQM in 1994. There has been little historical, and no forecast change in Quebec demand mix among the residential, commercial and industrial sectors. On behalf of CAPP and IGUA, Mr. Trahan stated that he believed that the Bécancour electric power generation plant would return to production in 2010.

CAPP maintained that if the 2025 throughput, as forecast in the Base Case at 12.75 10^6 m^3/d (0.45 Bcf/d), were reduced to remove power generation entirely and further reduced for any remaining PNGTS export flow, the throughput is comparable to the 1994 throughput at around 8.5 $10^6 m^3/d$ (0.30 Bcf/d) compared to 8.22 $10^6 m^3/d$ (0.29 Bcf/d) in 1994.

Industry restructuring since 1994 has helped Quebec industrials compete and to be better positioned to do so in the future, explained IGUA. It further suggested that prospects for industrial load growth are favourable but provided no supporting economic forecast. IGUA also noted that the Gaz Métro forecast was for higher industrial growth in the near term than the TransCanada forecast, at 4.17 per cent per year between 2008 and 2011.

TQM's Reply

TQM was of the opinion that although TQM's overall usage has not declined (distributed volumes have remained flat over the last 14 years), the evidence also shows that both Gaz Métro and TQM had to considerably increase investments in their systems to maintain the same level of throughput. TQM's capital investments have included the tunnel from Québec City to the south shore of the St. Lawrence River in 1995/96, the 2006 Lachenaie compressor station expansion in Quebec and the addition of Montréal East as a delivery point along the TQM PNGTS extension. Gaz Métro has increased investments in its system by 45 per cent to maintain and grow its market

TQM also noted that IGUA was unable to provide data in support of its position that industrial demand in Quebec will increase because plant closures and rationalizations have been completed and as a result demand could only go up.

TQM said that the Quebec Régie de l'énergie (Régie) found that since 1999, the risk to the Quebec gas market had increased. The Régie cited higher, more volatile gas prices, the impact of these prices on competition with other sources of energy, and concern over the loss of industrial volumes.

5.4 Competitive Risk

Competitive risk refers to the business risk resulting from competition for customers at both the supply and market ends of the pipeline system. It directly affects business risk by providing customers with alternatives to ship or purchase natural gas. In these Reasons for Decision, the issue of market share, which includes the ability of natural gas delivered by TQM to compete in the Quebec market against alternative fuels, and the issue of the ability of TQM, via its PNGTS extension, to capture market share in the New England market are discussed as part of competitive risk.

5.4.1 Alternative Fuels

Submissions of TQM

TQM submitted that over the long-term it will lose markets to competing fuels and to competing pipelines. TQM stated that the decline in natural gas usage in the Quebec market has been driven by a decline in the competitiveness of natural gas relative to electricity and fuel oil. It now has substantially greater risk that is unique to TQM. Industrials have decreased the size of operations in response to both macroeconomic conditions and fuel costs.

The declining competitiveness of natural gas in the Quebec market is in part driven by absolute price as well as by the stability of the price of electricity relative to the volatility in the natural gas price.

Gaz Métro estimated that approximately 90 per cent of its interruptible customers have the ability to switch to an alternate source of energy and the vast majority of these customers would switch to fuel oil, if it were economic to do so. At the end of 2007, Gaz Métro had 206 interruptible customers corresponding to annual consumption of 943.32 10^6m^3 (33.3 Bcf).

TQM stated that electricity has historically been priced lower than natural gas in the Quebec market. Furthermore, TQM submitted that electricity prices receive an effective subsidy as a result of provincial policy. The lack of competitiveness of natural gas is likely to continue, argued TQM, as Quebec residential electricity rates are forecast to remain stable and predictable with an approximate annual increase of two per cent, which is less than the current rate of inflation.

Submissions of Intervenors

Dr. Safir stated that there was no real indication that the relative attractiveness of natural gas will fall in the future. The projection of the relative price of natural gas to residual fuel oil, used in the Throughput Study is lower than historical levels over the past 12 years. Over the past few years, the relative price of electricity for residential consumers has increased. Furthermore, Dr. Safir stated that the historical disadvantage of natural gas compared to electricity is already factored into equity thickness awarded to TQM in RH-2-94.

In IGUA's opinion, the Throughput Study did not sufficiently factor in the migration to natural gas of some of the volumes that were lost to #6 Fuel Oil since early 2000. The past competitive disadvantage of natural gas to #6 Fuel Oil has been significantly reversed recently. In addition, the program from the Agence de l'efficacité énergétique will reduce barriers to more Quebec industrials choosing natural gas. During the hearing, IGUA said the Quebec Energy Strategy and the financial incentive from the Green Fund will encourage industrial customers to switch from oil products to natural gas. Mr. Trahan submitted that, while these programs will improve the competitive position of natural gas, natural gas is still at a disadvantage in Quebec to electricity but that gap would narrow because of those policies. Furthermore, IGUA argued since these programs and incentives did not exist in 1994, this aspect of TQM's market risk has actually declined. The Green Fund program is voluntary and the offer of subscribing to the program started in June 2008, and therefore, it was not possible to yet determine the level of participation.

IGUA explained that many industrials have separate thermal and electrical needs that are not interchangeable and that switching between natural gas and electricity is not possible. For some industrials, natural gas may be required for very specific applications that do not allow the use of alternative fuels. Electricity is not a direct competitor for industrial heating load needs. IGUA discussed how the magnitude of the costs to convert a plant from one fuel to another means that such investment decisions are not undertaken lightly; they are made based on a long-term analysis, not on any short-term volatility risk. Once a fuel decision is made and the capital invested at a particular location, the likelihood of reconfiguring a plant to a different fuel is unlikely. Furthermore, the Quebec government will limit the amount by which individual customers may convert energy sources to electricity service for existing operations. The new ceiling for an individual company will be set at 50 MW, down from the previous 175 MW.

The IGUA and CAPP witnesses discussed how, beyond 2008, the price of electricity in Quebec will rise as a consequence of the heritage supply now being capped, and the stated intent within Quebec of moving electricity consumers towards true cost pricing as a method of encouraging energy conservation. This will reduce the favoured pricing of electricity relative to natural gas in the future.

Ontario stated that a transformation is occurring within the Quebec electricity sector which will reduce the historic risk that natural gas faces when competing against electricity. Ontario also submitted that the overall level of risk TQM faces from electricity within the Quebec residential, commercial and industrial sectors has declined. Furthermore, the Quebec government's programs to reduce the reliance of industry on heavy fuel oil, and Gaz Métro's environmental initiatives, improve prospects for natural gas consumption and reduce TQM's risk.

TQM's Reply

Although recent environmental programs and policies instituted by the Quebec government favour cleaner energies such as natural gas, and may promote fuel switching from fuel oil to natural gas in the near term, it was TQM's view that such programs, over the medium to long-term, would encourage an overall switch from carbon-based fuels to electricity. Furthermore, it stated that hydroelectricity surpluses are expected to remain in Quebec, which is confirmed by the closure of the Bécancour power generation plant. TQM noted that gas consumers' annual contributions to the Green Fund were approximately $40 million, while electricity consumers were not required to make any contribution. Those contributions from gas consumers alone have caused an increase of two per cent in Gaz Métro's rates for 2008.

5.4.2 Market Competition and Export Risk for PNGTS

Treatment of PNGTS

Submissions of Intervenors

CAPP noted that neither TQM, nor TransCanada for its Mainline, requested a change in their capital structure when TQM applied to build the PNGTS extension. CAPP and Dr. Safir asserted that this makes TQM's argument that the PNGTS extension increased its risks unpersuasive, and implies that the real question is only whether the risks related to the PNGTS extension have materially increased since the application to construct the facilities was made.

TQM's Reply

Recent environmental programs and policies instituted by the Quebec government favour cleaner energies such as natural gas, and may promote fuel switching from fuel oil to natural gas in the near term. It was TQM's view that such programs, over the medium to long-term would encourage an overall switch from carbon-based fuels to electricity. TQM noted that at the time of the application for the PNGTS extension, it had not been very long since the release of the RH-2-94 Decision, and argued that the RH-2-94 Formula returns were considered more reasonable at that time than they are today. Dr. Carpenter argued that following Dr. Safir's logic would imply that regulators would never consider changed circumstances in evaluating a company's allowed return.

Market Competition and Export Risk for PNGTS

Submissions of TQM

TQM argued that the business risk associated with TQM's PNGTS extension is a function of the competition for export demand in the New England market that did not exist for TQM in 1994. This competition will increase following the completion of the Canaport in New Brunswick, and the completion of other LNG facilities, like Gateway LNG, and pipeline expansions into New England, which will likely take market share away from WCSB gas, delivered via the PNGTS extension.

Dr. Carpenter explained that TQM invested $317 million in the PNGTS extension which now represents 53 per cent of its undepreciated rate base. He further stated that increased competition for transportation volumes through TQM's East Hereford extension increased the risk that costs and return associated with those assets will not be recovered over life of the assets. The Throughput Study forecast declining throughputs, in all cases, on TQM to East Hereford as a result of Canaport imports that were expected to begin in late 2008. The range of uncertainty in these forecasts is demonstrated by the High and Low Case results that depend heavily on whether and when Quebec LNG imports might be connected to and flowing on TQM.

Submissions of Intervenors

CAPP expressed the view that rather than increasing TQM's business risk, the PNGTS extension has provided more and better markets for TQM. Dr. Safir stated that by expanding markets, TQM's risk is either the same as or lower than it was in 1994. Ontario shared this view. Dr. Safir argued that PNGTS was not operationally linked to TQM in 1994, and at that time, there were already risks that throughput levels on TQM could fall. TQM achieved growth beyond what was expected in 1994 and if throughput were to fall back to levels originally anticipated, TQM should not claim that it is in a more adverse position than when its original equity ratio was decided. CAPP argued that the PNGTS extension was presented as a "market opportunity" in 1997, and is now being presented as a "risk".

CAPP also noted that competition from Canaport via the Maritimes and Northeast Pipeline is not new; the risk in 1997 was the expected increase in production from offshore Sable Island. Presently, LNG deliveries at Canaport replace the production expected from Sable Offshore, and there is uncertainty with respect to Canaport volumes achieving levels expected by TransCanada in the Throughput Study. Cross-examination of TQM witnesses by CAPP, revealed the uncertainty in LNG imports to the U.S. Northeast, as existing new LNG facilities have not been utilized to date in 2008. Furthermore, the TQM witnesses discussed the price disparity between low North American gas prices and high LNG prices elsewhere in the Atlantic Basin and Japan.

The number of proposed projects presently coming into service or proposed to serve the U.S. Northeast also did not appear to CAPP to represent an increase in risk to PNGTS. CAPP believed that the availability of Canadian supply for export is the cause of the risk, not competition from other pipes. The High Flow Case of the Throughput Study showed less impact on PNGTS. TransCanada analysed all North American gas flows for its Throughput Study; competition from other projects was not identified as a risk factor in the Northeast market, only LNG deliveries from Canaport.

Finally, CAPP argued that PNGTS was built on 20-year contracts which give high incentive for shippers to use those contracts, and TransCanada, itself, continues to tell the market that PNGTS is among the paths to attractive U.S. markets.

Ontario submitted that the potential volume from Canaport is very small, relative to the New England market it was designed to serve, and therefore, does not increase TQM's risk. Ontario submitted that uncertainty about long-term LNG supplies also stems from the uncertainty of long-term LNG supply contracts for the U.S. LNG terminals.

TQM's Reply

TQM submitted that the overall throughput of TQM remains at 1994 levels only because of the combined demand in the Quebec market and the export market via the PNGTS extension. Furthermore, counsel for TQM argued that Gaz Métro wrote off more than 20 per cent of its investment in the PNGTS pipeline in 2008, which points to a significant change of the circumstances in which PNGTS operates, and to increasing uncertainty with regard to the recovery of the funds initially invested in that system.

TQM explained in reply evidence and in response to information requests, that when the PNGTS extension was being considered, the study completed by TransCanada focused only on natural gas demand in the U.S. Northeast and did not address gas production from Nova Scotia offshore. TQM further explained that, its focus at that time was on finding markets for excess gas supplies from the WCSB, and a forecast of stronger demand growth in the U.S. Northeast.[25] Since that time, the forecasts for WCSB production and western Canadian demand have changed substantially, resulting in lower exports from that region, thereby deteriorating the expectations for stable throughput on the PNGTS extension.

With respect to the risk to PNGTS from LNG imports, Dr. Carpenter responded by stating that the LNG projects that will be competitors for TQM are either completed or under construction, while the projects that would supply TQM are still in the initial development stages or have been suspended.

5.5 Operating Risk

Operating risk is the risk to the income-earning capability that arises from technical and operational factors.

Submissions of TQM

The only submission by TQM on the issue of operating risk was in response to information requests regarding the reversibility of the PNGTS extension. TQM submitted that past evaluations of the reversal of the system found that it was physically capable of back-hauling volumes, and that under certain unusual or emergency conditions it would be possible to back-haul some volumes without any facility modifications. However, TQM stressed that these assessments had not been detailed to the point of examining potential restrictions, such as governmental, regulatory or physical, which might be particularly important in non-emergency type scenarios.

Submissions of Intervenors

CAPP submitted that while TQM remains a single line system, it now has compression which is a new feature compared with 1994. In this regard, CAPP noted that TQM is operated by TransCanada, an experienced operator of compression. CAPP suggested that counteracting these factors is the new operational security from the existence of the PNGTS extension and its potential reversibility. CAPP did not submit a view on whether there has been a net change in TQM's operating risks.

5.6 Regulatory Risk

Regulatory risk is the risk to the income-earning capability of the assets that arises due to the method of regulation of the company.

25 When TQM applied for leave to build the PNGTS extension in 1997, it was expected that this investment would address the lack of market diversification for TQM and the forecasts expected an average annual growth rate of 2.7 per cent in Quebec natural gas demand and 1.0 to 1.7 per cent for the New England market. (See GH-1-97 Reasons for Decision, *supra*, footnote 24, at p.5.)

Treatment as part of the integrated TransCanada Mainline

Submissions of TQM

Since it began operating, the TQM system has been treated as a part of the integrated TransCanada Mainline. The contract underpinning this arrangement, whereby TransCanada holds virtually all of TQM's capacity, commenced in 1982. TQM submitted that this contract has been amended several times since, with the current principal expiration date in 2013, having been agreed to as an extension in 1998 due to the construction of the PNGTS extension. In addition to the principal volumes under contract until 2013, some are also under contract until 2017 and 2018. Individual shippers, rather than contracting directly with TQM, contract with TransCanada for deliveries to points off the TQM system. At present, over 99 per cent of TQM's revenue requirement is recovered from TransCanada in the form of 12 monthly payments, and TransCanada includes these payments in its revenue requirement as a Transmission by Others cost.

Dr. Carpenter presented evidence indicating that the contracts held by shippers on the TransCanada integrated Mainline with delivery points off the TQM system had a weighted average remaining contract duration of 3.2 years as of 15 November 2007. He noted the 2013 expiry of the principal volumes in the contract underpinning the integrated Mainline, and contended that the divergence between the 3.2 years duration and the 2013 expiry introduces uncertainty for the future of the integrated Mainline concept. Dr. Carpenter also submitted that the circumstances at the time when TQM's tolls were first set as part of the integrated Mainline, notably regulated gas commodity prices and the federal government's desire to promote the development of a gas market in Quebec, were much different than today. Another important difference in Dr. Carpenter's view is that unlike in 1994, WCSB supply is no longer growing, nor is there insufficient pipeline capacity out of the basin.

If decontracting were to occur for deliveries either to East Hereford or the domestic Quebec market, TQM argued that TransCanada could face pressure to change the toll design of the Mainline and to remove some or all of the capacity it currently holds on the TQM system from the integrated Mainline. Both Dr. Carpenter and TQM noted that there have been challenges to the integrated Mainline concept. TQM suggested that a variety of future changed circumstances could give rise to additional challenges to the integrated Mainline concept, such as, if volumes decline on the TQM system, if tolls rise on the TransCanada Mainline, or if TQM deliveries are increasingly sourced at Dawn.

If TQM were to be treated on a standalone basis rather than as part of the integrated Mainline, TQM submitted that this would result in higher tolls for deliveries off of TQM, thereby harming the competiveness of the TQM system. TQM submitted a range of potential toll impacts based on varying assumptions.

Submissions of Intervenors

In the submission of Dr. Booth, because of the contract TransCanada holds for TQM's capacity, TQM is protected from revenue fluctuations due to variances in throughput as well as from shipper-credit problems. CAPP cited the RH-2-94 Reasons for Decision in stating that the arrangement "dilutes TQM's high unit cost and provides the Company with a high degree of assurance that its costs will be recovered."[26] CAPP argued that the NEB has been clear and consistent in its treatment of TQM as part of the integrated Mainline, and that the Board recently reaffirmed this treatment in the RH-1-2007 Reasons for Decision, which CAPP argued should quieten the debate. CAPP was of the view that the risk of the NEB disallowing this arrangement remains low and has not increased.[27] CAPP also alluded to the potential that in the future, TQM could have high volumes relative to the Mainline, for example as a result of Quebec LNG, such that TQM would benefit from ending the current integrated Mainline concept.

By virtue of TQM's contract with TransCanada, IGUA argued that TQM has been insulated from the impacts Gaz Métro experienced from industrial load losses, and continues to benefit from full assurance of cost recovery. IGUA also argued that this arrangement, which is not at risk of changing, is the biggest reason why TQM's overall risks have changed little since 1994, and until the arrangement changes it remains the overriding consideration for business risk, particularly for 2007-2008.

Ontario argued that it is inconsistent for TQM to suggest that TQM's financial health should be examined on a standalone basis, without influence of its parents, while also suggesting that the Board should consider the contracts held on TransCanada to TQM delivery points rather than only the contracts held on TQM itself. Ontario encouraged the Board to only look at the latter.

Competition between pipelines

Submissions of TQM

In TQM's submission, the 1998 approval of the Alliance Pipeline Ltd. (Alliance) pipeline[28] marked a significant change in Canadian regulatory policy, towards greater competition between pipelines. TQM argued that this increased its risks because of the impact on its access to WCSB gas supplies, the impact on Mainline tolls and hence Quebec delivered gas price, and because it increased the chance that it may face greater competition from other pipelines in the future.

Submissions of Intervenors

Ontario argued that TQM's reliance on the WCSB has ended, because its gas is being increasingly sourced at Dawn. With regard to the approval of Alliance, Ontario argued that it had no impact on TQM's risks.

Other aspects of year-to-year revenue and income risk

Submissions of TQM

TQM submitted that its 2007-2009 Partial Settlement has all the same deferral accounts as its previous settlements, and that these will cover only approximately 20 per cent of its cost of

26 RH-2-94 Reasons for Decision, *supra,* footnote 2, at p. 26.

27 National Energy Board, RH-1-2007 Reasons for Decision, TransCanada PipeLines Limited Gros Cacouna Receipt Point Application, July, 2007.

28 National Energy Board, GH-3-97 Reasons for Decision, Alliance Pipeline Ltd. on behalf of the Alliance Pipeline Limited Partnership Facilities and Tolls, November 1998.

service. TQM noted that it is at risk for in-year variations in depreciation and return, its term loan financial charges, and its fixed cost envelope. With respect to its term loan financial charges, TQM submitted that it had been lucky in the past to have benefitted from the risk, since it is based on the difference between the actual prime interest rates and those forecast by major banks.

With respect to assessing a pipeline's risks based on a comparison of actual and allowed earnings, TQM submitted that such a comparison is not appropriate since it reflects past rather than future circumstances and puts too much emphasis on short-term risks. TQM contended that historical comparisons of actual versus achieved earnings are of limited use in assessing a pipeline's forward-looking business risk, emphasizing that the predictive capability of such information would be dependant on the future earnings drivers being the same as past drivers. With regard to the circumstances which impact its business risk, TQM submitted that it had demonstrated that the future is not similar to the past. In noting that actual ROEs use accounting data, Dr. Carpenter suggested that that they often reflect extraordinary one-time events. TQM argued that accounting data returns are not the relevant measure of returns in assessing TQM's cost of capital; rather, a relevant measure would be TQM's achieved market returns on its unknown market value of equity.

Submissions of Intervenors

CAPP noted that TQM's actual ROE has exceeded its allowed ROE in every year since 1994, and Drs. Safir and Booth and IGUA noted the same going back further, to 1990.

In Dr. Safir's submission, equity investors in regulated companies are informed by variations in actual earnings relative to allowed earnings because they provide information about the level of regulatory risk and hence, possible changes in the valuation of the company. A history of earning allowed returns with little variation is, in his opinion, a strong indication of the effectiveness of regulation and low regulatory risk.

Going back to 1994, Dr. Safir suggested that there has not been any substantive change in the regulatory risk facing TQM, and in his view, TQM's regulatory-sanctioned revenue protections shield it from potential effects of competition. Dr. Safir submitted that by virtue of its recovering nearly all its revenues from TransCanada, TQM is provided with a high degree of assurance of cost recovery and is shielded from throughput fluctuations. According to Dr. Safir, the best evidence of TQM's effective revenue protections is its historical financial performance, and he submitted that between 1990 and 2007, TQM's actual ROE, minus its allowed ROE, was positive at a highly statistically significant level. Dr. Booth also contended that TQM earning above its allowed ROE in every year shows that TQM's risks are not material.

Views of the Board

Short-term vs. Long-term Risk

The Board accepts that it is useful to distinguish between the nature of risks in a manner as TQM and Dr. Booth have done, even if such distinctions may not be precise.

On the question of the appropriate weights for short versus long-term risks, the Board is of the view that because of the more limited ability of regulators to respond to the realization of long-term risks, there is a sense, in this aspect, that they are more important than short-term risks. Long-term risks are more structural. Therefore, they denote more fundamental factors and trends in the evolution of the overall risk landscape of a company, while short-term risks tend to be either more cyclical or individual events. However, the Board notes that generally, the relative importance of short versus long-term risks would depend on the relative probability, size and timing of the potential impacts arising from the specific risks being realized. The Board is of the view that, in practice, a plausible set of circumstances could result in either short or long-term risks weighing more heavily in the risk profile of a specific pipeline. Therefore, the Board finds that it must consider both long-term and short-term risks and weigh them based on the circumstances applicable to the pipeline.

Supply Risk

The Board is of the view that reasonable reliance can be placed on the range of conventional supply estimates as presented by TransCanada and that significant increases in WCSB conventional supply are unlikely. As a result, the Board finds that over the longer term, maintaining flows on the Mainline will depend, in part, on the development of unconventional or Northern supply. That dependence is greater today than was anticipated in 1994.

Unconventional supply, including CBM and shale gas, is more uncertain given their early stages of development. Although unconventional supply is expected to at least partially offset future declines in conventional production from the WCSB, the extent to which it will and when this may occur remains uncertain.

Similarly, gas from the Mackenzie Delta and Alaska may act to offset future declines in WCSB conventional production. Although TransCanada has included Mackenzie Delta gas in its Throughput Study, it is not clear when, or if, this gas will flow, and, if it does, the extent to which it would flow on the Mainline. It also remains unclear as to when, or if, Alaskan gas will flow and, if it does, the extent to which it would flow on the Mainline.

The Board notes that the import of LNG into Quebec is a possibility; indeed it has already approved a receipt point on TQM for the proposed Gros Cacouna regasification facility. Another proposal for a regasification facility, the Rabaska project near Quebec City, already has some approvals in place. The Board agrees with the Applicant that future LNG supply is uncertain, due to the need to confirm supply, finance construction, seek regulatory approvals and construct pipelines to connect the proposed facilities to the TQM system.

On the issue of access to other gas supplies, the Board recognizes that TQM does have access to Dawn, which provides a mitigating factor for physical supply to TQM. TQM acknowledges that about 20 per cent of its gas supply comes from purchases from Dawn. Today, the supply of gas at Dawn is primarily sourced from western Canada. There was discussion by TQM witnesses regarding growing production areas that could supply Dawn. However, these witnesses explained that growing Dawn supplies will impact tolls on the Mainline for long- haul shippers of gas from the WCSB. Ultimately, the Board agrees with the view that, in these circumstances, the higher tolls would be passed on to the markets that are served off of the TQM system, further impacting the competitiveness of gas in the markets that TQM is serving.

In addition, the Board notes that while PNGTS is capable of flow reversal, which would deliver gas into TQM, there are issues involved. For this to occur there would have to be a fundamental change in market and price conditions. The Quebec market would require higher prices than the New England market, and that higher price would likely create an increased market and competitive risk. The Board places little weight on the concept that a potential reversal of PNGTS represents a reduced business risk for TQM.

The Board notes the significant change in the supply picture for the WCSB between 1994 and present day. In 1994, the WCSB was seen as a growing source of low cost natural gas and likely to remain so for some time into the future. Therefore, at that time, it was not considered that Canadian pipelines faced significant supply risks. However, in 2008, conventional production from the WCSB has passed its peak and unconventional supplies remain uncertain. At the time of the hearing, gas prices were significantly higher than in 1994, while the costs to develop new supply had also increased. As a result, industry is challenged to develop new economic supplies of conventional gas resources. Both CBM and unconventional gas in the WCSB remain speculative. For Northern gas, development remains uncertain. For LNG, development of facilities and expected levels of imports into Canada remain unclear at this time.

The Board views the economic supply as a crucial change that has occurred for the TQM system and the Quebec market.[29] Absolute gas price levels are higher, and declining conventional supplies from the

29 The RH-2-2004 Phase II Reasons for Decision, *supra,* footnote 8, at p.27, defines supply risk as the physical availability of natural gas. Also note that the NEB estimates and the CGPC estimates of Canadian resources consist of volumes of marketable gas assumed to be economic under existing and expected future conditions. TransCanada relied upon the CPGC estimates for Canada, which it calls economic.

WCSB have made this source of supply more uncertain than in 1994. Therefore, the Board concludes that the supply risk for TQM is higher than it was in 1994.

Market Risk

The Board notes that Quebec natural gas demand is relatively unchanged since 1994. TQM has a relatively large industrial load which has tended to be more variable and unpredictable than the residential and commercial sectors, as was the case in 1994. Further, the introduction of the Bécancour power generation plant has not made up for the losses in other industrial sectors; its future usage is uncertain. The Board is not persuaded by CAPP's argument that TQM's risk from the large industrial load has not increased since 1994.

IGUA did not provide quantitative support for its view that industrial customers will be better able to compete in the future. Although Gaz Métro, itself, had a more favourable short-term forecast of industrial growth than TQM, the Board finds that this evidence is not determinative of the long-term market risks facing TQM.

In light of the uncertainty of the Quebec industrial and electric power generation sectors demand for natural gas, the Board finds that the TQM pipeline is exposed to increased market risk compared to its position in 1994.

Alternative Fuels

Discussion of the distribution of electricity blocks to industrials and the nature of industrial fuel switching capabilities, provided by IGUA, was useful in enhancing an understanding of the landscape of energy demand in the province of Quebec. In particular the interaction between natural gas and electricity was most useful. The discussion of the Quebec Energy Strategy was also very helpful in understanding government policy impacts on energy demand in the province. It appears the program is too new to assess the actual impact on industrial gas demand.

The Board notes the declining competitiveness of natural gas in the Quebec market. This is, in part, driven by absolute price as well as by the stability of the price of electricity relative to the volatility in the natural gas price. Furthermore, on the residential side, the Board is of the view that this lack of competitiveness is likely to continue. Quebec residential electricity rates are forecast to remain stable and predictable with an approximate annual increase of two per cent.

The Board accepts TQM's arguments that the high industrial load as compared to total system load and the declining competitive position of natural gas compared to alternative fuels are significant risks to the TQM system and these risks have increased since 1994. This was reflected in TQM’s and Gaz Métro’s customer data which showed a decline of about 50 per cent in interruptible customer consumption.

PNGTS

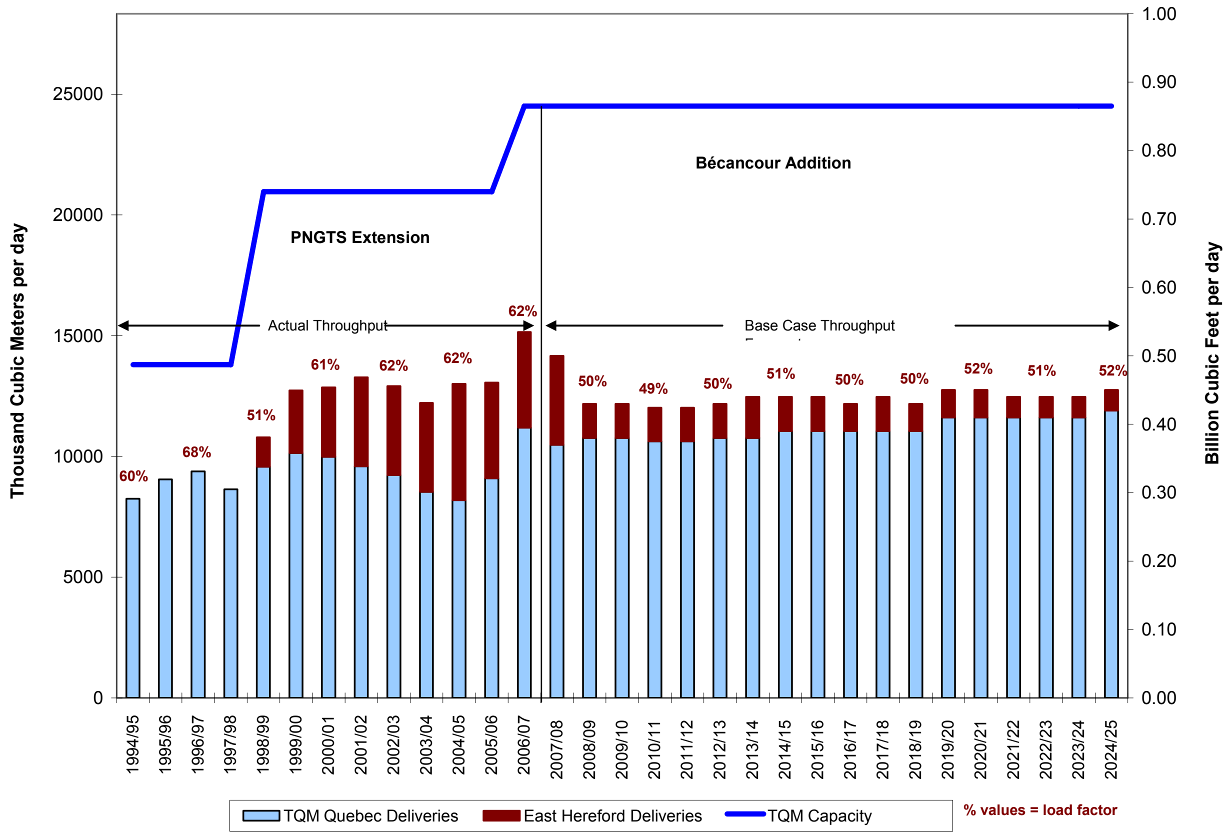
The Board is not persuaded that TQM, by not asking for an increase in its allowed return in 1997, accepted that the market circumstances related to the PNGTS extension did not increase the business risk of the TQM system as a whole. In the Board’s view, a pipeline company should not have to come forward with an application every time that it perceives a change in its risk. Rather a pipeline company can exercise discretion in deciding when to come forward to the Board, knowing that it has no recourse to be retroactively compensated for past changes in risk.

In assessing changes to TQM's business risk, the Board is using TQM's risk at the time of the RH-2-94 proceeding as the point of comparison, which was the last time that the Board fully evaluated it. Consequently, the risk of the PNGTS extension, whether higher or lower than the rest of the TQM system, is treated as a new consideration.

The Board notes that in constructing the PNGTS extension, TQM made a significant investment. The Board is of the view that as time has unfolded, the supply and market situation related to the extension has changed and the risks have increased.

The total gas volume delivered on TQM has grown from 8.22 $10^6m^3/d$ (0.29 Bcf/d) in 1993/94 to 15.01 $10^6m^3/d$ (0.53 Bcf/d) in 2006/07, but the Board does not view TQM’s market to be the same as it was in 1994. A significant portion of the gas deliveries are volumes exported through the PNGTS extension (see Figure 5-2). Capacity of the TQM pipeline system has grown from 13.88 $10^6m^3/d$ (0.49 Bcf/d) in 1993/94 to 24.56 $10^6m^3/d$ (0.867 Bcf/d) in 2006/07, leading to a utilization rate that has increased from 60 per cent to 62 per cent over the same time period (see Figure 5-2). However, it is not expected that TQM will maintain this level of utilization into the future due to competition in the U.S. Northeast.

Figure 5-2
TQM Base Case Domestic and Export Volumes



Source: TQM Application

The Board finds that the Canaport and other U.S. Northeast LNG facilities represent increased competitive risk to PNGTS. The future of LNG imports into the U.S. Northeast has an element of uncertainty due to global competition. However, significant infrastructure related to LNG imports, including an expansion of the M&NE pipeline to deliver gas from Canaport into the U.S. Northeast, is in place or under construction and these facilities represent a competitive alternative to PNGTS in delivering gas into the U.S. Northeast.

Throughput

The Board also finds that the Throughput Study generally supports the case that business risk has increased. The Board is not persuaded by CAPP's view that the appropriate conclusion to be drawn from the study is that risk has not increased because the forecast throughput remains unchanged from 1994. The Board's view is that significant capital costs have been incurred by the Applicant to facilitate the projected throughput and that when this is taken into account the Throughput Study tends to support an increased risk.

Operating Risk

The Board is of the view that there was insufficient evidence provided to conclude that there has been a change in the operating risk faced by TQM.

Regulatory Risk

The Board finds that TQM continues to benefit from its treatment as part of the integrated Mainline. In the Board's view, the risks related to TQM's costs continuing to be recovered principally through their inclusion as "Transportation by Others" on the TransCanada Mainline are the same as in 1994.

The Board is not persuaded by TQM's argument that its business risks have increased because of what TQM characterized as a change in regulatory policy toward more competition between pipelines. The Board is of the same view as expressed in the RH-4-2001 Reasons for Decision when it first examined the Mainline's risks following approval of the Alliance project. At page 27 of the RH-4-2001 Decision, the Board stated that:

> [T]here is nothing to suggest that the Board will alter its approach of considering significant changes to the regulatory framework only on the basis of a comprehensive, balanced and prospective examination of all relevant factors. Although the regulatory regime has permitted increased competition, there has been no indication that it has increased the possibility that prudently incurred costs will not be recovered.

The Board notes TQM's record of earning slightly above its allowed ROE in every year since 1990. The Board finds this history informative but not determinative for evaluating TQM's future risk of experiencing year-to-year earnings fluctuations. It is informative given that TQM indicated that its past deferral coverage was similar to its current coverage, and because TQM continues to be treated as part of the integrated Mainline. Conversely, TQM, for example, may not continue to benefit from its term loan financial charges risk. Overall, the Board finds that TQM's risks related to year-to-year earnings fluctuations are low, and have not appreciably changed.

Conclusion

The Board concludes that TQM's overall business risk has increased relative to 1994, as a result of increased market, supply and competitive risks.

Chapter 6

Interpreting the Return Information from Selected Samples

The selection of companies comparable to TQM is required to draw information that will ultimately be used to determine TQM's cost of capital. The return information, which is drawn from the comparable companies, can be categorized into two groups. The returns of the first group can be referred to as *regulatory* returns, meaning that they are returns allowed or earned on the book value of a regulated asset. This is distinct from the second group, whose returns can be characterized as *financial market* returns, since the return evidence in this group relates to how the stock price of a particular company fluctuates in response to company-specific events as well as events that affect the market as a whole. Investors' expectations are generally recognized to be the main driver of these fluctuations.

The evidence which falls into the first group is detailed in Section 6.2. It includes submissions on the regulatory returns of Canadian pipelines, and some other utilities, as determined by either litigation or negotiation. It also includes TQM experts' submissions on the regulatory returns of U.S. pipelines and local distribution companies (LDCs). Section 6.3 then describes the financial market return submissions related to three samples submitted by TQM experts, and to Dr. Booth's judgements regarding regulated utilities in Canada. The three samples submitted by TQM experts were comprised of Canadian utilities, U.S. Gas LDCs, and U.S. Master Limited Partnerships (MLPs) that own and operate natural gas pipelines (MLP pipelines).

Before addressing these two groups, Section 6.1 presents the submissions which address the relevance of comparisons with U.S. returns. This is a central question to determining the weight to be placed on U.S. returns, which are contained in both groups. Section 6.4 provides the views of the Board on all matters in this chapter.

6.1 Relevance of Comparisons with U.S. Returns

TQM's application relied in large part on U.S. comparisons. This resulted from TQM's submissions regarding both the globalization of capital markets and the similarities between the U.S. and Canadian pipeline and LDC industries. These two topics are addressed in Sections 6.1.1 and 6.1.2, respectively. The reliance on U.S. comparison is also based on TQM's views that Canadian returns suffer from circularity problems and that the companies in Dr. Vilbert's Canadian utilities sample are not pure plays in the natural gas pipeline industry, as will be discussed in Sections 6.2.1 and 6.3.1, respectively.

6.1.1 Integration of Canadian and U.S. Capital Markets

Submissions of TQM

Mr. Murphy, one of TQM's expert witnesses, argued that financial market deregulation supported the free flow of investment capital between countries, capital markets and investment opportunities with the result that comparable financial assets are increasingly priced similarly in different countries. The determination of a fair return is no longer a Canadian market issue; it is becoming a North American and global issue. As a result, Canadian companies like TQM now compete with companies and projects throughout the world for capital.

TQM indicated that the increased integration of capital markets is evidenced by: significant purchase of foreign equities by Canadian investors, including pension funds; the changes in federal tax policies such as the elimination of the foreign property rule in 2005 and the elimination of the withholding tax for cross-border interest payments with the U.S.; and the significant Canadian securities issues outside of Canada with a particular focus on the U.S. TQM also submitted that the increase in cross-border merger and acquisition activities and the increased correlation of global market returns were other evidence of the globalization of financial markets.

In Dr. Vilbert's view, the return available to investors in Canadian utilities must increasingly be comparable to the returns available to investors in comparable risk entities in capital markets worldwide. Accordingly, TQM argued that the Board needs to acknowledge globalization and rely on evidence from the U.S. to determine TQM's cost of capital.

Submissions of Intervenors

According to Spectra and Union, recent market developments made clear the close linkage amongst North American and global markets, and Canada is no exception.

In terms of market integration, Dr. Booth submitted that currencies are freely convertible, investment restrictions have been removed and there has been an increase in the coverage of international stocks among investment advisors. These changes have been mirrored in Canada's international investment position.

According to Dr. Booth, there has been increasing international investment both in and out of Canada since 1990 but the trend since 1990 has been for the U.S. to lose its share of outward Canadian investment. For inward investment, the U.S. remains by far the dominant investor in Canadian stocks and foreign direct investment. Dr. Booth gave evidence that Canadian investors have diversified away significantly from their reliance on the U.S. that was typical in 1990, such that if an external yardstick is relevant today, it is no longer the U.S.

Dr. Booth expressed the view that Canadian markets will always be partially segmented from world markets in general and the U.S. market in particular. The result is a so-called "home bias" where residents of all countries have a disproportionate amount of their wealth invested in their domestic market and look to foreign securities to fill holes in their portfolios. In this context, Canadians are not likely to buy utility or pipeline stocks in foreign markets because the Canadian market has several first tier stocks of these types. Dr. Booth offered the opinion that there is almost no impact of international diversification trends for the utility and pipeline sector's fair ROE except for the tendency for the overall market risk premium to decline.

IGUA argued that the Canadian and U.S. economies and fiscal policies are not the same. In IGUA's submission, the differences have been recently evidenced by the Canadian economy and banking system being less vulnerable in the current credit crisis, as compared with the U.S.

6.1.2 Canadian and U.S. Regulatory Environment

An important question for all comparisons with U.S. pipeline and LDC investments is the extent to which the regulatory environment impacts risk differently in the two countries.

Submissions of TQM

Dr. Carpenter and Mr. Murphy both submitted that U.S. and Canadian transmission pipeline regulation is characterized more by its similarities than differences, and that overall the business risks for pipelines are similar in the two jurisdictions.

In Dr. Carpenter's opinion, the differences between Canadian and U.S. pipeline business risks due to regulation are generally short-term in nature, whereas regulation in the two jurisdictions has fundamentally the same design with regard to factors impacting what he argued were the more important long-term risks. With respect to the latter, Dr. Carpenter contended that unlike the rest of the world, the Canadian and U.S. regimes establish tolls based on the same historical cost rate base and cost of service approach, including a fair return. As additional evidence of similarities, Dr. Carpenter referred to both jurisdictions' use of the contract carrier model, and suggested that both U.S. and Canadian regulators have been actively promoting increased competition between pipelines which increases long-term risk on both sides of the border. Dr. Carpenter also submitted that the typical Canadian regulatory flow-through approach to income taxes results in greater long-term capital recovery risks since the taxes collected as a pipeline ages are typically higher, compared to the normalized approach employed in the U.S.

With respect to short-term risks facing pipelines, Dr. Carpenter indicated that unlike in the U.S. where deferral accounts are typically not used and where toll cases are relatively infrequent, pipelines in Canada generally benefit from annual determinations of their cost of service and have deferral accounts to adjust between forecast and actual revenues and costs in between rate cases. As a result, in his view U.S. pipelines can have more variable year-to-year returns. Dr. Carpenter also contended that there were aspects of U.S. regulation which cause lower short-term risks. He suggested that U.S. pipelines have greater flexibility in charging discounted and negotiated rates which in turn allow them to better respond to increased competition or risk of bypass. Overall, Dr. Carpenter concluded that considering these factors together, in general, U.S. pipelines have greater short-term risks than their Canadian counterparts covered by the RH-2-94 Formula.

Dr. Carpenter also submitted that although the Federal Energy Regulatory Commission (FERC) has accepted settlements in which pipelines shared some costs related to capacity non-renewal, discounting to meet competition, and one-time costs resulting from transition to competition, this is not the FERC's policy. He argued that such settlements are relatively few in number and that ultimately the FERC still allows for the recovery of such costs as they fall in the realm of prudently incurred costs. He submitted that the FERC has explicitly stated that it addresses risk-sharing proposals on a case-by-case basis.

Regarding Dr. Carpenter's evidence comparing the risk exposure of Canadian and U.S. pipelines, Mr. Murphy indicated that it was consistent with his experience as an investment banker. Mr. Murphy observed that pipeline investors view the business risks in Canada and the U.S. as similar. In his view, the regulatory systems are similar, although he too noted many of the same differences submitted by Dr. Carpenter. He also contended that the NEB and FERC have similar policy objectives related to gas pipelines, that capacity charges are common in both countries such that even in the U.S. throughput has limited impact on revenues, and that construction cost incentives are common in both countries and their impact may be counter-cyclical. Additionally, in Mr. Murphy's opinion, TQM specifically, and Canadian pipelines generally, compete directly with U.S. pipelines for load, in what is appropriately characterized as a North American energy market. Mr. Murphy also highlighted his view that on both sides of the border, pipeline investments share the same fundamental long-term, inflexible and capital intensive nature, and are similarly subject to gas supply and competition risks.

Overall, Mr. Murphy was of the opinion that U.S. pipelines may bear higher short-term risks, but that any difference is small given that the duration and amount of additional risk is not significant. He argued that ultimately U.S. pipelines still have the right to return to the FERC with a rate filing if they are not earning their allowed ROE.

Specifically with respect to LDCs, Dr. Carpenter and Mr. Murphy submitted that overall, they tend to be lower risk than transmission pipelines. This is mainly because LDCs are not exposed to as much competition, due to their franchised territories and their mainly residential and commercial customer base which is not at risk of bypass. According to Dr. Carpenter, the FERC found in its 2006 Kern River decision that LDCs are of lower risk than interstate pipelines, and granted a 50 bps upward adjustment to the median ROE from the LDC companies.

In Mr. Murphy's opinion, U.S. LDCs and Canadian pipelines have similar risks because U.S. LDCs recover 100 per cent of their natural gas supply costs, and because their rate designs are increasingly decoupling revenues from volumes. Mr. Murphy also contended that compared with Canadian pipelines, U.S. LDCs have lower supply risk because they source gas supply from multiple pipelines and basins, whereas transmission pipelines are very reliant on a single basin, as is TQM on the WCSB.

Submissions of Intervenors

The CGA argued that while utilities in Canada and the U.S. are not identical, neither are utilities in different provinces identical to federally regulated Canadian utilities. With regard to many of the risks alluded to by CAPP, the CGA argued that they pre-date 1994.

In Dr. Safir's view, there are significant differences between Canadian and U.S. pipeline regulation, and overall Canadian pipelines face considerably less business risk. Dr. Safir was of the opinion that while pipeline regulation in the two countries was almost identical 30 years ago, some fundamental differences have since emerged due to actions taken by regulators, particularly the FERC. Dr. Safir suggested that the FERC has increasingly promoted a more competitive market-driven natural gas pipeline market, and that a key difference today is that rate cases have become infrequent and unnecessary. He took the position that today's U.S. approach is in contrast to the Canadian practice of setting tolls to recover all prudently incurred costs, with the protection of balancing or deferral accounts, and using frequent toll adjustments to keep earnings in line with allowed levels. While U.S. rate hearings can still be requested by either the pipeline or its customers, and can be initiated by the FERC, Dr. Safir submitted that the emphasis has been on negotiated settlements.

In instances when pipeline rate hearings do occur, Dr. Safir contended that the FERC makes few provisions for deferral or balancing accounts, leaving U.S. pipelines at greater risk for annual return variations. In Dr. Safir's submission, as part of the FERC's push towards greater market signals, it has made it clear that revenue shortfalls resulting from uncontracted capacity have to be shared by the pipeline. He noted that with this has come the ability for pipelines to negotiate for shares of the upside, when revenues are increased due to higher throughput. CAPP argued that volumetric risk is simply a part of the FERC model.

In Dr. Safir's opinion, the U.S. practice of very infrequent rate hearings means that U.S. pipelines are exposed to a high probability that significant differences will emerge between allowed and achieved earnings. Additionally, he submitted that earnings variability results from the prevalence of discounted and negotiated rates in the U.S. Dr. Safir put forward an analysis comparing the difference between actual and allowed ROEs for Canadian and U.S. pipeline companies. The results, in his submission, showed a tighter distribution of actual minus allowed earnings for Canadian pipelines, exactly as one would expect if Canadian regulation results in lower business risks than the U.S. equivalent.

Dr. Safir also suggested that additional differences are perceived by the market between U.S. and Canadian pipeline risks, citing as an example the move away from the merchant gas function for pipelines in both countries. He observed that this restructuring process resulted in real losses for U.S. pipelines, unlike their Canadian counterparts.

With respect to U.S. LDCs, Dr. Safir submitted that they are subject to a range of different state regulations, none of which provide the degree of protection afforded to NEB regulated pipelines. He provided another analysis comparing actual ROEs minus allowed ROEs of Canadian pipelines, in this case, to those of U.S. LDCs. Dr. Safir was of the opinion that the lower variability of the Canadian pipelines demonstrated that U.S. LDCs would not be a very good comparator group for TQM. He also suggested that since 1994, the risks faced by U.S. LDCs have come down to some extent, because of some regulatory changes.

Regarding the FERC's view of LDC risks, Dr. Safir contended that the FERC had determined that LDCs are not appropriate comparators for U.S. pipelines. In support of this, he submitted the same FERC Kern River decision cited by Dr. Carpenter, but he reached a different conclusion on the matter.[30] Dr. Booth was of the opinion that LDCs in general, not just in the U.S., are higher risk than pipelines.

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30 The following excerpts from the FERC decision discuss the issue in question (FERC OPINION NO. 486, issued October 19, 2006):

> 2. … The median return of our revised proxy group is 10.7 percent. In addition, because this proxy group is small and includes companies with a relatively low proportion of pipeline business and substantial distribution operations, we approve a 50 basis point adjustment above the median to 11.2 percent. This accounts for differences in risk between Kern River and the proxy group companies. [emphasis added]
>
> 171. … We will therefore permit an adjustment above the median of the range to account for differences in risk between the pipeline and proxy group companies whose LDC operations account for a greater proportion of their business than previously occurred under our traditional policy.
>
> 172. The evidence in this case is undisputed that the risk profile of LDCs is different from the risk profile of typical interstate pipelines. No party disagrees that LDCs face lower risks due to the nature of their operations. As Kern River's witness testified, LDCs enjoy a natural service monopoly, with relatively low demand elasticity, price sensitivity and throughput risks. The franchise structure of an LDC results in lower overall business risk and lower investor expectations. In contrast, gas pipelines are one level removed from the end-use markets served by LDCs and retail utilities and enjoy no such service monopoly or territorial franchise [footnote removed].

CAPP argued that the U.S. regulatory approach is anything but safe for a utility, noting some utility bankruptcies which have occurred. CAPP noted Dr. Kolbe's past articles and text books which discuss U.S. regulatory risks, particularly related to the restructuring to end the merchant gas function for pipelines and the Duquesne instance of cost disallowance in a partial nuclear plant build.[31] CAPP also argued that comments that were made by Moody's Investor Services (Moody's) about the supportive nature of Canadian regulation and the Canadian business environment demonstrate the lower regulatory risks in Canada.

Another factor which CAPP argued lowers Canadian pipeline risks is the NEB approach to pre-approving projects before investments are made. CAPP argued that the Duquesne partial nuclear build, where costs were not ultimately allowed to be recovered, demonstrates the benefit of the NEB approach, and that today, significant efforts by U.S. project proponents are dedicated in the early phases towards avoiding eventual cost disallowances similar to those experienced by Duquesne Light Co.

With regard to U.S. LDCs, CAPP questioned why TransCanada Corporation had different views in front of the FERC regarding the comparability of pipeline and LDC returns, as compared with what was submitted to the NEB by TQM with TransCanada's support. CAPP argued that there are some fundamental parameters of regulation that are not the same across regulators, arguing that for example there is no uniform approach to rate base at the state level in the U.S. According to CAPP Counsel, when looking at a number of state decisions, one sees strange tradeoffs, for example where utilities make significant concessions in order to gain regulatory acceptance of proposals. Finally, CAPP argued that there is an ongoing debate regarding decoupling mechanisms, about such issues as whether they in fact reduce risk and what exactly is or is not a decoupling mechanism.

Overall, CAPP suggested that the significant differences between the U.S. and Canadian regulatory systems imply that U.S. pipelines and LDCs are poor comparators for TQM, with Dr. Safir emphasizing any comparison would have to be on a risk adjusted basis.

In the opinion of Ontario, U.S. pipelines are not appropriate comparators for Canadian pipelines because of significant regulatory differences, and because U.S. pipelines face higher financial liability risks.

IGUA submitted that U.S. LDCs and pipelines operate within a very different regulatory framework, implying very different regulatory risks. IGUA also argued that the U.S. and Canadian economies and fiscal policies are different.

TQM's Reply

In Dr. Carpenter's submission, the effects of the four FERC Orders, which Dr. Safir argued had substantially changed U.S. natural gas pipeline regulation, were primarily to end the merchant

31 "The Duquesne instance" refers to the case where Duquesne Light Co. cancelled plans to build nuclear power plants, and then sought regulatory approval to recover the capital it had already invested. The Pennsylvania Public Utility Commission approved the amortization of the cancelled plants, but the state legislature passed a law which the effect of disallowing the recovery of those costs. The case was ultimately decided by the U.S. Supreme Court Decision in *Duquesne Light Co. v. Barasch,* 488 U.S. 299 (1989), and the costs in question were not allowed to be recovered by Duquesne Light Co.

gas function of pipelines. Dr. Carpenter noted that similar changes occurred in Canada, and additionally that all four FERC orders pre-dated 1994 which he argued meant that they would not explain any change in relative Canadian and U.S. risks since 1994. With respect to the differences in the frequency of rate hearings and use of deferral accounts cited by Dr. Safir, Dr. Carpenter put forward that they were consistent with his own evidence related to higher U.S. short-term risks.

As discussed in Section 5.6, Dr. Carpenter also argued that Dr. Safir's comparison of actual ROEs minus allowed ROEs was flawed both conceptually and at a computational level.

With regard to the losses experienced by U.S. pipelines as a result of the restructuring process to end pipelines' merchant function, and the nuclear build cost disallowances discussed, Mr. Murphy suggested that these were two of the most difficult periods in the history of the U.S. utility industry and were one-time events. He contended that such events are not reflective of how things normally unfold. TQM suggested that subsequent electricity deregulation efforts may have been evidence of regulators having learned from the gas merchant pipeline restructuring.

On the question of Moody's view of the supportive nature of Canadian regulation, TQM acknowledged that the Canadian regulatory environment is viewed as very supportive by both Standard & Poor’s (S&P) and Moody's. However, as discussed in Section 5.1, TransCanada suggested that rating agencies have a very different perspective than equity holders.

Mr. Murphy submitted that regardless of the legal question of whether or not a utility needs prior pre-approval to build a project, as with NEB regulated pipelines, in reality plenty of work is done in advance of any build such that it is a collaborative process where regulators and outside stakeholders are generally involved at an early phase. TQM emphasized that the important question is not the legal requirements, but what an investor can reasonably expect in terms of the practical risks.

With regard to TransCanada Corporation's submission to the FERC regarding the appropriate composition of a proxy group for pipelines, TransCanada submitted that the context of the FERC's inquiry was that it had been using a proxy group composed primarily of LDCs during a period of time where a growing number of MLPs were forming with concentrated interstate pipeline holdings. In that context, TransCanada suggested that TransCanada Corporation's position was that the MLPs represented a better alternative. With regard to TransCanada Corporation's expressed concern regarding the circularity of LDC returns, TransCanada stated that the concern is only of a closed system, such as a regulator looking only at its own rulings.

Regarding the question of whether rate base is treated in a consistent manner across states, Mr. Engen, on behalf of TQM, submitted the debate had been regarding whether rate base should be calculated on a fair market- or book-value basis, but that the debate had been put to bed in favour of the book-value approach.

6.2 Regulatory Return Evidence

6.2.1 Canadian Negotiated Returns

Submissions of TQM

TQM submitted that total returns derived from negotiated settlements should be used as part of a comparative analysis. TQM recommended making these comparisons on an aggregate rather than individual basis, since individual settlements contain tradeoffs that are unknown to those not involved in the negotiating process, tradeoffs which may result in returns above or below what would have otherwise been agreed to. Looking at settlements in aggregate, in TQM's submission, provides a directional indication of market expectations for acceptable returns, and avoids the risk that any one settlement might be providing returns that are reflective of very particular unknown circumstances or tradeoffs. In response to information requests and hearing questions, TQM also submitted that settlements may result in an exchange of value which may be over and above that available under traditional cost of service regulation, and that parties may agree to increased returns without a commensurate increase in risk.

TQM suggested that the Board should give greater weight to Canadian pipeline returns derived from settlements than to NEB-adjudicated returns to avoid circularity in approving returns, but cautioned that even settled returns may be below market levels because they are negotiated against the backdrop of the below-market-level RH-2-94 Formula.

On these grounds, TQM submitted evidence on the returns derived from a number of NEB-regulated pipeline settlements. Notably, all of the Canadian pipelines which TQM submitted as comparables had their returns determined in part or wholly by settlements. TQM suggested that the returns determined wholly by settlements consistently yielded returns in excess of those provided by the RH-2-94 Formula. TQM submitted that it could not describe the tradeoffs made in any of the individual settlements since it had not been party to the negotiations. However, TQM provided a comparative business risk analysis for the subject pipelines, and concluded that all of them had business risks that were similar to or lower than TQM's. To support this finding with respect to the oil pipelines in its comparator groups, TQM suggested a number of factors, explained further in Section 6.3.1.1, that should lead the Board to no longer hold the view that oil pipelines are riskier than gas pipelines, a view it articulated as recently as the RH-2-2004, Phase II Decision.[32]

Submissions of Intervenors

The CGA argued that settlements can be informative at the aggregate level, and that the Board can exercise its judgement in assessing the relative risks at that aggregate level.

In CAPP's view, the higher returns observed in negotiated settlements are a result of pipelines moving away from the traditional cost of service model and being rewarded for creating additional value or benefits for toll payers. CAPP emphasized that settlements are package deals and involve tradeoffs, and noted that the Board has recognized this in the past. A further point advanced by CAPP was that settlements are negotiated in confidence and typically expressly

32 RH-2-2004, Phase II Reasons for Decision, *supra*, footnote 8, at p. 7.

state that parties agree that a settlement is without prejudice and is not to be used as precedent. As a signatory to the settlements cited by TQM, CAPP argued that it is unfair that it had a limited ability to respond.

CAPP's position was that the Board would have to be very cautious in putting any weight on the information from settlements, and that a better approach would be to give them no weight. If the Board were to instead put weight on Canadian settlement evidence, CAPP put forward that there could be a chilling effect on future settlements.

Dr. Safir submitted that negotiated returns are determined through a different process than litigated returns. In his view, settlements do not have to reflect any of the same factors looked at by regulators, and that parties can trade off other factors against a negotiated return. He suggested that parties to settlements work cooperatively to enhance the benefits and values for all, which could influence agreed-to returns.

IGUA recommended that the Board give no weight to settlement returns. IGUA argued that it is not possible to identify the tradeoffs made in arriving at a final outcome, and noted that the Board accepts or rejects any settlement as a package. In IGUA's view, it would be inappropriate to, after the fact, isolate the return component. IGUA also warned that doing so would have a chilling effect on future settlement prospects.

Ontario argued that settlements contain unknown tradeoffs, and so the Board should not consider settlement returns.

6.2.2 Canadian Litigated Returns

Submissions of TQM

TQM argued that Canadian provincial regulators appear to follow the NEB's lead in setting returns and using ROE formulas. In TQM's view, this makes Canadian comparisons of limited relevance if not circular. TQM excluded from its comparisons a number of Canadian pipelines and utilities on the basis that their returns were set by either the NEB or provincial ROE formulas and thus suffered from circularity.

Submissions of Intervenors

CAPP submitted that the ROE formulas across Canada were not adopted in a mechanical way, and noted that there have been many hearings involved both with establishing and reviewing the formulas. According to CAPP, in each hearing there was a full and fair consideration of the evidence.

Dr. Booth noted that the NEB was not the first regulator to adopt an ROE formula. He suggested that while there is a degree of circularity in looking at returns awarded by other regulators, each regulator has heard different evidence from different experts, at various times, and ultimately reached its own conclusions. He advised that the awards of other regulators are appropriately used as a reasonableness check.

Evidence put forward by Dr. Booth compared the allowed returns for various Canadian pipelines and utilities, including from Quebec, Ontario, Alberta, and British Columbia. Dr. Booth recommended that TQM's equity ratio be increased to 32 per cent because he argued that the EUB had increased the "floor" for utility equity thickness to 32-33 per cent.

6.2.3 Litigated U.S. Returns

Submissions of TQM

Dr. Carpenter submitted a comparison between the allowed returns of TQM and those allowed to U.S. interstate pipelines and LDCs in litigated proceedings. As noted previously, in Dr. Carpenter's opinion, achieved-earnings data are fundamentally flawed because they rely on accounting data and are based on past, not future circumstances. In his comparison of allowed returns, Dr. Carpenter submitted two alternative measures of allowed returns: (i) ROE alone; and (ii) an ATWACC return that results from the allowed ROE and capital structure combined with an assumed after-tax cost of debt for all companies in all years of 3.75 per cent.

In Dr. Carpenter's view, the current gap between the allowed returns of TQM and the U.S. comparables is not justified by differences in risk, and since 1994 there has been an unjustified divergence between the allowed ROE of TQM and the U.S. comparables. TQM argued that this divergence is not justified by any changes in relative business risks.

Mr. Murphy also provided litigated allowed returns data for both U.S. interstate pipelines and LDCs. For transmission pipelines, he submitted that his sample showed that U.S. allowed ROEs and equity thickness were both higher. In the case of LDCs, Mr. Murphy divided them into two groups depending on whether their rates featured what he referred to as revenue decoupling or weather normalization, respectively. He submitted that both groups had allowed ROEs significantly above the current RH-2-94 level.

Submissions of Intervenors

The CGA also argued that since 1994 a gap has grown between U.S. and Canadian allowed returns for utilities, a gap not justified by any changes in relative business risks.

CAPP, IGUA and Ontario all took the position that the higher U.S. allowed returns are appropriate based on their higher risks. These views are discussed in Section 6.1.2, under the heading *Canadian and U.S. regulatory environment*.

With respect to Dr. Carpenter's analysis of the allowed returns of U.S. interstate pipelines, Dr. Safir suggested that there were too few data points to conclude that there has been a systematic increase in the difference between TQM's allowed returns and the average allowed to the interstate pipelines.

6.3 Financial Market Returns Evidence

The following Section is a description of the three samples submitted by Dr. Vilbert as well as Dr. Booth's submission, Section 6.3.2 addresses the potential that the computed costs of capital might be affected by unregulated business activities.

6.3.1 Description of Samples

Table 6-1 summarizes the information drawn from the samples presented in evidence that were used by TQM and CAPP to derive their respective recommendation as to what return TQM should be allowed. The table partly reflects the following techniques which the Board determined it would rely upon in Chapter 4.

- The costs of equity (Lines 1 to 5), as derived by CAPM, rely on unadjusted betas and the respective risk-free rate and market risk premium suggested by Dr. Vilbert and Dr. Booth.
- Lines 1 to 3 rely on the market-value capital structure, market cost of debt (ranging from 5.4 per cent to 5.9 per cent) and assume the presence of preferred shares, if any, in the capital structure of the sample companies.
- Line 4 uses the same parameters as Line 1 except it uses Dr. Booth's cost of equity estimate.
- Line 5 is Dr. Booth's recommendation based on his assessment of TQM's business risk and TQM's weighted average of embedded cost of debt of 6.07 per cent for 2008, at 32 per cent equity thickness.

Table 6-1
Cost of Capital Derived from Expert Witness Evidence

Source	Description	Cost of Equity (Per cent)	Equity Thickness (Per cent)	ATWACC (Per cent)
TQM Evidence (Dr. Vilbert)	1. Canadian utilities	7.4*	51	5.7*
	2. Gas LDC	9.2	60	7.0
	3. MLP Pipelines	7.4	68	6.3
CAPP's Evidence (Dr. Booth)	4. Dr. Booth recommendation under a market-based ATWACC methodology	7.75	51	5.9*
	5. Dr. Booth recommendation	7.75	32	5.3*

* As computed by the Board

Submissions of TQM

Dr. Vilbert submitted that there is no ideal sample of publicly traded pure play Canadian natural gas transmission companies available. He submitted evidence for three samples: the Canadian utilities sample, the Gas LDC sample and the MLP pipelines sample. In determining the cost of equity of the sample companies, Dr. Vilbert used a risk-free rate of 5.0 per cent, which includes a

20 basis point maturity premium. This estimate was based on the Consensus Forecast issue of August 2007. Dr. Vilbert also used a market risk premium of 5.75 per cent based on his estimate of the long-term risk-free rate and current information on the historical market risk premium.

6.3.1.1 Canadian Utilities

Submissions of TQM

Dr. Vilbert submitted that the goal of his Canadian utilities sample is to represent companies whose primary business is as a regulated utility in Canada with business risk generally similar to that of TQM. Dr. Vilbert started with the universe of Canadian companies classified as being in the utility industry or in the oil and gas storage and transportation industry in the FPinfomart database. Companies were eliminated by Dr. Vilbert that were not listed in the FP500 Sales category on FPinfomart. This step eliminated a number of smaller companies that do not trade on the Toronto Stock Exchange. Dr. Vilbert subsequently applied additional selection criteria design to narrow the sample to companies with characteristics similar to that of TQM. The final sample resulted in the following five companies: Canadian Utilities, Enbridge Inc., TransCanada Corp., Emera Inc. and Fortis Inc. Despite the selection criteria used, Dr. Vilbert noted that several of these companies have non-regulated activities and assets, and have recently been engaged in acquisition activities. As indicated by Dr. Kolbe, the Canadian utilities sample is smaller than in the RH-2-2004, Phase II proceeding and small samples have larger measurement errors. For these reasons, Dr. Vilbert was of the view that additional samples were necessary to provide a more reliable estimate of TQM's cost of capital.

One issue of particular relevance to the Canadian utilities sample is that it contains Enbridge Inc., which has significant interests in oil pipelines. TQM noted that the Board has in the past regarded oil pipelines as having higher risk than gas pipelines, but submitted that a number of changes have caused the risks faced by oil and gas pipelines to become more similar, and that TQM's business risks are now comparable to those of Enbridge Pipelines Inc. (Enbridge). TQM submitted that new oil pipelines and expansions of existing oil pipelines are increasingly being underpinned by long-term contracts while the contract lengths on gas pipelines including TQM have been declining, such that the traditional differences in risk caused by the contract versus common carriage distinction have been diminished. TQM also submitted that Enbridge and Trans Mountain Pipe Line Company Ltd. (Trans Mountain) were traditionally exposed to greater earnings variations than is the case under their current settlement-based toll methodologies. In response to the Board's statement in RH-2-2004, Phase II regarding the "operational complexities arising from the multiproduct nature" of oil pipelines,[33] TQM submitted that in its view both Enbridge and Trans Mountain have tariff protections against costs related to such complexities. Finally, TQM submitted that there has been a divergence in the supply outlook for oil and gas, such that gas pipelines now face greater supply risk than oil pipelines. Mr. Engen submitted that the financial markets distinguish between oil and gas pipelines based primarily on supply risk, and hence now view oil pipelines as being less risky overall than gas pipelines.

33 RH-2-2004, Phase II Reasons for Decision, *supra*, footnote 8, at p. 68.

Submissions of Intervenors

In Ontario's submission, the circumstances which led the Board to view oil pipelines as riskier than gas pipelines in the RH-2-2004, Phase II Reasons for Decision remain unchanged. Namely, Ontario was of the view that: despite TQM's declining contract length, gas pipelines have long-term contracts, whereas oil pipelines remain common carriers supported only by monthly nominations; oil pipelines are exposed to operational risks because of their multi-product mix, and Enbridge's history of protection against these risks does not guarantee the same going forward; and oil pipelines operate under settlements which were negotiated with different financial parameters. Therefore, Ontario submitted that oil pipelines are intrinsically higher risk than, and inappropriate comparators for, gas pipelines.

6.3.1.2 Gas LDC

Submissions of TQM

Unlike the Canadian utilities sample, Dr. Vilbert stated that all companies in the Gas LDC sample have operations concentrated in the natural gas industry. In selecting the Gas LDC sample, Dr. Vilbert started with the universe of publicly traded natural gas distribution utilities covered by *Value Line Investment Survey Plus Edition*. Vectren Corporation was added to the initial group because, as Dr. Vilbert mentioned, it is often viewed as a natural Gas LDC. Companies with unique circumstances which may bias the cost of capital estimates were eliminated and Dr. Vilbert submitted a final sample comprising the following ten companies with the fewest reliability concerns: AGL Resources Inc., Atmos Energy Corp., The Laclede Group, New Jersey Resources, Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, Southwest Gas Corp., Vectren Corp., and WGL Holdings Inc. Dr. Vilbert also considered a sub-sample with the fewest reliability concerns. All companies from this sample were from the U.S.

Dr. Carpenter submitted an assessment of the companies in Dr. Vilbert's LDC sample. He argued that they were relatively pure play LDCs, as described further below, and concluded based on their individual characteristics that their long-term risks were lower than TQM's. He submitted that TQM had lower short-term risks, though all the sample LDCs had weather normalization mechanisms and all but one had additional rate mechanisms to partially protect them from revenue loss related to certain volumes. Overall, Dr. Carpenter argued that the long-term risk differences outweighed the short-term differences, such that TQM's overall risk was higher than the companies in Dr. Vilbert's Gas LDC sample.

6.3.1.3 MLP Pipelines

Submissions of TQM

The MLP pipelines sample was selected by Dr. Vilbert by searching Dividend Detective and the Publicly Traded Partnerships website. Dr. Vilbert retained companies owning pipelines and having investment grade bond ratings. Companies with significant mergers and acquisition activities and having experienced distribution cuts were subsequently eliminated by Dr. Vilbert. The MLP pipelines sample was comprised of the remaining six companies: Boardwalk Pipeline Partners, Kinder Morgan Energy Partners, TC Pipelines, Oneok Partners, Enbridge Energy Partners and Enterprise Products Partners; none of these strictly being oil companies. According to Dr. Vilbert, the MLP pipelines sample is the closest to a pure play natural gas pipeline sample currently available, and the universe of MLP pipeline companies is growing. Dr. Vilbert noted that MLPs in this sample operate on a national scale in the U.S. with pipelines crossing many states. Dr. Vilbert was of the view that cost of capital estimates from this sample are conservative because of the difficulty of estimating the market value of the General Partner (GP) share of the equity.

6.3.1.4 Dr. Booth's Estimate

Submissions of Intervenors

Dr. Booth did not rely on a specific sample of comparables to derive his cost of equity recommendation. Dr. Booth relied on the historical performance and behaviour of major utility holding companies and pure play utilities in Canada. Dr. Booth also relied on TSX/S&P Composite sub-indexes of Gas/Electric, Telco, Pipes and Utilities. Based on his professional judgment, a CAPM estimation and a two-factor model, Dr. Booth expressed the view that a "typical regulated utility" should be allowed an ROE of 7.75 per cent.

In estimating the cost of equity with CAPM, Dr. Booth used a risk-free rate of 4.75 per cent based on the Consensus Economics forecast and the 30-10 year spread. Dr. Booth also relied on a 5.0 per cent market risk premium based on the influence of earlier data, the recent unexpected performance of the bond market and a reduction in the risk on the bond market compared to a few years ago. Dr. Booth's cost of equity estimate includes a 50 basis point allowance for floatation costs.

6.3.2 Unregulated Activities in Market Data from Selected Samples

To the extent that the companies in the selected samples are engaged in both regulated and unregulated business activities, in addition to comparing the risks of their regulated activities with TQM's, it is also important to determine if and the extent to which their unregulated business activities could be expected to influence the estimated costs of capital.

Submissions of TQM

Dr. Carpenter submitted evidence on the degree of unregulated business activities of the companies in Dr. Vilbert's LDC sample, as well as for some of the MLPs in Dr. Vilbert's MLP pipelines sample, based on measures of both earning and asset shares. Dr. Carpenter judged the LDC sample to be a relatively "pure play" LDC sample based on two factors. First, he submitted that for 2006 the sample LDC companies each earned between 50 and 99 per cent of their net income from regulated gas distribution, transportation and storage services, and had 66 to 100 per cent of their assets committed to these regulated activities. Second, in Dr. Carpenter's opinion, his evidence showed that for the most part, the competitive transportation and storage services were insignificant parts of the companies' overall activities. Dr. Carpenter's evidence suggested that the non-regulated activities varied in nature, ranging for example, from natural gas marketing to power plant ownership.

With respect to Dr. Vilbert's MLP pipelines sample, Dr. Carpenter examined the business activities of the three MLPs that in his view were the most heavily involved in interstate natural gas transmission and storage, namely Boardwalk Pipeline Partners, LP; Oneok Partners LP; and TransCanada Pipelines, LP. Based on his evidence for up to five recent years, these MLPs earned between 59.2 and 100 per cent of their net revenues from interstate natural gas transmission and storage, while 80 to 100 per cent of their plant, property and equipment was invested in these same activities.

Dr. Vilbert attempted to control for the potential impact of unregulated activities in his cost of capital estimations by selecting sample companies with the highest levels of regulated assets. He suggested that non-regulated activities are in general expected to be somewhat higher risk than regulated activities, but argued that risk measures and estimated cost of capital may not reflect this expectation, for example because of estimation errors. He indicated that he does not know how large an adjustment, if any, should be made on the basis of sample companies' unregulated activities. Dr. Kolbe also suggested that a factor which could offset any potential bias in estimated costs of capital from the presence of unregulated business activities is that in cases where the unregulated businesses are experiencing difficulties, their measured cost of capital will tend to underestimate their true cost of capital.

In Dr. Vander Weide's submission, there are no adequate measures to delineate regulated from unregulated activities, mainly because of distortions in accounting measures and limited availability, in practice, of information which is fully segregated between regulated and unregulated activities. He also argued that unregulated activities are not necessarily higher risk than a low risk pipeline.

In response to a CAPP IR, TQM provided a Dominion Bond Rating Service (DBRS) report describing its utilities ratings methodology. In a section titled "Non-Regulated Activities", DBRS stated:

> given the higher business risk inherent in non-regulated activities, companies with larger exposures to non-regulated activities would be expected to have lower financial risk (i.e., lower balance sheet leverage and higher fixed charges coverage ratios) as a compensating factor in order to have a comparable credit rating.[34]

Similar methodology reports from the other major bond rating agencies were less explicit on this point.

Views of the Board

Integration of Canadian and U.S. Capital Markets

In the Board’s view, global financial markets have evolved significantly since 1994. Canada has witnessed increased flows of capital and implemented tax policy changes that facilitate these flows. As a result, the

34 DBRS Rating Approaches -- Rating Utilities (Electric, Pipelines & Gas Distribution) at p. 2.

Board is of the view that Canadian firms are increasingly competing for capital on a global basis. The Board notes that Canada has been diversifying its business partners such that there is currently proportionally less Canadian foreign direct investment in the United States than there was in the 1990's. Nonetheless, the evidence is also clear that the United States is the single most important recipient of Canadian investments.

A fair return on capital should, among other things, be comparable to the return available from the application of the invested capital to other enterprises of like risk and permit incremental capital to be attracted to the regulated company on reasonable terms and conditions. TQM needs to compete for capital in the global market place. The Board has to ensure that TQM is allowed a return that enables TQM to do so. Comparisons to returns in other countries would be useful, but challenging, in terms of differences in business risks and business environment. As a result, the Board is of the view that pipeline companies operating in the U.S. have the potential to act as a useful proxy for the investment opportunities available in the global market place.

Canadian and U.S. regulatory environment - Transmission Pipelines

The Board is not persuaded that the U.S. regulatory system exposes utilities to notable risks of major losses due either to unusual events or cost disallowances. The Board views the losses and disallowances experienced by U.S. regulated entities as a result of the restructuring that took place to terminate the merchant gas function of pipelines, as well as some other circumstances such as the Duquesne nuclear build, to be, to a large extent, unique events. The Board also finds that such instances are not likely to weigh significantly in investors' perceptions today, and would thus have little or no impact on cost of capital.

The Board is of the view that volumetric risk is more a feature of the U.S. regulatory model than the Canadian one. However, the Board did not find that the evidence supported the conclusion that volumetric risk impacts long-term risks of capital recovery. The Board finds that volumetric risk clearly impacts short-term risks of allowed earnings not being achieved, and sometimes for consecutive years between rate cases. The Board also finds it significant that volumetric risk has a symmetric nature, presenting pipelines with some counteracting upside opportunities.

The Board notes that Dr. Safir's evidence points to greater variability in the actual earnings minus allowed earnings of U.S. pipelines compared with Canadian ones. Dr. Carpenter submitted that this is consistent with his view that U.S. short-term risks are higher. The Board agrees with this view and finds that the short-term risks faced by U.S. pipelines are higher than those borne by TQM specifically and by their Canadian counterparts generally.

Overall, the Board finds that the risks resulting from the regulatory environment are higher for U.S. pipelines than for Canadian pipelines, and finds that this was also true in 1994. However, the Board is of the view that the risks faced by TQM and those faced by U.S. pipelines are not so different as to make them inappropriate comparators. The Board accepts that there are many similarities between the risks faced by pipelines in the two countries. This is due to the two regulatory models sharing, to a large extent, the same fundamental principles. Moreover, Canadian and U.S. pipelines operate in what the Board views as an integrated North American natural gas market, which informs the choices made by regulators in the different jurisdictions.

Canadian and U.S. regulatory environment - LDCs

The Board notes that Dr. Safir's evidence suggested that the short-term earnings variation of U.S. LDCs was higher than that of Canadian pipelines, although lower than U.S. pipelines. The Board also notes that Dr. Carpenter submitted that TQM had lower short-term risks than the companies in Dr. Vilbert's LDC sample. The Board concurs that U.S. LDCs have higher short-term risks than TQM.

On the question of Dr. Safir's and Dr. Carpenter's divergent views on what the FERC found with respect to the relative risks and comparability of U.S. interstate pipelines and LDCs, based on the Board's consideration of the FERC decision presented in evidence, most notably the excerpts provided in the footnote in Section 6.1.2, the Board accepts Dr. Carpenter's submission that the FERC accepted companies with high proportions of LDC operations in the proxy group and adjusted their returns upward by 50 bps, having judged LDCs to have lower risks than interstate pipelines. The Board is informed by the FERC's view on this matter.

The Board notes that there was no evidence showing that LDCs have higher long-term risks than transmission pipelines. However, there were views suggesting the opposite due to the nature of LDCs' market and supply risks. The Board is of the view that the evidence did not support a clear finding on the relative long-term risks of TQM versus U.S. LDCs.

The Board is satisfied that the evidence establishes that TQM and U.S. LDCs are sufficiently similar in risk so as to make comparisons meaningful. In assessing the comparability of U.S. LDC returns, the Board's view regarding the higher short-term risks of U.S. LDCs meant that, overall, the Board viewed the regulated LDC activities of this group as somewhat higher risk than TQM. The Board would have benefited from additional information on the comparability of this group with TQM.

Canadian Negotiated Returns

The Board's policy is to approve or reject settlements as a whole, recognizing that there are unknown tradeoffs made in arriving at what ultimately comes to the Board as a package deal. When the Board finds that the resulting tolls would be just and reasonable, the Board does not approve each component as just and reasonable on a standalone basis. The Board is of the view that the evidence in this proceeding has highlighted the fact that negotiated tradeoffs cannot be observed or deduced by outside parties, and that any one aspect of a settlement, including the allowed return, cannot be presumed to have been independently acceptable to parties.

The Board is not persuaded that looking at a number of settlements in aggregate alleviates this fundamental problem. The Board finds that the uncertainty related to the tradeoffs is a great barrier to the informative value of settlement returns. Therefore, the Board has placed no weight on the returns derived from Canadian negotiated settlements.

Canadian Litigated Returns

On the question of whether litigated Canadian utility returns are similar because of problems of circularity, or whether they provide a valid signal because they represent independent conclusions reached on similar questions, the Board finds that there was no evidence that conclusively supported either view. Faced with contrasting opinions on the matter, and with the option of relying on returns from other submitted comparables, the Board placed no weight on Canadian litigated returns.

Litigated U.S. Returns

As detailed more fully in other Sections, the Board has placed principal weight on the market-based return data. Nonetheless, the Board found that litigated U.S. returns were useful as a check against the results from the analyses which relied upon market returns.

Financial Market Data Results from Selected Samples

In determining what weight to assign the Canadian utilities sample, the Board considered the relevance of the factors which led it to place no weight on Canadian negotiated and litigated returns. The Board finds that financial market data results, properly derived, yield estimates of sample companies' true underlying costs of capital. This is because, in the Board's view, the underlying cost of capital is driven by investors’ expectations as expressed in financial markets, and allowed returns are only one of many factors influencing these expectations. As a result, the Board finds that market-based estimates of cost of capital largely circumvent the problems which the Board found to be associated with direct comparisons to Canadian negotiated and litigated returns.

The Board also considered whether the risks faced by companies in the Canadian utilities sample have changed, relative to TQM's, as a result of some of their business segments being governed by negotiated settlements. In the Board's view, the evidence did not establish that settlements, at an aggregate level, have caused either a systematic increase or decrease in business risks. As a result, the Board compared TQM with the companies in the Canadian utilities sample based on other underlying business risk considerations, such as supply, market and competitive risks

In considering the Canadian utilities sample's inclusion of Enbridge Inc., the Board finds TQM's submission regarding the changes that influence the relative risks of oil and gas pipelines to be persuasive in suggesting that the relative risks of oil and gas pipelines have directionally come together. However, the Board did not find that TQM established that its risks, nor those of gas pipelines generally, are today at the same level or higher than those of oil pipelines. Given the Board's view that the relative risks have become more similar over time, and the fact that Enbridge Inc. also has interests beyond oil pipelines, the Board finds it acceptable to include Enbridge Inc. in this sample.

Given these views related to the Canadian utilities sample, and because in the Board's view the sample companies operate in a similar environment (regulatory, financial and political) as TQM, the Board found the Canadian utilities sample helpful.

Dr. Booth's cost of equity estimate of a "typical regulated utility", as shown in Table 6-1, was of assistance to the Board in its interpretation of the ATWACC results. The Board recognizes some limitations in combining this cost of equity estimate with market-value capital structure since the capital structure might not perfectly match the one of a "typical regulated utility" in Canada. Nevertheless, the Board is of the view that Dr. Booth's evidence regarding a "typical regulated utility" can reasonably be representative of the utility industry in Canada, an industry of which TQM is a part. However, the Board views TQM as being part of a larger business environment than one delineated by the Canadian border.

The Board accepts that TQM can be compared to some degree with the Gas LDC sample since the operations of the sample companies are concentrated in the natural gas business and the differences in respective business environments can, in the Board's view, be reasonably understood and accounted for.

The Board found the MLP pipelines sample informative as it was presented as a sample being the closest to a pure play natural gas pipeline sample currently available. In the Board’s view, the higher short-term business risks of U.S. pipelines, which the MLP pipelines sample is subject to, can be offset to some degree by what the Applicant submitted was an underestimation of the MLP equity value due to the difficulty of estimating the market value of the GP. Since the MLP pipelines sample seems to be a promising sample for future proceedings, the Board is of the view that it would benefit from a thorough examination of the General Partner/Limited Partner relationship.

Unregulated Activities in Market Data from Selected Samples

In principle, the Board does not believe that comparables necessarily need to be all, or mostly, regulated. Rather, the important question is how comparable the risks are. If there were completely non-regulated companies with risks that were similar to a pipeline's, or if risk differences could be accounted for, the Board would be open to such comparables, because they would provide information on the perspective of participants in competitive markets with regard to risk.

The Board notes that Dr. Vilbert acknowledged that the risks of unregulated operations are generally expected to be higher than regulated operations. The evidence also showed that DBRS views the unregulated portions of utility businesses to be of higher risk and that DBRS requires that utilities offset their exposures to unregulated activities with lower financial risk, in order to achieve a comparable rating. Despite Dr. Vilbert's contention that the unregulated activities' higher risks would not necessarily mean that the estimated cost of capital would be higher, the Board is of the view that in the case of his samples, on average it would be expected to mean exactly that.

As a consequence, the Board is of the view that in the context of all the samples presented in this case, the presence of unregulated operations in the sample companies implies that the estimated costs of capital are likely capturing to some extent the higher cost of capital of the unregulated activities.

Conclusion

In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008.

The Board was informed by all of the financial market returns comparable groups presented as evidence by both parties. Consistent with the Board's decision in Chapter 4 to rely on a market-based ATWACC methodology, the Board has put principal weight on market-determined returns as opposed to regulatory returns. These market-determined returns of companies found to be of comparable risk to TQM, combined with the market-value capital structure, provide the Board with crucial information for determining TQM's cost of capital for 2007 and 2008. How this information was used to determine the fair return for TQM is explained in Chapter 7.

Chapter 7

Fair Return for TQM for 2007 and 2008

Reliance on an aggregate approach to cost of capital involves comparing total costs of capital of comparable companies, rather than comparing the costs of individual cost of capital components. This Chapter first addresses the total fair return for TQM for 2007 and 2008, and then the manner in which the return may be implemented.

7.1 Total Return

Table 7-1 summarizes the recommendations made by various parties for the cost of capital for TQM for 2007 and 2008. One implication of using an ATWACC methodology is that the returns recommended by parties may be conveniently examined on a comparable basis. Some parties (CAPP, IGUA and Ontario) made recommendations for individual components of cost of capital, while others (TQM and CGA) stated the aggregate cost of capital implications of their recommendations. For ease of comparison all are presented using ATWACC or ATWACC equivalence in Table 7-1.

Submissions of TQM

As outlined in Section 1.2 of these Reasons, TQM requested return on capital components of 11 per cent ROE on 40 per cent equity thickness, plus the embedded cost of debt on the remaining 60 per cent of the capital structure. TQM's current embedded interest rate on the 60 per cent funded debt is 6.14 per cent. A further (unfunded) 10 per cent was set at 5.69 per cent in 2007 and 5.5 per cent in 2008. TQM indicated that it started with an ATWACC of 6.65 per cent, which is based on the market value of debt. The Application included an adjustment for the difference between market and embedded costs of debt, resulting in an ATWACC of 6.9 per cent. However TQM indicated it could accept a 6.65 per cent aggregate return when using market returns for both debt and equity.

TQM submitted that the financial integrity requirement is met when the total return allows TQM to maintain its financial integrity, including acceptable bond ratings and coverage ratios, on a stand-alone basis. Acceptable bond ratings and coverage ratios impact a utility's cost of capital which is ultimately reflected in the reasonableness of the terms and conditions upon which the utility can attract capital. Currently, S&P and DBRS rate TQM at BBB+ and A (low) respectively, both investment grade ratings. TQM submitted that these ratings reflect the implicit credit support of its parents which could potentially violate the stand-alone principle. According to Mr. Murphy, if Moody's were to apply a credit rating to TQM, it would assign a Ba1 rating which is below investment grade.

Table 7-1
Summary of Returns Recommended for TQM for 2007 and 2008

(per cent, unless specified otherwise)

Party	Equity Thickness[1]	Return on Equity	Debt	Equivalent Total Return After-tax[2]
TQM	40	11	Embedded	6.9
	n/a	n/a	Embedded	6.9
	57.5 to 60	RH-2-94 Formula [4]	Embedded	6.9
TQM [3]	n/a	n/a	Market	6.65
CGA				200 to 300 basis points above current [6]
CAPP		RH-2-94 Formula [4]		5.4 to 5.5 (2007) [7]
	30 to 32		Embedded	5.5 to 5.6 (2008) [7]
		or 7.75 [5]		5.2 to 5.3 [7]
IGUA	32	RH-2-94 Formula [4]	Embedded	See CAPP above
Ontario	36	RH-2-94 Formula [4]	Embedded	5.7 (2007) [7]
				5.8 (2008) [7]

1 Book equity / (book equity plus book debt)
2 Where the after-tax return is impacted by tax rates, e.g. when computing an after-tax debt cost, a tax rate of 32 per cent is assumed.
3 The TQM recommendations had started from the analysis of Dr. Kolbe and Dr. Vilbert which derived an ATWACC range of 6½ to 6¾ per cent, before adjusting from market to embedded cost of debt, an adjustment of 0.24 percentage points.
4 The RH-2-94 Formula return on equity is 8.46 per cent (2007) and 8.71 (2008).
5 If the RH-2-94 Formula were to be re-opened, then CAPP recommended that the current value of the return on equity be 7.75 per cent.
6 The current value for TQM is 5.4 to 5.5, as computed by the Board.
7 As computed by the Board.

Submissions of Intervenors

CGA argued that, regardless of any possible change in approach, it is necessary to eliminate the 200 to 300 basis point deficit in total returns that has emerged in Canadian formula-based returns.

Spectra and Union indicated their support for the TQM position. They recommended that the Board carefully examine whether the RH-2-94 Formula continues to represent a fair return. They did not recommend a specific return for TQM for 2007 and 2008.

In CAPP's view, the ROEs determined by the RH-2-94 Formula of 8.46 per cent and 8.71 per cent provide a more than fair return for TQM for 2007 and 2008. As to equity thickness, CAPP offered a range, based on Dr. Booth's assessment, of 30 per cent if the basis of comparison were whether TQM's business risks have changed since the RH-2-94 Decision, or 32 per cent based on comparisons with Alberta transmission operators and the EUB 2003 decision on AltaLink. CAPP took no position on the cost of debt as applied for by TQM, arguing that use of embedded debt and the RH-2-94 Formula remains valid. CAPP did not dispute TQM's submission regarding debt ratings and argued that the current return allowed to TQM cannot be unfair since TQM has been able to maintain good and stable investment grade bond ratings.

According to Ontario, as a stand-alone entity, TQM continues to be capable of attracting sufficient capital. An increase in the company's equity thickness to 36 per cent and the retention of the RH-2-94 Formula would be more than sufficient to maintain TQM's ability to attract capital on favourable terms for both the short and long-term.

IGUA recommended that the Application for any increase in the equity thickness beyond 32 per cent be denied, noting that in its 2006 Annual Report, TQM stated that a 36 per cent deemed equity thickness would be appropriate, not the 40 per cent sought in the Application. IGUA contended that even the increase to 36 per cent was unnecessary, given its views on TQM's risks as outlined in Chapter 5. IGUA further noted that in its 2006 Annual Report TQM was not looking for any increase in its ROE. IGUA submitted that a request for anything more than the RH-2-94 Formula should be denied.

7.2 Total Return and Capital Structure

The total return determined to be fair could be granted in a number of different ways. The Board sought perspectives from parties on whether they had preferences regarding returns granted as a total return, or as distinct returns on equity and on debt, with a Board deemed capital structure.

Submissions of TQM

As shown in Table 7-2, TQM demonstrated that the three combinations discussed in the Application ("11 on 40", "Formula on 60" and single ATWACC) were approximately equivalent in terms of revenue requirement, and could result in only one possible toll. TQM indicated that in all cases the after tax return would need to be grossed up for taxes, by dividing the equity return by 1 minus the approximately 32 per cent tax rate, the average tax rate of the TQM owners. In the third case shown in Table 7-2, the income taxes treat the return on capital as though it were 100 per cent based on equity with no tax deductions for debt payments.

Although TQM had a preference for the 11 per cent on 40 per cent equity, it viewed the three alternatives as equivalent because the sum of returns and taxes would not change.

Table 7-2
Implications for 2008 Revenue at a 6.9 per cent ATWACC ($000)

Three Alternative Cases Presented by TQM	Return on Capital	Income Taxes: Related to Return on Capital	Income Taxes: Timing Difference and Other [1]	Sum of Return and Income Taxes
11 on 40 calculated using the traditional approach	36,644	9,459	2,109	48,212
Formula on 60 calculated using the traditional approach	34,797	11,241	2,109	48,147
6.9% ATWACC, with no ROE or capital structure specified [2]	31,254	14,833	2,109	48,196

From TQM's Notes:

1. The $2,109,000 Tax on Timing Differences and Other is not sensitive to return and is the same in all 2008 cases.
2. In the 6.9% ATWACC case, return is the 2008 rate base ($452,962,000) times 6.9%, and the income taxes related to return on capital use a gross up percentage of 47.46% times the return on capital.

Each of TQM's owners, TransCanada and Gaz Métro, indicated that they address their total debt on a consolidated basis, and target a specific rating and contended they would not have the same incentives to consider the tax benefits of debt as a non-regulated company.

TransCanada indicated that, dependent on how the total return was granted to TQM, it would possibly reconsider how it financed its investment in TQM. For example, if TQM were granted the Formula on 60 per cent equity thickness, TransCanada indicated that it would not actually carry 60 per cent equity for the TQM investment in the TransCanada capital structure as that level is not required to satisfy rating agencies. TransCanada currently has roughly 40 per cent equity thickness in its market value capital structure. Gaz Métro also indicated that, regardless of the manner in which the award was granted, it is likely to carry a corporate equity thickness of 40 per cent.

With regard to the tax benefits from optimizing TQM's financial leverage, TransCanada acknowledged that at least part of its benefit from offshore financing refers to the structure called double dip, where an entity can legally deduct interest in two jurisdictions, in this case interest paid in Canada and interest paid in the U.S. However, TransCanada indicated that TQM's position remains consistent with the regulatory standard of looking at an entity as stand-alone, and not considering TQM as an integrated part of a larger corporation. As each of their alternative proposals for a fair total return would result in the same revenue requirement, TQM indicated that there would be no wealth transfer.

Submissions of Intervenors

CAPP suggested that the capital structure decisions could produce a wealth transfer dependent on who benefits from optimizing TQM's capital structure. Regulated companies have traditionally been allowed to include in their revenue requirement an allowance for income taxes, reflecting the deemed capital structure, allowed cost of equity and actual cost of debt. As interest is tax deductible, an aggregate cost of capital can be minimized through the use of debt. Traditional regulatory approaches have explicitly assigned this reduction in aggregate cost of capital to the shippers. CAPP expressed concern that, if a total return were granted without specifying the capital structure, the revenue requirement would include provision for taxes which may not necessarily be paid, particularly as the regulated company is held within a holding company structure.

CAPP submitted that granting an aggregate cost of capital allows a holding company, as owner of the regulated utility, to use some leverage at the holding company level, rather than at the subsidiary level where it could benefit shippers. This has been referred to as double leverage. Dr. Booth indicated that this occurs in Canada, and demonstrates that full leverage is not used at the regulated business unit level. Further, a holding company with international businesses may be able to reduce income taxes by utilizing additional deductions.[35] However Dr. Booth agreed that any such leverage would not impact what is charged to toll payers, as long as the ATWACC was constant.

35 Some of such deductions involve structures referred to as double dip.

Dr. Safir suggested that granting a total return without specifying a capital structure would alter risks, and that it would be better and more efficient to see the components even if the results were the same.

For both CAPP and IGUA, separately addressing the rate of return on equity and the appropriate capital structure is convenient and useful, and should be retained.

7.3 Adjusting for the Embedded Cost of Debt

Submissions of TQM

In its application, TQM asked that its allowed return be adjusted for the difference between the market cost of debt and the actual cost of TQM debt.[36] TQM acknowledged that a pure ATWACC approach would be based on the market value of each component, and would not adjust for the embedded cost of debt. Dr. Kolbe indicated that a pure ATWACC methodology would be superior from an economic perspective to a hybrid methodology that uses the ATWACC and the embedded cost of debt. On a conceptual basis, under an ATWACC regime, TQM argued that a utility would come back to the regulator when there are changes in the cost of capital, as driven by the market cost of equity or debt.

If the Board were to award returns on market-based ATWACC including the market cost of debt, Dr. Kolbe urged the Board to think about transition issues and decide whether the difference between market and embedded debt costs reached a level of materiality needing a transition adjustment from the past approach. TQM indicated that, if required, it would accept a return that did not provide for the difference between embedded and market cost of debt. TQM indicated that if it were allowed an ATWACC with the market cost of debt it would not return to the Board for a change in cost of capital even if its debt costs changed for 2007 and 2008, since the decision in this case is being made on a retrospective basis.

Submissions of Intervenors

Dr. Booth submitted that the use of a single market-based ATWACC to grant a return would make the utility accountable for the timing of its debt issues. Providing this implicit allowance for the market cost of debt would be a significant departure from regulatory practice in Canada, and would tend to make the equity more risky, altering many aspects including volatility and betas observed in the market. He submitted that in the traditional practice, shippers bear the risk that embedded debt costs rise above market debt costs, and are compensated for bearing that risk by a lower cost of capital in the tolls. Dr. Booth considered that moving that risk to the pipeline had implications for the use of deferral accounts and other components of the regulatory bargain, and that the added risk imposed on the system would not be offset by obvious benefits.

IGUA indicated that it preferred using the actual cost of debt, rather than regularly adjusting to market rates. This view was expressed in the context of continuing to use the current methodology for determining the return on common equity. Similarly Ontario noted the Board's

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36 TQM's current embedded interest rate on the 60 per cent funded debt is 6.14 per cent. A further (unfunded) 10 per cent is financed at the prime rate less 0.5 per cent, that is, 5.69 per cent in 2007 and 5.5 per cent in 2008. Dr. Vilbert used 5.5 per cent for the market cost of debt.

standard practice of allowing TQM to include the actual cost of debt in its revenue requirement for recovery from customers through tolls and had no objection to continuing this practice along with continued reliance on the RH-2-94 Formula.

Views of the Board

In determining the fair return for TQM for 2007 and 2008, the Board used judgment to bring the evidence together to reach an overall conclusion. The Board has not assigned quantitative values to the adjustments made for individual elements of the evidence nor has it assigned quantitative weights to the various opinions presented in this hearing. Figure 7-1 was prepared to provide an overview of the factors that the Board considered and the extent of their influence on the Board's decision.

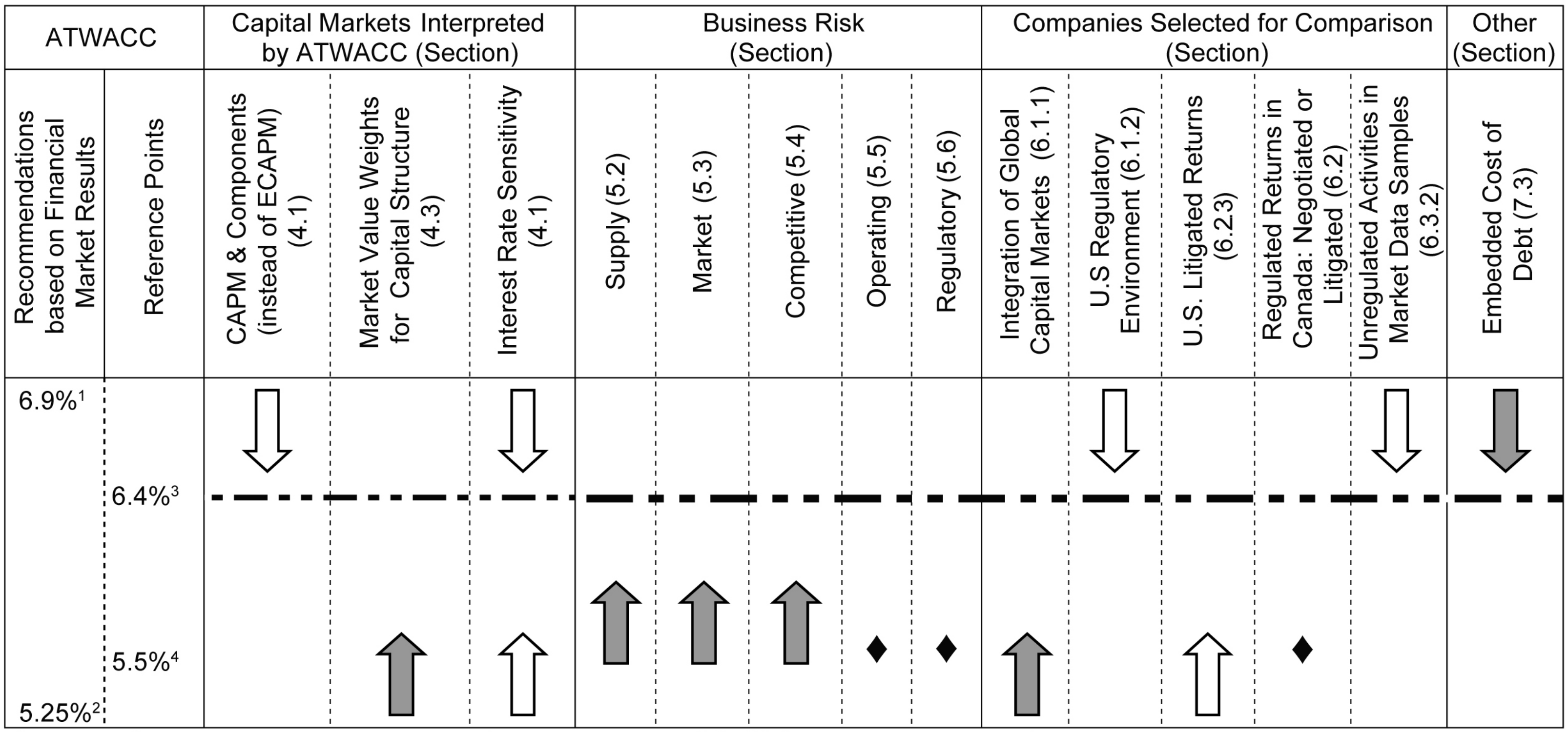
The factors included in Figure 7-1 have been discussed in greater length in earlier sections. Having decided, as described in Chapter 3, to vary from the RH-2-94 Formula, the Board considered all evidence on the estimation of cost of capital. The Board examined the evidence in ATWACC terms to reach a finding on the fair return in this particular case.

In the Board's opinion, an ATWACC methodology enables the comparisons of aggregate returns on an equal footing between companies of comparable risk by substantially neutralizing the effect of financial risk attributable to different capital structures. Consequently this methodology better utilizes financial market information. Further, it produces a single number which aligns with the manner that many businesses assess capital projects.

As explained earlier, the Board relied on CAPM for the market cost of equity. The Board considers the market value capital structure to be the appropriate way to combine the estimated market costs of equity with the market cost of debt, on an after-tax basis, to derive market-based ATWACC estimates for sample companies. The Board recognizes that there is interest rate sensitivity in regulated utility returns. However, for reasons discussed in Chapter 4, the Board did not rely explicitly or exclusively on either of the methodologies offered (adjusted betas or a two-factor model) in this proceeding.

These factors were taken into account when examining the recommendations which were based on financial market results from samples of companies. These recommendations are included in the first column of Figure 7-1. However, not all of the proposed comparable companies have risk at the level of TQM, and as discussed in Chapter 6, the Board has considered such differences in weighing the estimated costs of capital of the various samples.

Figure 7-1
Illustration of Factors and their Influence on the Board's Decision on a Total Return for TQM for 2007 and 2008



1. Each of the combinations requested by TQM match an ATWACC of 6.9 per cent, see Table 7-1.
2. The result of CAPP's recommendation of the 7.75 per cent on 30 to 32 per cent equity, if the request to vary the RH-2-94 Formula were granted, see Table 7-1.
3. The total return set by the Board.
4. The status quo, with 30 per cent equity and the (2008) RH-2-94 Formula. CAPP's recommendation of the RH-2-94 Formula on 30 to 32 per cent equity, if the request to vary the RH-2-94 Formula were denied, would be in a 5.4 to 5.6 per cent range for ATWACC. (See Table 7-1)

Legend: The size of the arrows has no implication for quantitative contribution to the Board's decision. Arrows are positioned to show movement from a starting point.

Material Influence

Limited Influence

◆ No Influence

In the Board's opinion, many factors interact in natural gas markets and provide the context for the business risk of TQM. While the Board found no change since 1994 in TQM's regulatory and operating risks, the changing dynamics of the natural gas end-use markets, pipeline competition and changing potential supply sources have combined to create greater business risk for TQM.

The Board did not take into account the stated results from negotiated settlements for Canadian pipelines, nor did it rely on the allowed returns determined in Canadian litigated proceedings. However the market returns for Canadian utilities were helpful to the Board since these returns demonstrate the market's assessment of the firms' costs of capital.

The Board found market returns of U.S. companies to be relevant to the cost of capital of Canadian firms, as U.S. market returns can be a useful proxy for investment opportunities in the increasingly integrated global capital markets. In the Board's view, Canadian and U.S. natural gas markets have many similarities. For instance, these markets operate in similar regulatory environments. However, as discussed in Chapter 6, the Board found that generally TQM faces less risk than U.S. companies which were proposed as comparables.

Fair Return Determination

Having carefully considered the evidence and assessed the factors influencing TQM's total return, the Board concludes that an ATWACC of 6.4 per cent on rate base is the fair total return for TQM for 2007 and 2008.

In the Board's view, the total return of 6.4 per cent will be in line with those of North American pipelines found to be of comparable risk. The resulting risk-reward profile of TQM will be in line with those of other comparable investments presented as evidence. The Board is therefore of the view that the aggregate return of 6.4 per cent will ensure that TQM's total return on capital meets the comparable investment requirement.

The Board is also of the view that the total return of 6.4 per cent will help TQM maintain its credit rating on a stand-alone basis. As a result, the Board believes that TQM will continue to maintain its financial integrity and its ability to attract capital on reasonable terms and conditions.

The Board finds that the total return of 6.4 per cent satisfies the Fair Return Standard, as articulated in Chapter 2 of these Reasons.

A Single Market-Based Return

The Board accepts TQM's demonstration that the alternative capital structures provided in the Application each produce the same revenue and toll results, for a constant market-based ATWACC. All parties indicated that, irrespective of the capital structure chosen, there can be only one toll for a given ATWACC number.

The Board notes that the provision for actual or embedded debt costs, and the allowance for estimated income taxes payable based on the deemed capital structure, are part of the traditional approach to toll making which considers the individual components of the cost of capital. However, the Board has decided to set an aggregate return on capital, guided by market-based principles. The Board is not specifying TQM's capital structure for 2007 and 2008. In keeping with that perspective, the Board finds that a fair treatment of embedded debt costs is to consider such costs to be accounted for in the market-based ATWACC number. In this regard, the Board subscribes to the views expressed by Dr. Kolbe to the effect that, notionally, this is the superior way from an economic perspective.[37]

The Board's decision to grant an aggregate return on capital without specifying capital structure has the result of transferring to the pipeline company the decision to determine its optimal capital structure and choose specific financial instruments without regulatory oversight. The freedom for a company to choose its optimal capital structure is consistent with the Board's philosophy of regulating pipeline companies on a goal-oriented basis. Exercise of that freedom does not, in the Board's view result in a wealth transfer, and is supported by the longstanding stand-alone principle.

The difference between market cost of debt and embedded cost of debt in this case is small and therefore does not require consideration of a grandfathering or transition phase for TQM for 2007 and 2008.[38]

In support of transparency, the Board requires that TQM report the amount of leverage that is supported by TQM in the owners' capital structures as of the end of 2008.

37 At transcript volume 9, para. 11562 Dr. Kolbe stated: "a pure ATWACC methodology would be economically superior to a hybrid methodology that gives you the ATWACC and the embedded cost of debt from an economic point of view."

38 To facilitate comparisons, the table below provides some combinations of ROE and equity thickness which, when combined with actual debt costs, are equivalent to the market-based ATWACC of 6.4 per cent set by the Board.

Equity Thickness, per cent	Return on Equity, per cent
40 (As requested by TQM)	9.7
32 (As recommended by CAPP)	11.2
50.5	8.46 (Using 2007 ROE from the RH-2-94 Formula)
49	8.71 (Using 2008 ROE from the RH-2-94 Formula)

Decision

The Board is allowing TQM to include in its revenue requirement for 2007 and 2008 a provision for after-tax weighted average cost of capital of 6.4 per cent.

TQM is directed to file for final tolls for 2007 and 2008 using this information, and to report the amount of leverage that is supported by TQM in the owners' capital structures as of the end of 2008. These filings are due by 30 April 2009.

Chapter 8

Disposition

The foregoing chapters constitute our Reasons for Decision in respect of the application considered by the Board in the RH-1-2008 proceeding.

G. Caron
Presiding Member

R.R. George
Member

G.A. Habib
Member

Calgary, Alberta
March 2009

Appendix I

Ruling 1 – 30 September 2008

Yesterday, the Board heard submissions by counsel for TQM and counsel for CAPP regarding the use that can be made, during an oral proceeding, of documents filed in response to IRs, but which remain available in a "reading room" established at the office of counsel for TQM.

Counsel for TQM stated that documents from the reading room and referred to during the hearing may be referred to in their entirety on the record during a proceeding.

Counsel for CAPP took the position that only those portions of the reading room documents put to witnesses by a cross-examiner and then expanded on by the witnesses with further related portions of the documents are considered to be accepted onto the record.

This is the Board's ruling on the matter.

The Board's traditional practice is that where a party seeks to use a document for the purpose of aiding their cross-examination, subject to relevance being established, the Board will allow the document to become an exhibit only for the excerpts that have been put to the witnesses and discussed between the examiner and the witnesses.

In this instance, TQM through its counsel has established a reading room to ensure that documents referred to in IRs, which would otherwise be filed on the record and which would be voluminous, remain accessible to all parties without creating a record that might otherwise become unwieldy. The Board finds this approach acceptable and encourages the concept of such a reading room.

The reading room documents, in the Board's view, are different from those produced by a cross-examiner as an aide to cross. The documents associated with IR responses and placed in a reading room have been made available in the information exchange as part of the evidence filed in response to IRs and are available to parties to examine ahead of the hearing. They are, in essence, the evidence of the party answering the IRs.

As such, the Board is of the view that documents or portions of documents from the reading room reproduced and presented in the hearing for the purpose of cross-examination, should be admitted in their entirety. That is, the entire document or excerpt of the document if it is lengthy (such as a text book) will be considered to be on the record, not just the passages which are brought to the witnesses' attention.

The witness to whom the document is being put may draw the Board' attention to other portions of the document either in the excerpt version produced by the cross-examiner, or if needed, by producing a longer or different version of an excerpted document.

The cross-examiner who introduced the original, shorter document will be given the opportunity to cross-examine on the other portions.

The Board recognizes that this is somewhat a change in process mid-stream of this hearing. Therefore the Board is willing to hear from parties if they have any concern regarding the documents entered to this point in time.

Appendix II

Ruling 2 – 2 October 2008

Yesterday, Mr. Yates objected to questions by Mr. Schultz on the reply evidence of TQM. The evidence cited the argument of CAPP in an EUB hearing in 1994. This argument was based on the evidence of CAPP's expert in that proceeding, Mr. Hugh Johnson.

In the Board's view, as this evidence was submitted as TQM's reply evidence, Mr. Schultz is entitled to cross-examine on it.

However, the Board notes that

- neither TQM nor CAPP are relying on Mr. Johnson's evidence for the truth of the content;
- Mr. Johnson is not here to speak to the evidence; and
- there has been a significant passage of time since that evidence was filed and the argument based on that evidence was made, which may mean that there are changes which would have affected Mr. Johnson's position.

Therefore, the Board is inclined to give little weight to this portion of the reply evidence. The Board would also point out, for guidance to counsel, that it finds helpful that cross-examination which assists it in understanding the evidence before it and the current position of parties.

The Board directs counsel to govern themselves accordingly in the way in which they cross-examine on this evidence. Mr. Schultz, if you have some limited questions on this matter, you may proceed.

Appendix III

Ruling 3 – 7 October 2008

Yesterday, Mr. Schultz objected to questions Mr. Yates posed to the CAPP policy witness regarding the adoption of the evidence presented by Dr. Booth and Dr. Safir as that of CAPP.

Mr. Schultz argued that a party presenting expert evidence is not required to accept that expert's evidence as their own although that party adopts the conclusions reached by their expert.

Mr. Yates put forward the view that if a party is not willing to accept its expert's evidence in its entirety, then that evidence should not be accepted by the Board and should therefore be struck. Otherwise, what would a party have the Board do with the expert evidence that is not accepted by the party submitting that evidence.

Expert evidence is submitted for two main reasons. First, an expert can provide information necessary for a further understanding of technical issues before the Board. Second, an expert's evidence can further aid the Board drawing inferences from the technical information presented.

When presenting expert evidence for the Board's consideration, the Board expects that CAPP would develop a degree of comfort with the methodology used by CAPP's experts to reach the conclusions which CAPP relies on. In other words, the Board would expect that CAPP, in seeking to rely on the conclusions of Drs. Booth and Safir, would hold compatible views on the opinions and methodology as those presented by the experts.

An expert is generally retained because of the complexity of the matter in question. The Board does not expect that CAPP's policy witnesses would be able to speak to the specifics of the expert's evidence nor defend the details presented in the current proceeding or in future proceedings.

Further, should a party seek to discredit CAPP's position in a future hearing by using CAPP's expert evidence from this hearing, the Board is of the view it would be incumbent upon the impugning party to produce the witness whose evidence they seek to demonstrate is contradictory.

Additionally, as noted in the Board's earlier ruling in this hearing regarding questions of an expert of CAPP in a previous proceeding, if there has been a significant passage of time since the evidence was filed, the Board understands that changes may have occurred which would have altered that expert's opinion.

The Board is of the view that an expert's evidence must be adopted by the party filing that evidence within the parameters discussed in this ruling.

Mr. Schultz, do you wish to have CAPP's policy witnesses adopt the expert evidence that they sponsored in this proceeding? Feel free to take some time to consider this matter.

Attachment 5.2

File Of-Tolls-TollsGen-COC 01
3 July 2009

To: Parties Named in the Attached Distribution List

Review of the Multi-Pipeline Cost of Capital Decision (RH-2-94)

Background

On 23 March 2009, the National Energy Board issued a letter advising that it had decided to consider whether it should initiate a review, pursuant to section 21 of the *National Energy Board Act*, of the RH-2-94 Decision. The Board solicited comments from interested persons on whether they believe that the RH-2-94 Decision should be reviewed. The Board indicated that those providing comments should include the grounds for their submission, along with their views on the process which should be used and the issues to be considered if a review is held. The Board set a deadline for comments of noon, Calgary time, Monday, 25 May 2009.

Decision and Further Process

Having considered the submissions of parties, the Board has decided to initiate a review of the RH-2-94 Decision by seeking comments on the continuing applicability of the RH-2-94 Decision. Interested persons are asked to provide comments by filing them with the Board by **noon, Calgary time, Friday, 18 September 2009.**

The Board will take into account comments already filed on this matter pursuant to its 23 March 2009 letter when making its decision. Parties need not file any further submissions unless they have supplementary comments not covered by their earlier submissions.

In providing their submissions, parties may wish to provide comments on the following possible outcomes.

- The RH-2-94 Decision remains in effect, without prejudice to parties filing company-specific applications to depart from the RH-2-94 Decision.
- The RH-2-94 Decision will not continue to be in effect and an appropriate method of and timing for transition for any pipeline still subject to the RH-2-94 Decision, and those pipelines utilizing the RH-2-94 Formula, will be implemented.

…/2

- The initiation of a generic process, which could be a formal generic hearing, or any other process developed by interested parties, to examine the manner in which, going forward, the Board should address the cost of capital.

Interested parties may suggest alternative outcomes when providing comments on whether the Board should depart from the RH-2-94 Decision. For example, parties could suggest a collaborative process led by interested stakeholders, in lieu of or in combination with the above possible outcomes, to develop a proposal for the Board's consideration and approval.

Notice and Accessibility of Correspondence

Companies in Part A of the attached Distribution List are directed to serve a copy of this letter on their shippers and interested parties, including parties to their latest tolls decision or settlement. They need not serve a copy on any person listed in Part B.

Parties are advised that copies of correspondence related to this process can be found on the Board's Regulatory Documents Repository (accessible by visiting the Board's Internet site at www.neb-one.gc.ca. Click on the "View" link under the Regulatory Documents heading). In the Repository, click on "Group 1 Gas" or "Group 1 Oil". Then click on "Multi-Client Cost of Capital (RH-2-94)"; then click on "1994-06-20 Cost of Capital (RH-2-94)"; and finally click on "2009-03-23 - Request for Comments on Review of RH-2-94 Decision". Alternatively, some recent filings may be found by clicking on "Inbox" from the Repository home page.

Yours truly,

AnneMarie Erickson

for Claudine Dutil-Berry
Secretary of the Board

Attachment

Liste de distribution

<u>Method of Service</u>
Efile Notification
Télécopieur
Courier

<u>Part A</u>

Alliance Pipeline Ltd.	rob.power@alliance-pipeline.com
Enbridge Pipelines Inc.	helene.long@enbridge.com
Enbridge Pipelines (NW) Inc.	ralph.fischer@enbridge.com
Express Pipeline Limited Partnership	brenda_mcclellan@kindermorgan.com
Foothills Pipelines Inc.	murray_sondergard@transcanada.ca
Gazoduc Trans Québec & Maritimes Inc.	botis@gazoductqm.com
Kinder Morgan Cochin ULC	brenda_mcclellan@kindermorgan.com
Maritimes & Northeast Pipeline Management Ltd.	ileadley@spectraenergy.com
NOVA Gas Transmission Ltd.	greg_szuch@transcanada.com
	patrick_keys@transcanada.com
TransCanada PipeLines Limited	murray_sondergard@transcanada.com
Trans Mountain Pipeline Inc.	brenda_mcclellan@kindermorgan.com
Trans-Northern Pipelines Inc.	jlang@tnpi.ca
Westcoast Energy Inc., carrying on business as Spectra Energy Transmission	melthorp@spectraenergy.com

Part B

(*RH-2-94 – Interested Parties List*)

Alberta Department of Energy	regaffairs.energy@gov.ab.ca
B.P. Canada Energy Co.	cheryl.worthy@bp.com
BC Hydro and Power Authority	bchydroregulatorygroup@bchydro.com
City Of Calgary	Mark.Rowe@calgary.ca
Canadian Association of Petroleum Producers	jardine@capp.ca
Canadian Energy Pipeline Association	brendakenny@cepa.com
Canwest Gas Supply Inc.	Courier
Centra Transmission Holdings Inc.	jbrophy@efgroupllc.com
Centra Gas Manitoba Inc.	baczarnecki@hydro.mb.ca
Council of Forest Industries of British Columbia	mauch@cofi.org
Enbridge Gas Distribution	tania.persad@enbridge.com
EnCana Corporation	rinde.powell@encana.com
Export Users Group	weislawe@shaw.ca
Gaz Métro	kasselin@gazmetro.com
Huntingdon International Pipeline Corporation	604-592-7620
Imperial Oil Resources	ronald.moore@esso.ca
Industrial Gas Users Association	mnewton@igua.ca
New England Power Company	508-389-2605
Northern Border Pipeline Company	Loretta.McGowan@Nborder.com
Plains Marketing Canada, L.P.	403-233-0399
Province of Ontario	416-326-6996

Province de Québec	418-643-7524
Rochester Gas and Electric Corporation	marjorie_perlman@rge.com
Shell Canada Limited	paul.m.davies@shell.com
Terasen Gas Inc.	regulatory.affairs@terasengas.com
Teck Cominco Metals Ltd.	604-631-3232
TransAlta Corporation	403-267-2575
Union Gas Limited	pplanting@uniongas.com

(Other Pipeline Companies)

1057533 Alberta Ltd. / Harvest Operations Corp	403-265-3490
2193914 Canada Limited	tania.persad@enbridge.com
Abitibi-Consolidated Company of Canada	514-394-3624
Agent and General Partner of the Pembina North Ltd. Partnership Pouce Coupé Pipe Line Ltd.	dzacharias@pembina.com
AltaGas Pipeline Partnership	403-691-7576
Apache Canada Ltd.	anita.bianchie@apachecorp.com
ARC Resources Ltd.	403-503-8645
ATCO Utilities	780-420-7400
Bear Paw Processing Company (Canada) Ltd.	701-565-2229
Berens Energy Ltd	403-265-5587
Burlington Resources Canada (Hunter) Ltd.	403-260-6000
Canada Border Services Agency	306-780-7750

Canadian Natural Resources Limited	bryan.bradley@cnrl.com
Canadian – Montana Pipeline Corporation	Courier
Champion Pipe Line Corporation Limited	514-598-3144
Chief Mountain Gas Co-Op Ltd.	Courier
Cresent Point Resources Ltd	403-693-0070
County of Vermillion River No. 24 Gas Utility	780-846-2716
Delphi Energy Partnership Delphi Energy Corporation	403-265-6207
Devon Canada Corporation	keith.fardy@devoncanada.com
DR Four Beat Energy Corporation	406-862-0715
Dome NGL Pipeline Ltd.	Suzanne.Boucher-chen@bp.com
EB Eddy Forest Products Ltd. c/o Domtar Inc.	Courier
Echoex Energy Inc.	403-265-4354
Enbridge Pipelines (Westspur) Inc.	Peter.Taylor@enbridge.com
EnCana Ekwan Pipeline Inc	403-645-3054
EnCana Oil & Gas Company Ltd.	rinde.powell@encana.com
EnerMarck Inc.	403-298-2211
ExxonMobil Canada Properties	902-496-0958
Forty Mile Gas Co-Op Ltd.	Courier
Fraser Papers Inc. (Canada)	506-737-2100
Glencoe Resources Ltd.	dave.brown@glenres.ca
Holland & Knight	202-955-5564
Husky Oil Operation Limited	susan.anderson@huskyenergy.ca

ISH Energy Ltd.	403-265-1792
Kaiser Exploration Ltd.	403-265-3161
Keyera Energy Ltd.	403-205-8318
Many Islands Pipe Lines (Canada) Limited	306-565-3332
Mid-Continent Pipelines Limited	306-352-8892
Minell Pipeline Limited	204-475-2452
Montreal Pipe Line Limited	514-645-7663
Murphy Canada Exploration Company	403-233-2565
Nexen Inc.	shannon_young@nexeninc.com
Niagara Gas Transmission Limited	tania.persad@enbridge.com
Nova Chemicals (Canada) Ltd.	mcdougcd@novachem.com
NuVista Energy Ltd	403-538-8575
Omimex Canada Ltd.	817-735-8033
Paramount Transmission Ltd	403-262-7994
Peace River Transmission Company Limited	604-697-6210
Pengrowth Corporation	pengrowth@pengrowth.com
Penn West Petroleum Ltd.	403-777-2670
Pioneer Natural Resources Canada	tracey.bell@pxd.com
PMC (Nova Scotia) Company	403-233-0399
Portal Municipal Gas Company Canada Inc.	306-721-9220
Provident Energy Ltd.	rlock@providentenergy.com
SCL Pipeline Inc.	Courier

Shiha Energy Transmission Lt.	tom.hong@paramountres.com
Souris Valley Pipeline Limited	306-848-0293
Spectra Energy Empress LP	mkelly@spectraenergy.com
Spectra Energy Midstream Canada LP	BLMoore1@spectraenergy.com
St. Clair Pipelines Management Inc.	902-425-4592
Suncor Energy Inc.	416-733-8048
Sun-Canadian Pipe Line Company	215-977-3409
Sword Energy Ltd.	403-770-4850
Talisman Energy Inc.	403-237-1902
Taurus Exploration Canada Ltd	Courier
TransCanada Keystone Pipeline GP Ltd.	kristine_delkus@transcanada.com
True Energy Inc.	403-264-8163
Vault Energy Inc.	403-262-5524
Vector Pipeline Limited Partnership	734-462-0231
Wolstitmor Joint Venture	403-513-3750
Yukon Pipelines Ltd.	bhedges@russelmetals.com

(*Interesed Parties*)

The Honourable Robert Douglas Nicholson, P.C., Q.C., M.P. Minister of Justice & Attorney General of Canada	613-990-7255
The Honourable Wally Oppal Attorney General & Minister Responsible for Multiculturalism Province of British Columbia	250-387-6411

The Honourable Alison Redford, Q.C. Minister of Justice & Attorney General and Government House Leader Province of Alberta	780-422-6621
The Honourable Don Morgan Minister of Justice & Attorney General Province of Saskatchewan	306-787-1232
The Honourable Dave Chomiak Minister of Justice and Attorney General Government House Leader Province of Manitoba	204-945-2517
The Honourable Chris Bentley Attorney General of the Province of Ontario	416-326-4007
L'Honourable Kathleen Weil Ministre de la Justice du Québec Procureure générale Notaire génerale du Québec Ministre responsable des lois professionnelles	418-646-0027
The Honourable Thomas J. Burke, Q.C. Attorney General Minister of Justice and Consumer Affairs Province of New Brunswick	506-453-7154
The Honourable Cecil P. Clarke Attorney General and Minister of Justice Minister Responsible for Human Rights Act Minister Responsible for Regulations Act Province of Nova Scotia	902-424-0510
The Honourable Gerard Greenan Attorney General Province of Prince Edward Island	902-368-4910

The Honourable Thomas W. Marshall Minister of Justice & Attorney General Province of Newfoundland and Labrador	709-729-0469
The Honourable Marian Horne Minister of Justice Government of the Yukon Yukon Legislative Assembly	867-393-7400
The Honourable Jackson Lafferty Minister of Justice Minister of Industry, Tourism and Investment Government of the Northwest Territories	867-873-0276
The Honourable Eva Aariak Premier Minister of Executive and Intergovernmental Affairs Minister Responsible for the Status of Women Minister Responsible for Immigration Government of the Nunavut Territory	867-975-5051
Hydro One Networks Inc.	Susan.E.Frank@HydroOne.com
Sun Life Financial	416-595-1770

(Provincial Government Departments)

The Honourable Barry Barnet Minister of Energy and Minister Responsible for Conserve Nova Scotia Nova Scotia Department of Energy	902-424-3265
The Honourable Blair Lekstrom Ministry of Energy, Mines and Petroleum Resources OGD – Oil & Gas Division Province of British Columbia	250-356-2965

Mr. Stirling Bates
Director of Regulatory Policy
Oil and Gas Policy Branch
Ministry of Energy, Mines and Petroleum Resources
Province of British Columbia 250-952-0251

Ms. C. J. C. Page, Counsel
Director
Regulatory Affairs
Alberta Department of Energy 403-297-5499

Mr. Douglas Larder, Q.C.
General Counsel and Executive Director-Law
Alberta Utilities Commission 403-592-4406

Mr. Kent Campbell
Deputy Minister
Energy & Resources
Government of Saskatchewan 306-787-2159

Mr. Keith Lowdon
Director, Petroleum Branch
Science, Technology, Energy & Mines 204-945-0586

The Honourable John Gerretsen
Minister of the Environment
Ministry of the Environment
Province of Ontario 416-314-7337

Minister George Smitherman
Ministry of Energy and Infrastructure
Province of Onatrio 416-327-6754

Mr. Edward Sweet
Ministry of Energy and Infrastructure
Energy Markets Section
Energy Supply and Competition Branch
Office of Energy Supply, Transmission, and Distribution Policy
Province of Ontario edward.sweet@ontario.ca

M. Claude Béchard
Ministère des Ressources naturelles
et de la Faune
Province de Québec 418-643-4318

Mr. Paul Molloy, P.Eng.
Manager, Petroleum Engineering
Energy Branch
Government of Newfoundland and Labrador
Department of Natural Resources 709-729-2508

Office of the Utilities Consumer Advocate (Alberta) rmccreary@rmrf.com

(Associations)

Mr. David Butters
President & CEO
Association of Power Producers of Ontario appro@appro.org

Mr. Nick Schultz
Vice President, Pipeline Regulation and General Counsel
Canadian Association of Petroleum Producers 403-266-3123

Mr. David Podruzny
Vice President, Business and Economics
Secretary to the Board
The Canadian Chemical Producers' Association 613-237-4061

Mr. Michael Cleland
President and CEO
Canadian Gas Association 613-748-9078

Mr. Murray Newton
President
Industrial Gas Users Association 613-230-9531

Mr. Shane Pospisil
President and CEO
Ontario Energy Association 416-961-1173

Ms. Karmen Groza
Office Administrator/Office Manager
Small Explorers and Producers' Association of Canada 403-269-3636

Ms. Brenda Kenny
President
Canadian Energy Pipeline Association 403-221-8760

Mr. Pierre Guimond

President Canadian Electricity Association	613-230-9326
Mr. Paul Vogel Cohen Highley LLP	519-672-5960
Mr. David Core President Canadian Association of Energy & Pipeline Landowners Associations	DaveCore@caepla.org

Attachment 10.2

500 Consumers Road
North York, Ontario
M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

Lesley Austin
Regulatory Coordinator
Regulatory Proceedings
phone: (416) 495-6505
fax: (416) 495-6072

ENBRIDGE

VIA EMAIL AND RESS

October 7, 2008

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Consultation on Issues Relating to Low Income Consumers
Enbridge Gas Distribution Inc.
Board File No.: EB-2008-0150

Further to Enbridge Gas Distribution Inc.'s ("Enbridge") letter of October 3, 2008 and October 6, 2008, attached is Enbridge's revised response to the Ontario Energy Board's information request regarding the Winter Warmth Program.

Sincerely,

Lesley Austin
Regulatory Coordinator

cc: Fred Cass, Aird & Berlis (via email)
David Stevens, Aird & Berlis (via email)

ENBRIDGE'S RESPONSE TO
BOARD STAFF INFORMATION REQUEST – WINTER WARTH PROGRAM

INFORMATION REQUEST

Winter Warmth Program:

1) How much each utility is spending on the Winter Warmth Program
2) Number of applicants per year
3) The average Grant per applicant
4) The amount of money needed to meet the demand
5) Is the information different in different geographic areas of your service area? If so, how?

RESPONSE

1) Enbridge is spending $300,000 per year excluding top up from the Garland Settlement. The Garland Settlement provides an amount that can vary from year-to-year based on the annual return on the settlement amount. In the 2007-2008 heating season the Garland Settlement provided an additional amount of $354,000. Of the Garland Settlement top up, $166,000 was distributed to the Winter Warmth Program and the remaining $188,000 was distributed to the United Way Community Fund.

2) The total number of applicants for the 2007-2008 heating season was 1,099 excluding top up from the Garland Settlement or 1,523 including the Garland top up. The number of applicants receiving assistance was 700 without the Garland Settlement top up and 1,124 with the top up.

3) The average grant per participant was $353 net of the 15% fee paid to the agencies that administer the Winter Warmth program.

4) It is important to note that demand can and will vary from year-to-year based on many factors such as economic conditions, energy prices, prices for other household needs such as food, clothing, and shelter costs to name a few. In the 2007-2008 heating season, of the total $654,000 available ($300,000 plus /c
$354,000 as shown in item 1 above) $466,000 was required to meet the demand. /c

5) The Winter Warmth Program is consistently delivered across the Enbridge franchise area. The demand and amounts of relief can vary depending on the number of customers and the specific need of the communities. Anticipated participation is typically based on historical take up of the program.

Witness: Debbie Boukydis

unionGas
A Spectra Energy Company

October 8, 2008

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Consultation on Energy Issues Relating to Low Income Consumers
Information Requests
Board File No. EB-2008-0150

In response to the information requests made by members of the Ontario Energy Board, Board Staff and participants to the consultation meeting held from September 22 to 25, 2008, Union Gas Limited provides the following.

Disconnections

Union, on average, has approximately 215,000 residential, commercial and industrial customers in arrears each month. The disconnection notice, which is printed on the monthly bill, is based on the customer's number of days in arrears and amount of arrears.

The table below shows the annual number of disconnection notices printed on customer bills, and the number of customers that received notices.

	2008 *	2007	2006
Number of Bills with Notices	389,828	477,423	373,463
Number of Customers Receiving Notices	147,042	166,659	129,244

* 2008 is year-to-date - January thru September

The table below shows the annual number of residential service disconnections and reconnections within each year.

	2008 *	2007	2006
Number of Disconnections	21,241	28,281	25,297
Number of Reconnections	10,925	19,330	15,804

* 2008 is year-to-date - January thru September

Union's billing system does not track the reasons for account disconnections.

Security Deposits

The following table shows the number of residential customers, at year end, that have security deposits in place.

	2008 *	**2007**	**2006**
Number of Residential Deposits	99,073	93,123	91,565
Average Residential Deposit Amount	$271	$277	$267
Total Residential Deposits	$26.8 million	$25.8 million	$24.5 million

* 2008 is as of September 30, 2008

Residential deposits are applied to the account after 1 year of good payment history.

The following table shows the number of security deposits applied to disconnected accounts. These numbers do not include security deposits refunded to customers in good standing or applied to cover arrears that are less than the amount of the security deposit.

- For example, if a security deposit of $500 was applied to unpaid arrears of $450, there would be a $50 credit balance on the account which is then refunded to the customer.

	2008 *	**2007**	**2006**
Number of Residential Deposits Applied to Disconnected Accounts	1,554	2,759	2,798
Total Value of Residential Deposits Applied to Disconnected Accounts	$0.4 million	$0.9 million	$1.2 million

* 2008 is year-to-date - January thru September

Winter Warmth Program

1) How much each utility is spending on the Winter Warmth Program.

- Union Gas contributed $217,340 to the Winter Warmth program for the 2007-2008 heating season.

Total Budget – 2007-2008	$217,342
Administration Fees Paid	$ 16,133
Amount Paid to Applicants	$183,977
Rollover to 2008-2009 Winter Warmth	$ 17,232

2) Number of applicants per year.

- There were 623 applicants in 2007-2008 in the Union Gas service area.

3) The average grant per applicant.

- The average grant paid to applicants accepted for funding across the Union Gas service area was approximately $366.

4) The amount of money needed to meet the demand.

- Union Gas paid out nearly $184,000 in Winter Warmth grants in the 2007-2008 program year (net of the fees paid to agencies to administer the program). Some areas used up allocations within the first month, while others had funds remaining at the end of the program. Union re-evaluates the allocations each year to respond to the level of need in each community. In instances where there are funds remaining from an allocation made to a specific community, these allocations are rolled over into the Winter Warmth program in that community for the following season.

5) Is this information different in different geographic areas of your service area? If so, how?

- Demand and grant averages vary across the municipalities in Union's service area depending on historical levels of requests and need. For example, communities with higher population density and greater economic hardship typically have greater program take-up and receive higher allocations.

Should you have any questions, please do not hesitate to contact me.

Yours truly,

[Original signed by]

Patrick McMahon
Manager, Regulatory Research and Records

LOW-INCOME ENERGY NETWORK

Consultation on Energy Issues Relating to Low-Income Consumers

(EB-2008-0150)

September 22 – 25, 2008

THE ONTARIO TRILLIUM FOUNDATION
LA FONDATION TRILLIUM DE L'ONTARIO

What is the Low-Income Energy Network?

- LIEN is a network of anti-poverty, affordable housing and environmental groups.
- LIEN has over 75 member organizations, as well as individual and corporate supporters
- We seek to raise awareness of, and propose solutions to, energy poverty through:
  - outreach to community groups;
  - outreach to the public, e.g. through the media;
  - participating in OEB hearings and legislative processes;
  - working with policy-makers and local utilities to develop workable solutions to energy poverty.

LIEN Mission Statement

- The Low-Income Energy Network:
  - aims to ensure universal access to adequate energy as a basic necessity, while minimizing the impacts on health and on the local and global environment of meeting the essential energy and conservation needs of all Ontarians.
  - promotes programs and policies which tackle the problems of energy poverty and homelessness, reduce Ontario's contribution to smog and climate change, and promote a healthy economy through renewable and energy efficient technologies.

Presentation overview

1. Should the Board implement policies, programs or other measures designed to assist low income energy consumers?
2. Existing energy assistance programs
3. Low-income energy assistance programs in other jurisdictions
4. Rate measures to assist low income energy consumers.
5. Customer Service Issues (Payment Period, Disconnection, Security Deposits and Specific Service Charges) and Arrears Management Programs
6. CDM/DSM Programs for Low-Income Consumers
7. Time of Use Pricing; Sub-metering issues; energy retailers
8. Program Funding Mechanisms

Topic 1: Should the Board implement policies, programs or other measures designed to assist low income energy consumers?

- Energy poverty is a serious, systemic problem that can't be addressed with band-aid solutions
- The Board is responsible for regulating natural gas and electricity utilities
- The Board has a mandate to, and is responsible for setting just and reasonable rates
- Most low-income consumers buy "system gas" or "RPP electricity". For them, the OEB regulates 100% of the prices they pay and the bills they receive, and is in the best position to implement the needed assistance

Topic 1: Should the Board implement policies, programs or other measures designed to assist low income energy consumers?

- The Board has the relevant expertise to implement the policies, programs and other measures.
- Assistance directly from the government is more uncertain and less flexible. Certainty can be provided by the OEB and is needed for planning programs and flexibility is needed to respond to vagaries of weather and economics.
- Given that natural gas and electricity services are universal services, all customers should contribute to the assistance required by low-income consumers. There are many precedents for this.
- Low-income consumers need affordable rates. Win-win alternatives exist between customers and the utilities.

Broader context for conservation; Opportunities to end energy poverty

Environmental, social and economic…

- Ontario's goal to reduce peak electricity demand by 6,300 MW by 2025 (OPA's Integrated Power System Plan or IPSP – includes $10 Billion for conservation)
- Ontario's climate change plan (coal plant phase-out by 2014)
- Ontario's long-term affordable housing strategy
- Ontario's poverty reduction strategy, with firm targets to measure progress

Ontario's energy crisis

- Need to refurbish, rebuild, replace or conserve 25,000 MW of generating capacity by 2020 (more than 80% of Ontario's current electricity generating capacity).

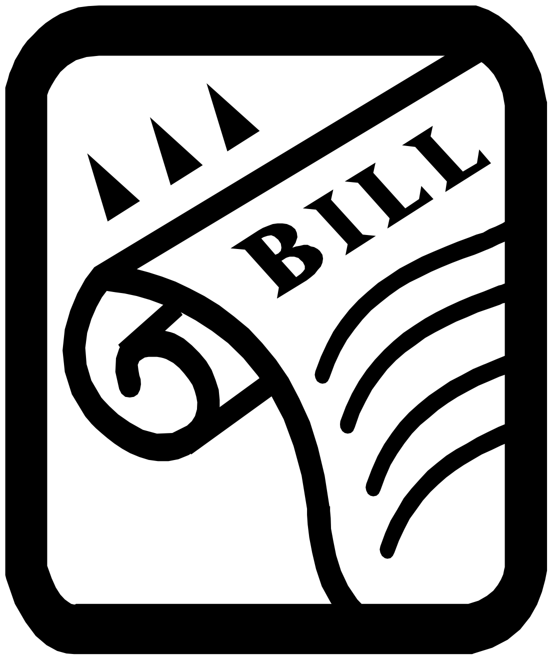
- OPA's IPSP - $60 billion infrastructure expansion and renewal over a 20-year period.

-$10 billion for conservation,
-$46 billion for new generation
-$4 billion on transmission

Rising energy prices

- Real cost-to-customer increases of OPA's 20-year IPSP expected to be 15% to 20%
- Natural gas prices and oil prices also on the rise

Rising energy prices and low-income consumers

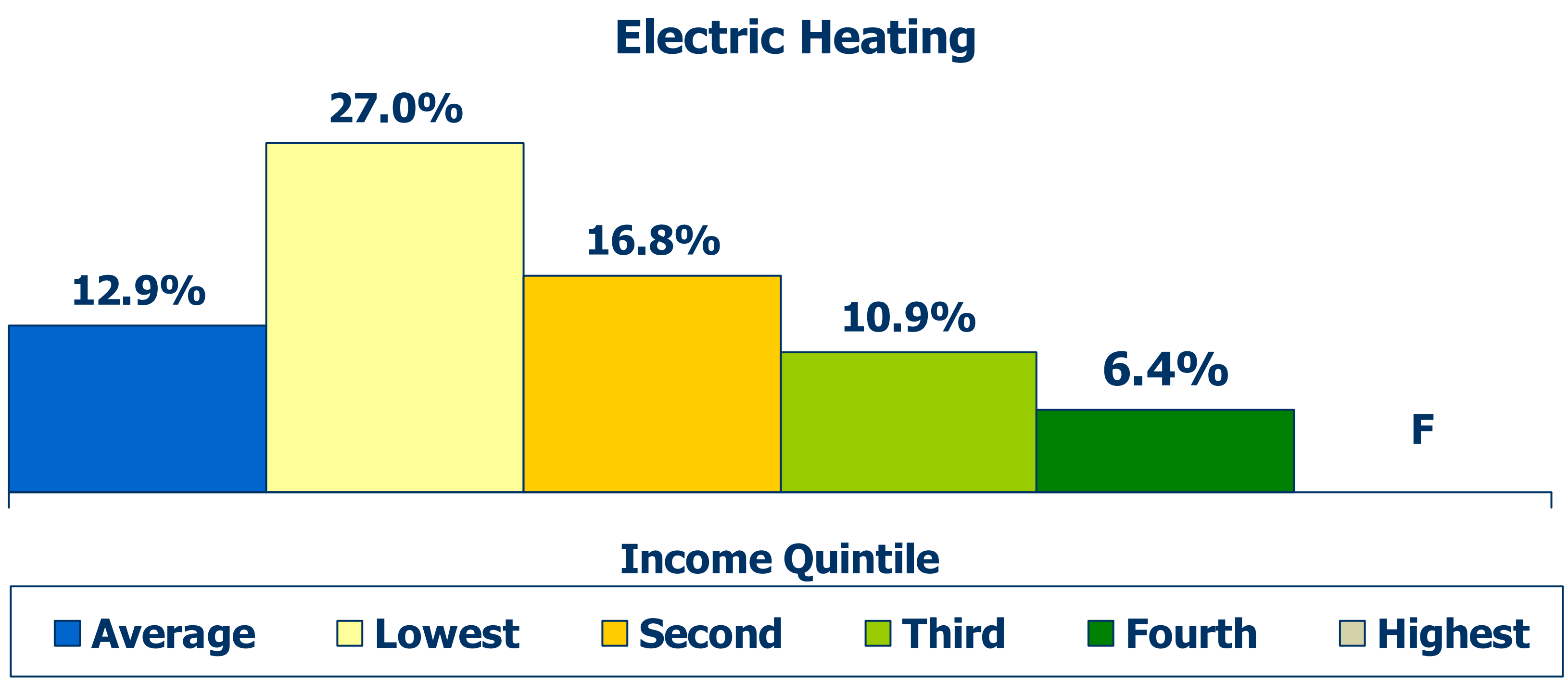


- Low-income households are particularly vulnerable to increases in shelter and utility costs - put housing in jeopardy.
- High energy costs are the second most significant reason for economic evictions in Ontario, right after unaffordable rents.
- Heating, eating or paying the rent will be choice faced by many.
- Reductions in energy use may be at the expense of health, socially acceptable standards of living.

Vulnerability to rising electricity prices

- The lowest household income quintile in Ontario has a far greater proportion of households that:
  - have electric heating as their principal heating equipment (27.0% compared to 12.9% for the average income household)
  - use electricity as principal heating fuel (30.8% compared to 16.7% for the average income household)
  - use electricity as principal heating fuel for hot water (39.3% compared to 26.4% for the average income household and 15.1% for the highest quintile).

Principal Heating Equipment



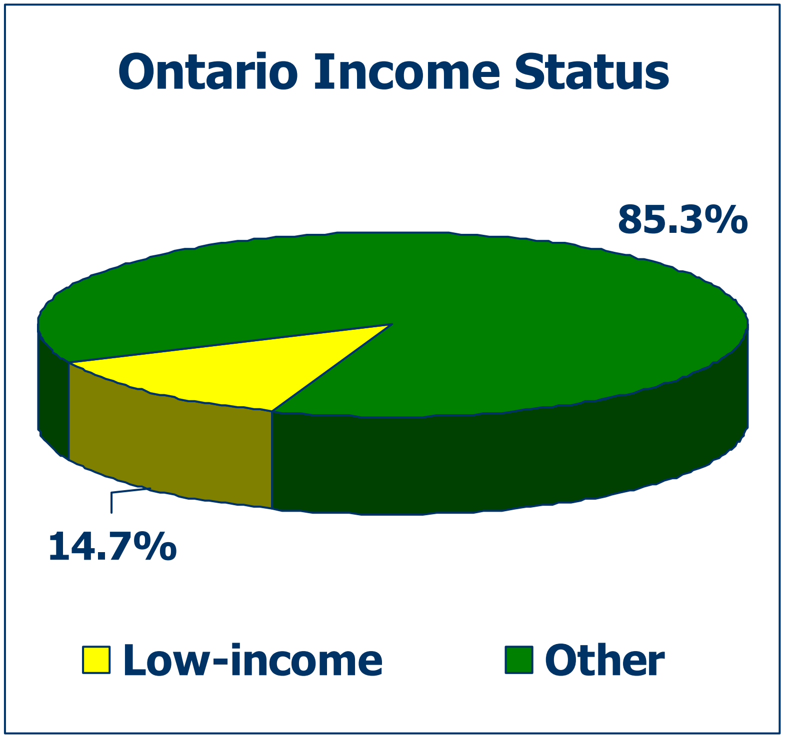
Source: Survey of Household Spending 2006, Statistics Canada

Energy use and the environment

- Electricity generating stations are big polluters.
  - 20% of greenhouse gases
  - 15% to 23% of smog-causing pollutants
  - Radioactive wastes we don't know how to deal with
  - 38% of electricity used by residential sector and apartments
- Home heating (electricity, natural gas and oil) responsible for 15% of greenhouse gas emissions in Ontario.
- Higher energy costs may spur conservation, BUT higher prices will increase the energy burden on low-income people who face barriers to accessing energy conservation/efficiency measures

Poverty

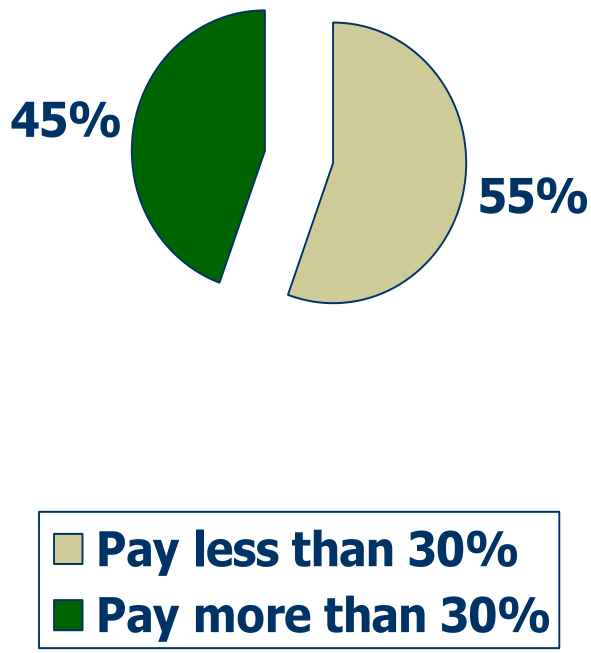
- 14.7% of Ontario's population (1,749,965 persons) are living at or below the "poverty line".
  - The majority of these persons live in tenant households, and in the private rental market



Source: Statistics Canada, 2006 Census of Population

Housing affordability and tenants

- 45% of Ontario's tenant households pay 30% or more of their household income on shelter costs (including utilities)
- 20% pay 50% and over of their household income on shelter costs - and are at risk of homelessness
- Impact of rising energy costs….



Low-income energy burden

- Low-income energy consumers face a disproportionate energy burden
- Energy burden refers to the amount of household income spent on energy
  - some experts say 6% is an affordable burden
  - U.K. fuel-poor household defined as spending more than 10%

Understanding Home Energy Burdens

Home energy burden =

Home energy bill / Household income

- Total shelter burdens affordable at 30% of income.
- Utility costs should be no more than 20% of shelter costs.
- Utility costs affordable at 6% of income

(20% x 30% = 6%).

Low-income energy burden

November 1, 2007 RPP - electricity bills for an average residential customer ranged from $92 to $140 per month.

- For a single mother with two children on social assistance, this represented 16% to 24% of her maximum shelter allowance of $595.
- For a single person working 35 hours a week at minimum wage ($8.00) this represented 8% to 12% of this worker's total monthly pre-tax income of $1213.33.

- The typical low-income family in Ontario has only a $200 "cushion" to buffer income interruptions or deal with unexpected expenditures.

Where do low-income consumers live?

759,590 LICO households (2001 Census)

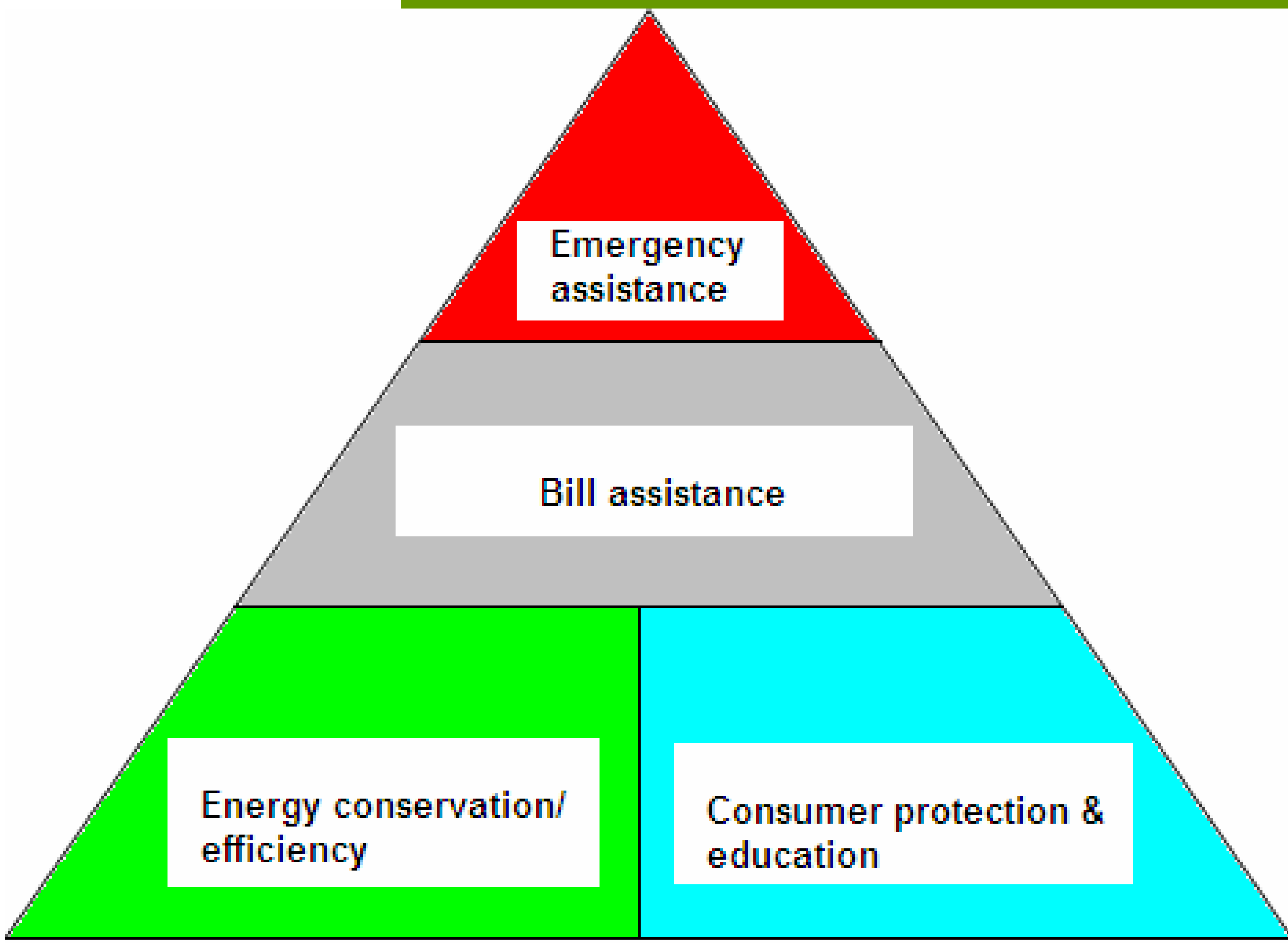
- 490,485 are tenant households (65%)
  - Live in social housing or private rental sector – most in multi-residential buildings
- 269,095 are homeowners (35%)
  - 39% are senior-led

SIMPLE SOLUTION

1. Affordable energy

2. Energy conservation

LIEN's approach to low-income energy conservation & assistance



What is needed

- A permanent low-income energy rate assistance program
- LIEN's proposal for an ***Ontario Home Energy Affordability Program*** has five major components: rate affordability, arrears management, crisis intervention, conservation and demand management, and consumer protections. It advocates that Ontario's low-income consumers should not be paying more than 6% of their total household income on energy.

Benefits of low-income energy efficiency program

- Lower energy bills for those least able to afford higher energy prices, as energy use drops by between 15% to 55%, depending on home and extent of measures
- Reduce poverty
- Reduce risk of homelessness
- Improve comfort/quality of life
- Reduce pollution, avoid building new expensive electricity generating plants

Benefits of low-income energy efficiency program

- Reduce demand for emergency assistance (public & charitable funds)
- Reduce costs to utilities associated with late payment or non-payment of bills (e.g. collection, disconnection, reconnection)
- Reduce costs to utilities associated with emergency calls
- Reduce need for public expenditures such as health, fire, building inspections, homeless shelters, and housing programs

Rising energy prices and low-income consumers

- Heating, eating or paying the rent will be a choice faced by many.

Ability to pay; just and reasonable rates

- Under the OEBA, the Board must approve or fix "just and reasonable rates"

- The Divisional Court has decided that the Board has jurisdiction to take ability to pay into account in setting rates

- The Board cannot deny this jurisdiction and refer the matter to be dealt with by Government

- The Board does not have an unfettered discretion - it must still produce just and reasonable rates

Ability to pay; just and reasonable rates

The Board must be guided by:

- ➔the public interest
- ➔ the protection of the interests of consumers with respect to prices and the reliability and quality of service

Unaffordable rates face low-income consumers with:

- ➔a choice between energy use against other essentials for normal living - a choice between "heating and eating"
- ➔disconnection of service

If rates are unaffordable, the goals of the public interest and protection of consumers are not served.

Topic 2: Existing energy assistance programs

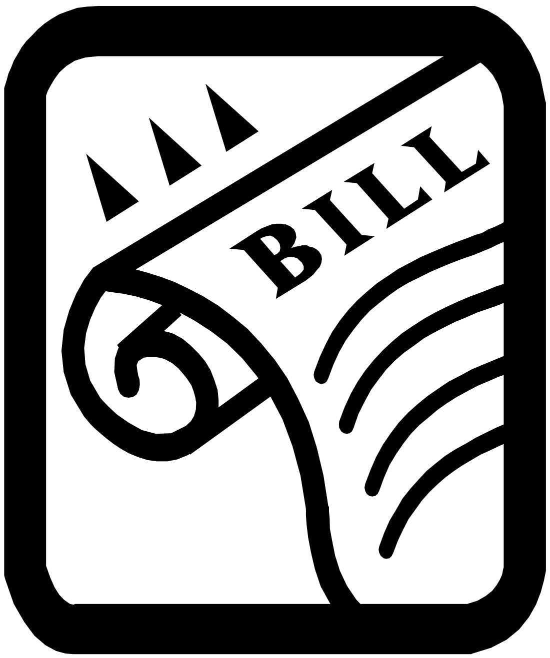
GAPS

- Patchwork of programs
- Differing eligibility criteria, application processes, and assistance levels
- Not available in all communities
- Don't provide enough money to solve the problem
- May be a grant or loan
- One-time funding only
- Funds tend to run out before the heating season is over
- Lack of awareness of existence of programs; lack of information
- Social stigma

Therefore, ill-suited to address permanent and widespread conditions of rising energy prices and income shortfalls

Topic 2: Existing energy assistance programs *continued…*

Rate assistance/emergency energy assistance



Emergency Energy Fund

- Provincial government announced "one-time" $2 million Emergency Energy Fund on March 29, 2004; renewed the fund in 2005 Ontario Budget, and annualized it; EEF doubled to $4.2 million in April 2006 (one-time)
  - *fund assists low-income households to pay energy arrears, security deposits and reconnection fees*

Topic 2: Existing energy assistance programs *continued…*

Rate assistance/emergency energy assistance

- **Shelter allowance**: Social assistance recipients who pay for heating costs directly can receive assistance for fuel costs as part of shelter allowance, up to a set maximum based on family size
- **Community Start-up and Maintenance Benefit (CSUMB)** pays for utility arrears, reconnections; maximum benefit can be accessed only once in 24-month period

Helping low-income consumers

Rate assistance/emergency energy assistance

- **Discretionary benefits** are available to assist OW/ODSP recipients with cost of utility arrears, deposits and reconnection fees

- **Share the Warmth, Winter Warmth** (Toronto Hydro & Enbridge Gas) and other charitable groups provide financial assistance to pay utility bills

Snapshot - low-income conservation programs

Enbridge Gas Distribution Inc.	$	4,558,250
Union Gas	$	4,303,000
LDCs' low-income CDM	$	4,293,120
LDCs' social housing CDM	$	4,554,216
OPA's Social Housing Program - Phase One	$	9,250,000
OPA's Energy Efficiency Assistance for Houses pilot	$	2,900,000
OPA's Canada-Ontario AHP Energy Efficiency Program	$	3,700,000
Total	$	33,558,586
OPA's Multifamily Buildings Program (6 units +)		RFP issued
OPA's Energy Efficiency Assistance for Houses program – expansion province-wide (5 units and under)		RFP issued

Utilities with Low Income and Social Housing Programs Implemented in 2005
(as reported by LDCs)

Low Income Measures

1. Aurora Hydro Connections Limited
2. Bluewater Power Distribution Corporation
3. Brantford Power Inc.
4. Centre Wellington Hydro Ltd.
5. Collus Power Corp.
6. EnWin Powerlines Ltd.
7. Guelph Hydro Electric Systems Inc.
8. Haldimand County Hydro Inc.
9. Hydro One Networks Inc.
10. Kitchener-Wilmot Hydro Inc.
11. Niagara Falls Hydro Inc.
12. Parry Sound Power Corporation
13. Peninsula West Utilities Limited
14. Port Colborne Hydro Inc.
15. St. Catharines Hydro Utility Services Inc.
16. Tillsonburg Hydro Inc.
17. Waterloo North Hydro Inc.
18. Wellington Electric Distribution Company Inc.
19. Whitby Hydro Electric Corporation

Social Housing Measures

1. Barrie Hydro Distribution Inc.
2. Enersource Hydro Mississauga Inc
3. Erie Thames Powerlines Corporation
4. Fort Frances Power Corporation
5. Hamilton Hydro Inc.
6. Hydro Ottawa Limited
7. London Hydro Inc.
8. Newmarket Hydro Limited
9. Oshawa PUC Networks Inc.
10. Powerstream Inc.
11. Toronto Hydro-Electric System Limited
12. Hydro One Networks Inc.
13. Kitchener-Wilmot Hydro Inc.

Helping low-income consumers

Energy conservation programs

- OEB encouraged LDCs to undertake low-income CDM, not mandatory
  - LIEN produced template for program for low-income homeowners and tenants who pay for utilities (electricity, gas) directly
  - Brantford Power piloted "Conserving Homes" program based on LIEN template

Helping low-income consumers

Energy conservation programs

- October 6, 2005 Minister's directive gives OPA/Conservation Bureau responsibility for low-income and social housing CDM - target of 100 MW reduction in electricity consumption and demand, or amount used by 33,000 homes
- OPA responsible for next phase of CDM programs through LDCs - $400 million over three years, beginning October 1, 2007

Helping low-income consumers

Energy conservation programs

- Social Housing Services Corporation (SHSC)
  - very motivated to reduce energy costs/consumption
  - Energy Management Program pilot and financing of retrofits
  - results from first phase audit of 5,000 units - $17.5 million needed for retrofits
- Discretionary benefits available for OW/ODSP recipients (homeowners or renters) to pay for pre-approved low-cost energy conservation measures
  - payment issued only once to benefit unit, may not exceed $50
  - for caulking, weatherstripping, insulating pipes, low-flow showerheads, CFLs, etc.

Helping low-income consumers

Energy conservation programs

- Federal government's 5-year, $500 million EnerGuide for Low-Income Households (EGLIH) program to assist 130,000 low-income households
  - some provinces (Saskatchewan, Newfoundland & Labrador) topped up EGLIH funding, piggy-backing additional energy conservation measures to achieve further energy reductions
- EGLIH <u>cancelled</u> by federal Conservative government in Spring 2006, along with EnerGuide program

Helping low-income consumers

Consumer protection

- Municipalities can pass Vital Services by-laws under Part VII of the *Tenant Protection Act*, but only a handful have
- these by-laws permit municipalities to step in to restore utility service in cases where tenants pay for the utility in their rent and the landlord has defaulted on payments
- a private member's bill has been introduced that provides for the provincial government to step in when there is no municipal vital services by-law in place

Topic 3: Low-income energy assistance programs in other jurisdictions

Low-income assistance can take many forms:

- Objectives of the program
  - Usage reduction
  - Rate Affordability

- Structure of the program
  - Rate affordability:
    - Percentage of income program (PIP)
    - Percentage of bill program (POB)
    - Discount (tiered, across-the-board)
  - Usage reduction:
    - Whole house
    - Base-load
    - Heating
    - Refrigerator replacement

Objectives of Low-Income Program

- Public health and safety
- Provide essential goods
- Efficient utility operations
- Provide least-cost service
- Prevent home energy insecurity
- Compensate for reverse subsidies

Forms of energy assistance programs in other jurisdictions: Ratepayer-funded programs

- **Fixed credit program**: New Jersey
  - Uniform statewide program
  - Gas and electric
  - Percentage of income based
  - Credits, not payments, "fixed"
  - Mandated by statute
- **Percentage of income program**: Ohio
  - Uniform statewide program
  - Made mandatory by Commission order.
  - Payments "fixed" as no greater than percentage of income.
  - Adopted under Commission inherent authority without statute.

Forms of energy assistance programs in other jurisdictions: Ratepayer-funded programs

- **Tiered discount program**: Indiana
  - Discounts vary based on income/resulting bill burden.
  - Adopted under Commission jurisdiction without statute.
  - Adopted by two natural gas utilities/not uniform statewide.
  - Participation based on LIHEAP enrollment
- **Straight discount program**: California
  - Mandated by statute.
  - Across-the-board 20% discount, not varying based on income (or bill burden)
  - Uniform statewide program (though outreach may differ by company)

Forms of energy assistance programs in other jurisdictions: Ratepayer-funded programs

- **Mixed program design**: Pennsylvania
  - Recommended: percentage of income or percentage of bill
  - If not PIP or POB, utility must show that it is at least as effective as PIP/POB
  - Adopted under Commission jurisdiction without statute.
  - Individual program designs, though within regulatory "guidelines" established by Commission.
  - Gas and electric utilities
  - Different utilities do different designs:
    - PECO: tiered rate discount
    - Multiple: Percentage of Income
    - Multiple: Percentage of Bill
    - Columbia Gas: Percentage of income (minimum average past payment).

U.S. experience: Impact on payments

- Payment are not “perfect” but are vastly improved.
- Payments measured in two ways:
  - Number of payments
  - “Payment coverage ratio” (payment / bill = coverage ratio)
- Experience shows:
  - Payments of payment-troubled customers are 10+ per year.
  - Payment coverage ratios are roughly 80 - 85% in Pennsylvania.
  - Payment coverage ratios are 90%+ in NJ.
  - As bill burdens increase, payment coverage ratios decrease.

U.S. experience: Impact on arrears

- Arrears are not eliminated, but are vastly reduced.
- Most difficult to change payment patterns of customers with historically high arrears.
- Payment patterns improve over time.
- Impact on arrears measured in three ways:
  - Number of accounts with arrears decrease.
  - Dollar levels of arrears decrease.
  - Seasonality of arrears leveled.
- Biggest impact on arrears are with those accounts having the highest arrears.

U.S. experience: Impact on collection activities

- The incidence of service terminations for nonpayment are dramatically reduced (70% or more).
- The intensity of collection contacts decrease:
  - While in past, collections may have progressed to point of a posted disconnect notice, under program, collections occur with mailed "reminder."
- Should not expect elimination (or even a reduction) in level of TOTAL collections activity.
  - By reducing collections toward low-income, utility can redirect collections toward other more productive accounts.
  - So, total collections remain the same, but are simply not attributable to low-income.

U.S. experience: Impact on revenues

- The financial impact on utility is not measured by amount of BILLINGS but rather on amount of RECEIPTS and at less cost of collection.
- **Indiana**: while program participants were BILLED 90% of what non-participants were billed, they PAID 111% of what non-participants paid.
- **Indiana**: both collection activity and low-income discounts reduced arrears. Low-income discounts reduced arrears more on a dollar-spent basis than did collection activity.
- Two conclusions: (1) low-income program can be revenue neutral (by increasing receipts even though reduced bills); and (2) low-income program can be more cost-effective in increasing receipts than the available collection alternative.

U.S. experience: Cost reductions

- There are cost offsets due to low-income program:
  - Bad debt decreases because payment responsibility for portion of bill is transferred to higher income households.
  - Bad debt decreases because low-income customers with more affordable bills pay better.
- Working capital decreases as arrears decrease.
- Customer service and collection expenses generally do NOT decrease, as customer service and collection activity simply transferred to other customers.
- Impacts on reduced expenses picked up in base rate cases.
  - Important to quantify only if there is a reconcilable rate rider to compensate utilities for program costs.

U.S. Experience: Usage Impacts

- No systematic usage increase has been found to occur as a result of a low-income affordability program.
- While no INCREASE usage occurs, programs tend to attract the highest use customers with which to begin (customers with low energy burdens choose not to participate).
- Two easy program mechanisms can be used to control usage:
  - An explicit connection between affordability program and usage reduction program, with high use participants referred to usage reduction.
  - A "fixed credit" program, which imposes cost responsibility for increased usage on customer, but allows customer to keep benefits of reduced usage.

Forms of Energy Efficiency Programs in other jurisdictions

- California – Low Income Energy Efficiency programs offered by electric and gas utilities
- Includes free weatherization, furnace repair or replacement
- Age, income, size of household and also disability form entitlement criteria

Energy efficiency – other jurisdictions, cont'd

- Connecticut – legislation requires delivery of low income residential programs
- Electrical programs delivered through community agencies; gas programs through a state Housing and Investment Fund for energy conservation loans and heating equipment upgrades

Energy efficiency – other jurisdictions, cont'd

- Illinois program since 1981
- 10 per cent of the benefits charge collected for the low-income energy assistance fund is provided for the low income weatherization assistance program
- Delivered through community agencies with priority to seniors and those with disabilities

Energy efficiency – other jurisdictions, cont'd

- Maryland - Columbia Gas Low Income Weatherization Program with Maryland Office of Weatherization
- Energy audits followed by weatherization; eligibility based on income and high gas usage

Energy Efficiency in other jurisdictions

- Massachusetts, Minnesota, Montana, New Jersey, New York and Oregon all also deliver low income energy efficiency programs

Topic 4: Rate-related measures and issues

- Not all low-income issues involve the design and implementation of a low-income "program."
- Many low-income issues involve the basic, historic process of setting cost-based rates.
- Due to the attributes of low-income customers, several issues arise with respect to basic rates and charges that relate to the imposition of undue burdens based on inattention to cost-causation.

Topic 4: Rate-related measures and issues: cost causality

- Cost causality means that the customer causing the costs should bear the costs. Conversely, if a customer does *not* cause the costs, he/she should not pay them.
- "Causation" is measured by a "but for" test: would the costs have been incurred but for the actions of the customer?
- Non-cost-based fees should be strictly scrutinized:
  - General customer service expenses should not be passed through in fees that disproportionately fall on low-income customers.
    - At the least, low-income should be exempt from such fees.
    - Disconnect/reconnect fees, collection fees, connection fees.

Topic 4: Rate-related measures and issues: basic rate structure

- Cost causality applies to the basic rate structure also, not just to fees.
- Inverted rate structure appropriate in an increasing cost environment.
- Cost-causation, however, means that:
  - appropriately sizing the first block is as important as getting the rate differential between blocks correct.
  - Seasonal rate differentials applied to the first block are rarely justified on a cost-causation basis.
  - Lost rate recovery/lost fixed cost recovery is rarely justified from the first block on a cost-causation basis.
  - Rate recovery of expensive peaking fuels/purchased power costs can rarely be justified from the first block on a cost-causation basis.

Topic 4: Rate-related measures and issues: the use of "price signals"

- Many economists argue that the rate structure should be used to send "price signals" to customers.
- The notion of "price signals" should not substitute for a rigorous analysis of the cost-causation relationship between charges and costs.
  - A non-cost-based charge cannot be justified on the basis of sending a "price signal."
- "Price signals" should be supported by data regarding:
  - The need for the price signal
  - The effectiveness of the price signal
- Consumer "price signals" are rarely effective for low-income customers.
  - Cannot control usage by "choice" without substantial investment.
  - Cannot afford to pay bills in the first instance.

Topic 4: Rate-related measures and issues: reciprocity of burdens and benefits

- The basics of cost-causation counsel that if a customer causes the cost to be incurred, that customer should pay the cost.
- There should be, however, a reciprocity in costs and benefits. The converse should be: if a customer causes a benefit to be incurred, that customer should reap that benefit.
- The reciprocal nature of the issue of "cost-causation" is frequently ignored. For example:
  - If low-income customers disproportionately contribute cash deposits, those customers should be allocated the benefit of the rate of return avoided by that customer-contributed capital.
  - If low-income customers disproportionately pay non-cost-based late fees, those customers should be allocated the revenue from those fees.
  - If low-income weatherization helps reduce bad debt and/or working capital, those avoided expenses should be captured and allocated back to additional weatherization.

Topic 4: Rate-related measures and issues: principles to be pursued

- The principle of cost-causation should be applied to miscellaneous customer service fees and charges as well as to basic rates.
- Cost-causation is measured by a “but for” test.
- Cost-causation may manifest themselves in non-price ways (e.g., size of initial consumption block).
- A rate based on “price signals” must be rigorously supported by evidence as to need and effectiveness.
- There should be reciprocity in “cost-causation.”
  - Benefits as well as burdens should be allocated back to the customers who “cause” them.

Rate affordability assistance: how does this issue of "cost-based rates" fit in?

- "Cost-based" is not a strict test. The term "costs" has many aspects to it:
  - Fully-embedded vs. marginal
  - Original cost vs. replacement cost
  - Long-run marginal cost vs. short-run marginal cost
  - Fixed costs vs. variable costs
- Cost subsidies have been used to promote social goals in the past:
  - Rural electrification promoted by rate averaging
  - Basic telephone service promoted by subsidies
  - Economic development promoted by fixed cost contribution theory
  - Carbon reduction promoted by "conservation incentive" rates.

Rate affordability assistance: how does this issue of "cost-based rates" fit in?

- Non-cost based rates approved when they are a BURDEN to low-income:
  - 1.5% per month late fees are not cost-based.
  - Deposits are not cost-based.
- Subsidy need not be cost-based if it is a PAYMENT (akin to rents).
  - Support of universal service a payment for grant of right of eminent domain.
  - Support of universal service a payment for grant of right to use public rights-of-way (e.g., streets, alleys)

Topic 5: Customer Service Issues and Arrears Management Programs

- Payment period
- Disconnection
- Security deposits
- Arrears management programs

Topic 5: Customer Service Issues and Arrears Management Programs

LIEN supports terms and conditions for utility service (e.g. consumer security deposit requirements, payment time-lines and plans, disconnection and reconnection policies, termination moratoria) that are in the best interests of low-income consumers, and:

- will not add to the service costs and penalize low-income consumers who are experiencing payment difficulties,
- will assist low-income consumers in accessing and maintaining essential utility service.

Payment options

- Low-income customers should be provided equal access to payment options meeting their needs.
- Payment periods:
  - Customers on fixed incomes may need to be able to specify the date on which they make payments (e.g., Entergy “pick-a-date” program) to ensure that payments are not due before income is received.
  - Customers using external payment centers should not be penalized for any lag in transfer and posting of payments.

Equal billing

- All distributors should offer equal billing plans to low-income consumers.
- In addition, equal billing should be available to low-income consumers who have enrolled with an electricity retailer. Community legal clinic clients have fallen into default on their electricity bills when they have switched to retailer supply because their equal billing option disappears.
- Credit history should not be a barrier to low-consumers enrolling in an equal billing plan since such plans will assist in reducing payment defaults.

Late payment fees

- Late payment charges that disproportionately and adversely affect low-income customers can be a barrier to accessing electricity service as they add to service costs and increase the risk of disconnection if low-income households are not able to make full bill payments.
  - Late payment charges cannot be justified as a "cost-based" fee.
  - Late payment charges cannot be justified as an "incentive" to pay, particularly for low-income customers.
  - Late payment charges cannot be justified as either "cost-based" or as an "incentive" for customers current on deferred payment plans.
- There should be a mandatory exemption or waiver of late payment charges for low-income consumers. A late payment fee waiver is also a component of the basic consumer protections in the LIEN proposal for a ratepayer-funded *Ontario Home Energy Affordability Program for Low-Income Households*

Disconnection

- An over-riding goal of LIEN's comprehensive strategy to address energy poverty is to pro-actively prevent service disconnections for low-income consumers who cannot afford to pay for their utility bills and other basic necessities.

- The establishment of a low-income rate affordability program will be a major step towards avoiding electricity disconnections for arrears.

Disconnection

- Crucial that LDCs' disconnection policies and procedures maximize the opportunities for low-income consumers facing service termination due to arrears to access emergency energy funds that they may be eligible to receive to prevent disconnection and/or restore service.
- This should be done in consultation and co-ordination with the relevant provincial ministries, municipal service managers, social service agencies and/or delivery agents.

Disconnection moratoria

- No service termination for low-income households in the heating and cooling seasons. OEB should protect against weather-induced death and illness.
- Other disconnection moratorium conditions should take into account age and medical conditions (households where infants and/or persons over 65 years of age reside, medically fragile)

Disconnection

- While the over-riding policy is to prevent the disconnection of service, the "threat" of disconnection can be as harmful as actual disconnection.
- Consumer protections are needed with respect to the use of disconnect notices:
  - Utilities should not threaten to disconnect in instances they do not intend to disconnect.
  - Utilities should not "over-notice" the potential of disconnections, as over-noticing leads to customers ignoring "legitimate" notices.
  - Utilities should not threaten a disconnection under circumstances where disconnection is not permitted (e.g., current on payment plan, protected by medical conditions, protected by severe weather moratorium).

Security deposits

There should be a mandatory exemption for low-income households from security deposit requirements which can adversely impact, or even exclude, these households from accessing energy.

- Other options – alternatives to cash security deposit, i.e. letter of guarantee/letter of credit
- OEB has set guidelines for collection of deposits, including payment by instalments

Arrears management programs

- LIEN's proposal for a ratepayer-funded *Ontario Home Energy Affordability Program for Low-Income Households* also includes an arrearage management program comprised of the following components:

- Arrears are to be retired over a two-year period;
- Customers are to make co-payments toward their arrears;
- Co-payments are to be set equal to an affordable percentage of income (1% per year);
- No pre-condition is established for the grant of arrearage management credits; and
- The appropriate response to non-payment is to place the program participant in the same collection process as any other residential customer.

Topic 6: CDM/DSM Programs for Low-Income Consumers

What is needed:

- Permanent, adequately-funded energy conservation programs for low-income consumers, with targets for the number of homes to be retrofitted annually.
- Such programs should be available at no cost to eligible participants and be equitably accessible province-wide.

Energy conservation and low-income consumers

Conservation is a cheap, fast, clean solution to energy crunch and climate change crisis

More efficient use of energy:

- reduces pollution major respiratory health improvements especially for youngest and oldest
- avoids cost of new generating plants
- reduces energy bills and lessens effect of rising prices
- makes housing more affordable & comfortable

BUT, it won't happen in low-income residential sector without financial investment **...**

CDM/DSM measures

- To achieve deep reductions in energy use, fuel-neutral programs should have a wide suite of measures (draftproofing, insulation, heating equipment upgrades) and be tailored to distinct low-income consumer groups: homeowners, tenants in private rental housing, and tenants in social housing.

Why is tenant involvement important?

- Deep reductions in energy use through energy efficiency will not be fully realized if there isn't a concurrent energy conservation education program to help shift tenants behaviour
- The best way to deliver an energy conservation program to low income tenants is by having low tenants design and deliver the energy conservation program

Why is tenant involvement important?

- Tenants can identify unforeseen opportunities and challenges in energy saving programs because they know their situation better than any of us.
- Tenant leaders set a good example and teach fellow tenants about saving energy – this results in real behaviour changes
- What motivates tenants to save energy will vary by situation, but we know it's not always about saving money!

Tenant-led energy saving programs exist

- Brahms Energy Savings Team (BEST) and Walpole is Reducing Energy (WiRE) were two successful tenant-led energy conservation programs run in TCHC neighbourhoods (2005, 2007).
- Low Income Tenant Energy Savers (LITES) is engaging tenants living in private high rise buildings in both Ottawa and Toronto
- The City of Toronto supports community-led conservation programs and it is being realized through Live Green Toronto

Important Program Principles

- Free for tenants to participate
- Open to everyone in the building, regardless of income/benefits.
- Tenants help design and deliver the program
- Peer education (tenants teaching tenants)
- Offers tools and materials that enable tenants to start saving energy right away (e.g. power bars, light bulbs, etc.)
- Supportive landlord who will ‘do their part’ (appliance replacement, retrofits, maintenance)

Brahms Energy Savings Team (BEST)

- 342 units and about 850 tenants (350 of whom are children)
- hired and trained six tenants from the buildings as community education and outreach workers (or Animators).
- Animators designed and delivered an energy education program that engages their fellow tenants in their primary language (English, Farsi, Somali, and Tamil) and in culturally appropriate ways.
- 75% of households participated
- 6.6% in energy reduction annually
- won 2006 Green Toronto Award for best community project

Walpole is Reducing Energy (WiRE)

- Downtown east end, 118 units
- 3 animators delivered the program
- WiRE reached 85 households
- 90% found the material easy to understand and use
- 87.5% said they learned new things
- 87.5% felt they saved money as a result of the WiRE Program
- 96.4% also said they were more comfortable

Low Income Tenant Energy Savers (LITES)

- Saving Energy: The 6-Step Guide to Tenant Action
- Regional Workshops – Toronto, Ottawa, Windsor
- 2 Tenant-led Energy Conservation Programs in private high rise buildings
  - 2 apartment buildings in Ottawa (owned by TransGlobe)
  - 2 apartment buildings in Toronto (owned by CAP REIT)

DSM for Low-Income Consumers in Ontario

- Low-income housing is also older and more in need of maintenance than the Ontario average, implying there are significant energy efficiency gains to be made
- Low-income households have fewer appliances than the average home, although these appliances and heating systems in low-income housing are older than the average, and hence less energy efficient

Access and control issues

- Much of the energy burden of low income consumers is "inelastic"
- Examples include heating, water heating, lighting, and basic appliances such as refrigeration
- Low income consumers lack control or access to capital in terms of building envelope, insulation, weatherization, efficient appliances

Characteristics of low-income dwellings

- More likely to be space heating
- More likely rented
- More likely spending relatively more on basic energy needs than higher income quintiles

Household equipment

- 27% of the lowest household income quintile have electric heating as their principal heating equipment (compared to 12.9% for the average income household)
- 62.6% of lowest income households had principal heating equipment over 10 years old (compared to 48.3% in highest income households)
- 39.3% heated hot water with electricity in lowest income quintile, compared to 15.1% in highest quintile
- The age of heating equipment also implies efficiency and cost differences in absolute terms
- Impacts of these differences on lowest income households are disproportionate

Types of low-income energy efficiency programs

- Energy audits
- Weatherization including weather stripping, caulking, attic insulation, storm windows
- Appliance replacement, particularly refrigerators
- Furnace repair or replacement
- Fuel switching (e.g. electrical space heating to natural gas, propane or oil in Vermont)

Societal benefits of low-income DSM

- Participation in energy savings and climate change
- Significant component of residential energy use
- Avoidance of energy cost mobility and improved educational outcomes for youth

Societal benefits of low-income DSM cont'd

- Reduced need for public expenditures on health, fire, housing and homeless shelters
- Reduced emergency calls to utilities
- Reduced utility costs re collection, termination, reconnection
- 17 to 300 percent "benefit adder" cited*

Topic 7: Time of Use Pricing; Sub-metering issues; energy retailers

Energy Retailers:

- Addressing issue of early termination fee for vulnerable low-income households under certain conditions

Who’s calling for Smart Meters, sub-Metering?

Ontario government

- have facilitated expansion of Smart Meter initiative to condominiums and multi-residential rental sectors to reduce electricity peak demand

Landlords

- want to transfer in-suite utility costs directly to tenants

Suppliers

- Smart sub-metering providers see business opportunity in multi-residential rental sector

Smart Meters; sub-metering

Smart meters

- Record how much, and at what time of day, electricity is used (unlike current mechanical/analog meters)

Sub-meters

- Installed behind master or bulk meters; measure electricity consumed in-suite in order to individually bill tenants. Electricity sub-meters can also be smart meters.

Smart sub-metering

- Landlord with bulk meter is the customer of the electricity LDC; smart sub-metering provider, acting on behalf of the landlord, issues bills to each tenant household in the building for in-suite consumption; collects payments and remits to landlord

How many tenants; where do they live?

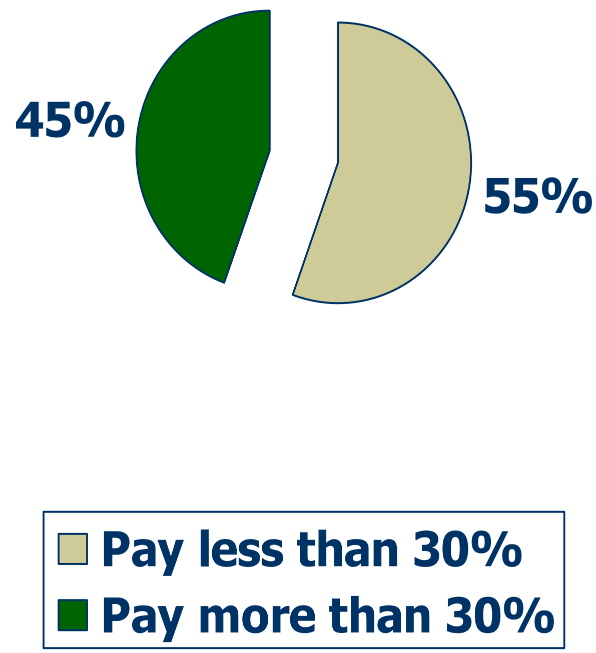
- 28.8% of all Ontario households are renters (1,312,295 tenant households)
  - 40% live in apt. buildings with five or more storeys
  - 29% live in apt. buildings with fewer than five storeys

Housing affordability and tenants

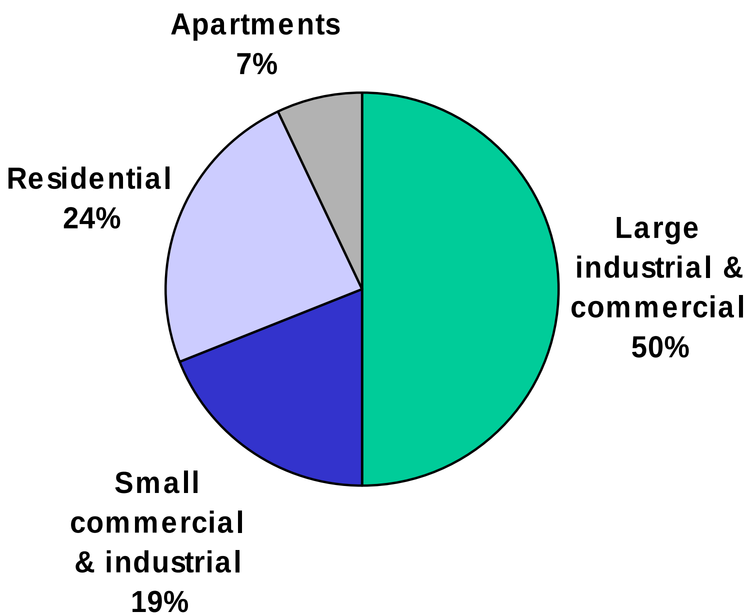
- 36% of Ontario's tenant households are living at or below the "poverty line" (2001 Census)
- The median income of Ontario's renter households is less than half of homeowner households ($33,447 vs. $74,712) – 2006 Census
- Ontario renter households represent 31% of all Ontario households, but comprise 66.4% of Ontario households in core housing need (2001 Census)

Housing affordability and tenants

- 45% of Ontario's tenant households pay 30% or more of their household income on shelter costs (including utilities)
- 20% pay 50% and over of their household income on shelter costs - and are at risk of homelessness
- Impact of smart sub-metering....



What percentage of electricity use in Ontario is from apartments?



- Our best estimate is that bulk-metered apartments, i.e. those that are candidates for sub-metering, comprise only 7% of Ontario's annual electricity consumption

Tenants and electricity use

Currently:

- most tenants in multi-residential private rental sector pay for utilities in their rent
- estimated that 85% to 90% of multi-residential buildings are bulk-metered, and most Ontario apartment buildings are not electrically heated
- most social housing tenants pay for utilities in their rent; only 18% of tenants pay electricity bills directly

Conservation does matter for tenants

- It's their home
- They pay for utilities – either in rent or directly
- They pay when landlords apply for above-guideline rent increases for "extraordinary" increases in utilities costs, or for capital expenditures for energy (or water) conservation work
- They are affected by climate change
- Their early engagement is essential for maximizing energy savings

Conservation does matter for landlords

- Utility prices are rising, increasingly volatile operating cost
- Need to maintain and environmentally retrofit their buildings to protect their assets and to ensure ongoing marketability, minimized vacancy loss
- They are affected by climate change
- Their early engagement is essential for maximizing energy savings

Who will get a Smart Meter?

- Original target was to install 4 million smart meters for all Ontario customers (residential) by 2010 at a cost of $1 billion
- Interim target of 800,000 meters in homes and small businesses by 2007
- "smart metering initiative" now means equipping each household in Ontario with a smart meter over time

Who will get a Smart Meter? cont'd

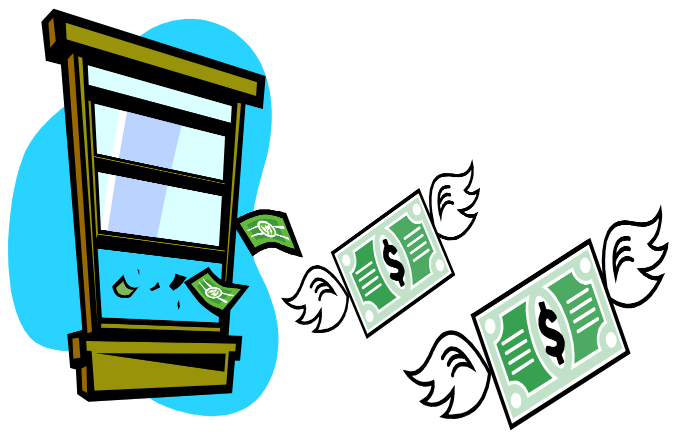
- government had been unclear on whether individual Smart Meters would be installed in each apartment and condo unit in the province
- initiative now includes condos (Bill 21, *Energy Conservation Responsibility Act, 2006)* and rental sector (Bill 109, *Residential Tenancies Act, 2006)* – *voluntary, not mandatory*
- Condo smart metering & smart sub-metering regulations in effect as of December 31, 2007; OEB has issued Smart Sub-metering Code and is licensing smart sub-metering providers

Is Smart Metering the answer, effective conservation?

- intended to encourage consumers to shift electricity use to off-peak hours
- BUT, low-income households have least capacity to shift energy use (families with children, seniors, disabled, unemployed)

If tenants pay directly for in-suite energy use, will they will use less?

- Landlord controls building envelope (windows, insulation), HVAC systems, appliances such as fridges
- Tenants control discretionary energy use in-suite
- Both impact on energy use reduction efforts



If tenants pay directly for in-suite energy use, will they will use less?

- Smart sub-metering energy savings claims vary – 10% to 40%, 15% to 25%, average of 25% to 33% - but, no expert, neutral study undertaken to date with detailed analysis of how smart sub-metering savings are being achieved
- Study should include cost-benefit analysis of sub-metering vs. energy efficiency retrofits vs. energy conservation education and examine:
  - the characteristics of the buildings and individual units where smart sub-meters are installed,
  - who is or is not achieving energy savings and why, and
  - the impact on housing and financial security of the residents

If tenants pay directly for in-suite energy use, will they will use less?

110-unit building in Toronto – smart sub-metered

- **41% of units paid more** (reduced rent + electricity bill), 12% paid same, **47% paid less**

- According to a sub-metering company, in multi-unit buildings:
  - 70% of residents use 50% of electricity (low users)
  - 20% of residents use 25% of electricity (medium users)
  - 10% of residents use 25% of electricity (high users)

Split incentive between landlords and tenants

- landlords want to minimize costs and make a profit; tenant seeks safe, comfortable, affordable home
- tenants don't have authority to invest/retrofit – or financial resources
- Smart sub-metering shifts financial incentive to provide and maintain an energy-efficient building & appliances for tenants – could undermine conservation efforts

Energy efficient fridges

- refrigerator replacement was the 2nd most recommended energy-saving measure in SHSC's Green Light initiative energy audits
- In 1990, refrigerators larger than 16.4 cu.ft. used more than 1000 kWh annually on average – cut in half by 2003

Smart sub-metering & tenants

- Part VIII, sections 137 and 138 of *Residential Tenancies Act, 2006– still to be proclaimed, regulations to be developed*
  - Landlords <u>may</u> install Smart Meters <u>without sitting tenant consent</u>; transfer electricity costs directly to tenants, outside of rent
  - Provisions for rent reductions and energy conservation obligations on landlords to be worked out in regulations

Smart sub-metering & tenants

- Currently, smart sub-metering activity taking place under section 125 of the RTA
- requires **consent** of sitting tenant before landlord can transfer the cost of electricity use to the tenant directly and decrease rent; proceeding without consent, landlord may be subject to a fine of up to $10,000 under RTA section 31(1)
- if sitting tenant does not consent, landlord may rent unit without utilities on turnover

Smart sub-metering & tenants

Lease agreement clause – consent??:

- *"The Tenant also acknowledges that where hydro is currently included in rent the Landlord, in its sole discretion, may at anytime chose to meter the Tenant's rented premises separately and transfer responsibility for payment of hydro directly to the Tenant based on the Tenant's own consumption. In such an event, the Landlord shall reduce the monthly rental in accordance with applicable Rent Control Legislation and the Tenant hereby consents to such transfer or responsibility for payment of hydro."*

- These clauses may not be legal.

Effective conservation & fairness

- Crafting of the regulations under Part VIII of the RTA will be crucial to ensuring that:
  - the energy conservation obligations on landlords will be those most effective in reducing energy consumption/costs for tenants, <u>and</u> in helping to meet province's conservation goals
  - the rent reduction after tenants take on the in-suite utility costs will be calculated fairly

Topic 8: Program Funding Mechanisms

- Ratepayer-funded
- Stability, predictability
- Equitable
- Incorporated in whole cost of system
- Burden of a very expensive system otherwise very inequitably borne by the most vulnerable

Rate Assistance: Funding through rates the most reasonable way to support low-income programs

- Legislative support is not the most appropriate way:
  - Legislative funding is uncertain (makes program planning impossible).
  - Legislative support is inflexible.
    - If prices go up, legislature cannot respond. If weather is severe, legislature cannot respond.
    - If prices go up, weather is severe, rate-based assistance automatically goes up as sales volume goes up (and vice versa).
- Legislature support involves no reciprocity. The public provides all the support, but the utilities keep all the benefits from reduced costs.

Rate Assistance: 4 different ways to collect a “system benefits charge”

- A straight per meters basis (e.g., Illinois)
- A straight volumetric basis founded on a per unit of energy (e.g., Maryland, New Jersey)
- A volumetric basis founded on a percent of revenues (e.g., Maine)
- A mixed volumetric/per meters (allocate between customer classes volumetrically but collect within customer class on a per meter basis) (e.g., Colorado).

Rate Assistance: It is appropriate for ALL customer classes to contribute

- The nearly universal rule is that all customer classes contribute (NH, ME, NJ, MD, OH, IN, MN, UT, CO, AZ, CA)
  - Only Pennsylvania allocates exclusively to residential (that decision is subject to court review).

Rate Assistance: It is appropriate for ALL customer classes to contribute

- From a policy perspective, it is appropriate to charge all customer classes:
  - Universal service is a "public good" that should be paid by all.
  - Universal service yield public benefits that benefit all customer classes (e.g., consider economic development impacts; reduced health care costs; impact of more affordable housing on employee recruitment and retention).
  - Universal service yields direct benefits to all customer classes (e.g., consider wage supplements for low-wage employers).
  - No single customer class "causes" need for universal service. Nonparticipating residential ratepayers no more cause universal service costs than do nonparticipating commercial/industrial ratepayers.

Usage Reduction: Program Funding – precedents in other jurisdictions

- Low income DSM programs offered to eligible participants free of charge
- One model: proportion of rates collected
- Another model: A Universal System Benefits Charge (e.g. Montana)
- May be supplemented by additional sources: federal or state/ provincial governments; grants and donations including in-kind

Usage Reduction: Precedents cont'd

- **Vermont**: statewide provider, Efficiency Vermont is funded by an energy efficiency charge on electric bills while the gas programs are funded by a variety of funding sources
- In **Oregon**, DSM budgets are embedded in rates, including low income programs mandated by the state.

Usage Reduction: Precedents cont'd

- **New York** provides electric efficiency program including for low-income customers under a systems benefits charge.
- **New Jersey** has a Societal Benefits Charge created by legislation which is aimed at improving energy affordability through energy efficiency measures.

Usage Reduction: Precedents cont'd

- **Montana**'s weatherization program is funded by a Univeral System Benefit Charge, also legislated by the state
- **Minnesota** allocates a percentage of state revenues for gas and electric utilities to energy conservation improvement which is required by law and includes low income programs

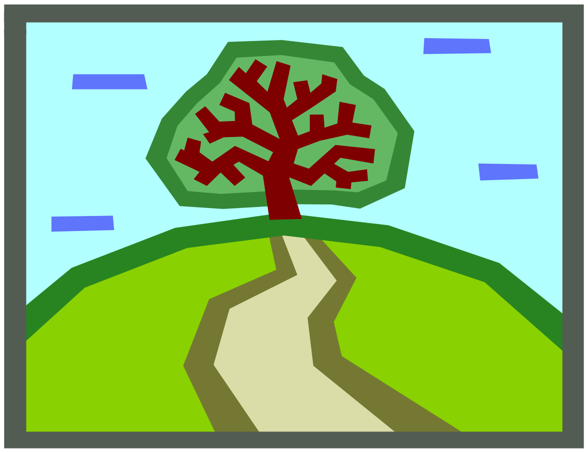
Usage Reduction: Precedents cont’d

- **Maryland**’s Electric Universal Service Program assists low income customers with their electric bills; most of the funding comes from industrial and commercial customers with the remainder from residential customers at 40 cents per month.
- **Illinois** administers a monthly systems benefit charge of .40 on residential gas and electric accounts, and higher amounts on commercial and industrial accounts for a state fund for low income energy efficiency

Usage Reduction: Precedents cont'd

- **Connecticut** administers a system benefits charge for energy efficiency on all electricity sold in the state; a portion is spent on low income energy efficiency
- **California** obtains funding for its low income energy efficiency programs, both gas and electric, from a system benefits charge on customers bills.

Going Forward



- OEB needs to initiate a generic hearing on a low-income rate affordability program
- Province-wide low-income CDM/DSM programs that provide deep reductions in energy use

				Provinces / Territories														Funding Sources					Customer Eligibility Requirements										How is Assistance		
Programs	Sponsor(s)	Program Type	Program Description	Ontario	Quebec	Nova Scotia	New Brunswick	Manitoba	British Columbia	Prince Edward Island	Saskatchewan	Alberta	Newfoundland and Labrador	Yukon	Northwest Territories	Nunavut	Funding Level	Ratepayers (Voluntary / Mandatory)	Provincial Tax / Surcharge	Federal / Provincial Grants	Charitable Contributions	Other	Families (National Child Benefit)	Seniors (Guranteed Income Supplement)	Income Level	Poverty Level	Disabled / Medical Condition / Need	Other	Security Deposit	Reconnection Fee	Arrearage	Other	Fixed Amount	Other	Source(s)
ecoENERGY Retrofit for Homes	Government of Canada	Energy Efficiency	In January 2007, the federal government introduced the ecoENERGY Initiative to help Canadians use energy more efficiently, boost renewable energy supplies and develop cleaner energy technologies. ecoENERGY Retrofit for Homes provides home and property owners with grants of up to $5,000 to offset the cost of making energy-efficiency improvements. Only homes that have undergone a residential energy efficiency assessment by an energy advisor licensed by Natural Resources Canada will be eligible for grants. The ecoENERGY Retrofit grant is based on the type and number of energy improvements that have been made, and how much the efficiency of the home has been improved. The grant is based on how effective that upgrade is in saving energy, not on the cost of the upgrade. The maximum grant one can receive per home or multi-unit residential building is $5,000; whereas the total grant amount available to one individual or entity for eligible properties over the life of the program is $500,000.	X	X	X	X	X	X	X	X	X	X	X	X	X																Grants for energy efficiency improvements up to $5,000		Grants for energy efficiency improvements up to $5,000	"ecoENERGY Retrofit - Homes." ecoACTION - ecoENERGY. June 2008. Government of Canada. 13 August 2008 <http://ecoaction.gc.ca/ecoenergy-ecoenergie/retrofithomes-renovationmaisons-eng.cfm>
Residential Rehabilitation Assistance Program (RRAP) for Homeowners	Canada Mortgage and Housing Corporation	Loan forgiveness	Financial assistance to low-income homeowners for mandatory home repairs that will preserve the quality of affordable housing. The program helps people who live in substandard dwellings and cannot afford to pay for necessary repairs to their home. Homeowners may qualify for assistance if your property is eligible and if your total household income is at or below the Income Threshold set by CMHC. In general, mandatory repairs related to heating, structural, electrical, plumbing and fire safety are eligible for funding under Homeowner RRAP. Assistance is in the form of a fully forgivable loan. The loan does not have to be repaid if you agree to continue to own and live in this hous during the earning period, which could be up to five years (the loan forgiveness period). The amount you could receive is based on the cost of mandatory repairs and the area in which you live.	X	X	X	X	X	X	X	X	X	X	X	X	X									X							Fully forgivable loan		Loan based on cost and geographic area	"Homeowner Residential Rehabilitation Assistance Program - Homeowner RRAP." CMHC - Programs and Financial Assistance. August 2008. Canada Mortgage and Housing Corporation. 13 August 2008 <http://www.cmhc.ca/en/co/prfinas/prfinas_001.cfm>
Emergency Repair Program (ERP)	Canada Mortgage and Housing Corporation	Contribution	Financial assistance to help low-income households in rural areas, for emergency repairs required for the continued safe occupancy of their home. Only those repairs urgently required to make a house safe are eligible for assistance. Examples include: heating systems; chimneys; doors and windows foundations; roofs, walls, floors and ceilings; vents, louvers; plumbing; and electrical systems. Assistance is in the form of a contribution which does not have to be repaid. The maximum contribution varies according to the cost of the repairs and geographic zone in which the property is located.	X	X	X	X	X	X	X	X	X	X	X	X	X									X							Grant		Grant based on cost and geographic area	"Emergency Repair Program (ERP)." CMHC - Programs and Financial Assistance. August 2008. Canada Mortgage and Housing Corporation. 13 August 2008 <http://www.cmhc.ca/en/co/prfinas/prfinas_005.cfm>
Emergency Energy Fund	Ministry of Community and Social Services	Emergency Assistance	Allocates monies to low-income facing energy-related emergencies. The fund is used to pay for utility arrears, security deposits and reconnection costs for electricity, natural gas, oil and other forms of energy.	X																X					X				X	X	X				"FAQs: Natural Gas." Oil and Gas: Frequently Asked Questions. September 2005. Ontario Ministry of Energy and Infrastructure. 13 August 2008 <http://www.energy.gov.on.ca/index.cfm?fuseaction=oilandgas.faqs&subtopic=naturalgas> "Energy assistance funds for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
Energy Efficiency Program for Houses (Single Family Homes) / Ministry's Low Income CDM Initiative	Ontario Power Authority	Energy Efficiency	Objectives of the program: (1) Achieve energy consumption and demand savings in low-income single family homes to support the 100 MW Low Income and Social Housing Directive; (2) Create awareness among low-income households and their support networks about the benefits of energy conservation; and (3) Establish effective channels for the delivery and implementation of Conservation Demand Management programs sensitive to the needs of the low-income community. The 100 MW Low Income and Social Housing Directive is designed to reduce overall electrical energy consumption and demand by residents of low-income and social housing by up to 100MW; also expected to result in longer-term reductions in electricity peak demand, particularly by reducing the use of inefficient appliances.	X																					X										"Housing Initiatives." OPA Initiatives. Ontario Power Authority. 13 August 2008 <http://www.powerauthority.on.ca/Page.asp?PageID=751&SiteNodeID=406> Minister of Energy, "Conservation and Demand-Side Management Initiatives (Residents of Low-Income and Social Housing)." Memorandum to Ontario Power Authority, dated October 2005.
Multi-Family Building Program	Ontario Power Authority	Energy Efficiency	Objectives of the program: (1) Reduce, by 2010, the multi-family building sector's contribution to the electricity needs of the electricity system for summe peak demand by at least 100 MW and overall energy consumption by 385 GWh/yr; (2) Reduce the energy burden imposed notably on low income residents and their housing providers and/or building owners, managers, and operators; (3) Promote sustainable, comprehensive, 'building as a system' energy management initiatives in which buildings are regarded as an integrated whole with interactions among energy efficient measures within a project that can affect the building's overall energy efficiency performance; (4) Integrate multi-family building conservation projects with other OPA initiatives. For examples, OPA demand response, distributed generation, renewable energy; (5) Raise the level of energy awareness through education; and (6) Promote the culture of conservation within the multi-family sector.	X																					X										"Housing Initiatives." OPA Initiatives. Ontario Power Authority. 13 August 2008 <http://www.powerauthority.on.ca/Page.asp?PageID=751&SiteNodeID=406>
Enbridge Home Weatherization Retrofit Program	Enbridge Gas	Energy Efficiency	The Enbridge Home Weatherization Retrofit program provides income-eligible participants in the GTA with a free home energy assessment and weatherization upgrades at no cost, to improve the energy efficiency of their home. Program participants can save between 15 to 75% on their monthly gas bills. Green$aver will conduct a thorough energy assessment and use the assessment to identify cost-effective energy efficient recommendations to implement, including draft-proofing and insulation. Green$aver will also be responsible for implementing the measures in each home with their experienced retrofit crews. Approximately 300 qualifying low-income Enbridge Gas customer households will benefit from this pilot program.	X																			X	X	X		X								"Enbridge Home Weatherization Retrofit Program." Energy Audits - Energy Efficiency Assistance Program. GreenSaver. 13 August 2008 <http://www.greensaver.org/audit_eeaph.html> "Financial Assistance." Enbridge Gas Distribution. July 2008. <https://portal-plumprod.cgc.enbridge.com/portal/server.pt?space=CommunityPage&control=SetCommunity&cached=true&CommunityID=587&PageID=0>
Enbridge Enhanced TAPS Program	Enbridge Gas	Energy Efficiency	The Enhanced Thermostat, Aerator, Pipewrap, Showerhead (TAPS) Program is available at no cost to qualifying low-income families and individuals through to December 31, 2008. The following energy efficiency measures are supplied and installed: programmable thermostat, low-flow showerheads, and hot and cold water pipe wraps. Kitchen and bathroom aerators are provided for recipients to install themselves.	X																					X										"Free energy efficiency/ conservation programs for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
Union Gas - Helping Homes Conserve	Union Gas	Energy Efficiency	Union Gas has developed a free energy efficiency and conservation program, "Helping Homes Conserve", targeted at low-income homeowners and low-income tenants who pay for their energy bills directly and are Union Gas customers. Low-income participants will benefit from the free installation of an Energy Saving Kits (which contain up to 2 low-flow showerheads, two faucet aerators, and pipe insulation) and the free installation of a programmable thermostat. Customers must have a natural gas water heater to qualify for the ESK installation, and a natural gas furnace to qualify for the programmable thermostat installation.	X																					X										"Free energy efficiency/ conservation programs for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
Community Start-Up and Maintenance Benefit (CSUMB)		Rate Assistance	CSUMB is for people who qualify for social assistance and are about to lose their housing because they owe rent or utility payments. To prevent a utility or heat disconnection, CSUMB may be issued to a recipient who has received a notice to disconnect due to utility or energy arrears. In addition, CSUMB may b issued to pay for utility or energy reconnection costs where the utility or energy was disconnected due to arrears. In addition, discretionary benefits may be available to assist OW/ODSP recipients with the cost of utility arrears, deposits and reconnection fees.	X																					X			Social Assistance recipients	X	X	X				"Energy assistance funds for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
Share the Warmth (STW)	Share the Warmth	Charitable	Share the Warmth is a registered not-for-profit charity that purchases heat and energy on behalf of families, seniors, terminally ill and disabled persons living at or below the poverty level.	X																	X		X	X		X	X					STW purchases heat and energy			"Energy assistance funds for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
The Winter Warmth Fund	United Way	Charitable	Eligible low-income households that have current or expected utility arrears ca receive assistance from the Winter Warmth Fund to pay their energy bills. The United Way administers the program through a network of community-based agencies across the province. Funds are credited directly to the electricity or gas account.	X																	X				X							Helps pay monthly bill			"Financial Assistance." Enbridge Gas Distribution. July 2008. <https://portal-plumprod.cgc.enbridge.com/portal/server.pt?space=CommunityPage&control=SetCommunity&cached=true&CommunityID=587&PageID=0>
The Heat and Warmth Program (THAW)	London Hydro	Emergency Assistance	THAW provides seasonal emergency financial relief to cover the cost of utility bill arrears in order to avoid disconnection of service.	X																											X			Arrearage amount	"Energy assistance funds for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
Fund for Utility Service Emergencies (FUSE)	Petersborough Utilities Services	Emergency Assistance	FUSE directly assists people in retaining electrical, water and sewage services and assists in avoiding evictions.	X																												Helps pay monthly bill			"Energy assistance funds for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
Heat Bank – Waterloo Region		Emergency Assistance	The Heat Bank can provide residents one-time-per-year emergency assistance with heating bills when they have exhausted assistance through Regional Social Services or when they have exhausted, or are not eligible for assistance, through Share the Warmth.	X																												Helps pay monthly bill			"Energy assistance funds for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
Keep the Heat - Windsor & Essex County		Rate Assistance	Keep the Heat provides energy assistance to eligible low-income households experiencing financial difficulties and/or in receipt of a notice of termination of utilities. The public and affected families are also educated about energy conservation and provided with tools such as window insulation kits.	X																					X							Helps pay monthly bill			"Energy assistance funds for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
Shelter Fund - Toronto		Rate Assistance	This fund is available to OW or ODSP recipients in Toronto who have one o more dependent children under the age of 18. This benefit, up to a maximum of $1500, may be received in addition to CSUMB to assist with last month's fue and electricity security deposits (i.e., establishing new account for services), rental, utility, or fuel arrears.	X																									X		X				"Energy assistance funds for low-income consumers." The Low Income Energy Network. 30 July 2008 <http://www.lowincomeenergy.ca/A55AB4/lien.nsf/All/help>
Hamilton Utilities Arrears Program	Hamilton Utilities	Rate Assistance	In addition to CSUMB and discretionary benefits that can be accessed by OW/ODSP recipients to pay for utility arrears, disconnection and security deposits, the City of Hamilton contributes $150,000 from its water/wastewater fund to help low-income singles or couples who are not in receipt of social assistance with these costs. Up to $1,500 in assistance per year for families with children; Up to $799 in assistance per year for singles and couples without children; Request will be made to stop shut-off notice immediately; Approved assistance will be paid directly to utility company; Security deposits will be refunded to the City of Hamilton for Ontario Works or Ontario Disability Support Program clients (if applicable)	X																		City of Hamilton's water/ wastewater fund			X			Low-income singles or couples not in receipt of social assistance	X	X	X				"Support Programs - Utilities Arrears." Public Health & Social Services: Support Programs in Hamilton. City of Hamilton. 13 August 2008 <http://www.myhamilton.ca/myhamilton/CityandGovernment/HealthandSocialServices/SocialServices/SupportPrograms/utilitiesArrears.htm>

				Provinces / Territories														Funding Sources					Customer Eligibility Requirements										How is Assistance		
Programs	Sponsor(s)	Program Type	Program Description	Ontario	Quebec	Nova Scotia	New Brunswick	Manitoba	British Columbia	Prince Edward Island	Saskatchewan	Alberta	Newfoundland and Labrador	Yukon	Northwest Territories	Nunavut	Funding Level	Ratepayers (Voluntary / Mandatory)	Provincial Tax / Surcharge	Federal / Provincial Grants	Charitable Contributions	Other	Families (National Child Benefit)	Seniors (Guranteed Income Supplement)	Income Level	Poverty Level	Disabled / Medical Condition / Need	Other	Security Deposit	Reconnection Fee	Arrearage	Other	Fixed Amount	Other	Source(s)
Éconologis - Agence de l'efficacité énergétique Community Program (for low-income households)	Hydro-Québec, Gazifère and Quebec's Energy Efficiency Fund	Energy Efficiency	This program provides free energy-saving advice and equipment to qualifying low-income householders who pay energy bills directly (but not to renters whose energy costs are included in their rent). Under the program, two-person teams of energy-efficiency technicians make home visits and provide personalized advice on reducing energy consumption and install energy-saving devices including draft proofing and sealing materials, tap aerators and low-flow showerheads. The free home visit and equipment is valued at $310, and a typical installation of thermostats is worth approximately $300. Studies suggest typical energy bill reductions of between 2.5 and 10% as a result of the program. To qualify, household income must be below specified thresholds.		X																				X							Free advice and equipment		Up to $610 per home	"Éconologis (Programme d'interventions auprès des ménages à budget modeste)." Agence de l'efficacité énergétique. 13 August 2008 <http://www.aee.gouv.qc.ca/habitation/menages/menages.jsp>
EnerGuide for Houses Assistance Program for Low- to Modest-Income Nova Scotians	Conserve Nova Scotia	Energy Efficiency	Low-to modest-income Nova Scotians that qualify for the EnerGuide for Houses Assistance Program will also receive a grant of up to $400 (provided they qualify for a provincial grant of at least $200) in addition to the provincial EnerGuide grant. Qualified participants will also be reimbursed the cost (including HST) of the initial home energy evaluation. If you're a homeowner with a net single income of less than $25,000 or a homeowner with a net family income of less than $40,000, you may qualify.			X																			X							Grants for energy improvements up to $400		Grants for energy improvements up to $400	"Nova Scotia EnerGuide for Houses Assistance Program for Low- to Modest-Income Nova Scotians." EnerGuide for Houses: Assistance Programs. Conserve Nova Scotia. 13 August 2008 <http://www.conservens.ca/consumerinfo/residential/energuideforhouses/assistanceprogram>
Residential Energy Affordability Program (REAP)	Conserve Nova Scotia and Dept of Community Services	Energy Efficiency	Program designed to help low-income households take control of their energy costs. Under the pilot program, Conserve Nova Scotia, funded energy efficient upgrades in 105 homes across the province. Under the current program, Conserve Nova Scotia has provided funding to upgrade an additional 200 homes. These homes are scheduled to be upgraded by fall 2008. Initial results indicate that participating homeowners save on average 30% on their energy bills. Participating homes first undergo a home energy evaluation, and then upgrades are completed to make the building more efficient (at no cost to the homeowner). There is no application for this program. All homes were selected based on pre-approved lists for housing programs from the Department of Community Services.			X																			X										"Residential Energy Affordability Program (REAP)." Residential: REAP (Low Income Programs). Conserve Nova Scotia. 13 August 2008 <http://www.conservens.ca/consumerinfo/residential/reap>
Energy Efficiency Retrofit Program for Low-Income Households	Department of Family and Community Services and Efficiency New Brunswick	Energy Efficiency	Low-income homeowners and landlords are eligible for grants to replace heating systems, seal air leaks, and upgrade ventilation systems, insulation, windows and doors. Assistance for homeowners is in the form of a non-repayable grant and a repayable loan. Owners of residential rental properties are eligible for a non-repayable grant only. The value of the grant depends on the type of building structure. Single, row, and semi-detached buildings are eligible for a grant of up to $4,500 per unit. Multiple unit buildings are eligible for grant of up to $1,500 per unit. Homeowners and landlords must have incomes below or at established income levels for the area in which they reside. Eligible participants must first have an energy advisor complete an energy evaluation of the property to identify appropriate energy improvements.				X																		X							Grants for energy improvements		Grants up to $4,500 for single family units and $1,500 for multiple unit buildings	"Energy Efficiency Retrofit Program for Low-Income Households." Residential - Funds Available for Energy Efficiency Home Programs. NB Energy Efficiency and Conservation Agency. 13 August 2008 <http://www.efficiencynb.ca/residential-e.asp>
Home Energy Assistance Program	Government of New Brunswick	Rate Assistance	The Home Energy Assistance Program is a one-time payment of $100, which will help low-income families to cope with high energy prices.				X																		X							One time payment of $100	X		"REVISED / Financial assistance for low-income families and paper mills." Communications New Brunswick. 6 July 2007 <http://www.gnb.ca/cnb/news/fin/2007e0880fn.htm>
Low-Income Seniors' Benefit Program	Government of New Brunswick	Rate Assistance	The Low-Income Seniors' Benefit Program is an annual rebate of $200 issued by the Government of New Brunswick to eligible low-income seniors.				X																	X	X							Annual rebate of $200	X		"REVISED / Financial assistance for low-income families and paper mills." Communications New Brunswick. 6 July 2007 <http://www.gnb.ca/cnb/news/fin/2007e0880fn.htm>
Regular Fuel Supplement	Department of Family and Community Services	Rate Assistance	The supplement is designed to assist social assistance clients with winter heating costs from November to April of each year. To qualify, social assistance clients should have a mortgage or a rental payment of over $100 per month.				X																					Social assistance clients with mortgage/rental payment of over $100/month				Supplemental assistance during winter months		Supplemental assistance during winter months	"REVISED / Financial assistance for low-income families and paper mills." Communications New Brunswick. 6 July 2007 <http://www.gnb.ca/cnb/news/fin/2007e0880fn.htm>
Emergency Fuel Supplement	Department of Family and Community Services	Rate Assistance	The supplement is provided to relieve some of the hardship caused by heating costs. The once-per-calendar-year benefit of up to $270 is provided to qualifying families. This supplement has been expanded to include social assistance recipients who are not eligible for the Regular Fuel Supplement, Income Supplement, or a heating allowance.				X																												"REVISED / Financial assistance for low-income families and paper mills." Communications New Brunswick. 6 July 2007 <http://www.gnb.ca/cnb/news/fin/2007e0880fn.htm>
Housing Heating Allowance	Department of Family and Community Services	Rate Assistance	The monthly allowance is provided to households receiving a rent subsidy, or individuals living in non-profit housing, and is determined by the size of the unit Residents use only 30% of their household income to pay rent. In situations where heating costs are not included in the rent, a heating allowance is provided.				X																												"REVISED / Financial assistance for low-income families and paper mills." Communications New Brunswick. 6 July 2007 <http://www.gnb.ca/cnb/news/fin/2007e0880fn.htm>
Neighbours Helping Neighbours	Manitoba Hydro and Salvation Army	Rate Assistance	This energy assistance program provides low income individuals, families and seniors who are unable to pay their energy bill due to personal hardship or crisis with: referrals to community support services, counseling and job training; and one-time emergency funding to assist with energy bills. Neighbours Helping Neighbours relies on private and corporate donations to fund its services. Manitoba Hydro matches all program donations dollar for dollar. You or someone you know may be eligible for assistance if: (a) you are not currently receiving social assistance; (b) you have a final or Shut off/Disconnection Notice; (c) you are experiencing problems that are beyond your control. For example: lower income individuals, families or seniors who are experiencing temporary hardship, crisis, or emergency situations (such as job loss, illness, medical expense, separation, death, funeral expenses or a major household repair bill); (d) you have not received assistance from this program in the last year; and (e) you are willing to meet with The Salvation Army to fill out an application form and provide proof of income for all househol					X										Voluntary			X		X	X	X										"Neighbours Helping Neighbours Expands Across Manitoba." Community: Programs. Manitoba Hydro. 13 August 2008 <http://www.hydro.mb.ca/community/neighbours_helping_neighbours/index.shtml>
Lower Income Energy Efficiency Program	Manitoba Hydro	Energy Efficiency	Qualified lower income households are eligible for energy efficient retrofits. Lower income households may qualify for: (1) An in-home energy evaluation and basic energy savings items: An energy advisor will identify opportunities to save energy in qualifying lower income households. In addition, these households will be provided with some basic energy efficient items, like compact fluorescent light bulbs, low flow showerheads and faucet aerators. These in-home energy efficiency services are provided at no cost to the lower income household; (2) Insulation upgrades: Based on the energy evaluation, insulation can be added to the attic, basement, crawlspace and wall cavity (up to Power Smart levels). Most or all of the costs will be covered by a combination of Manitoba Hydro and ecoENERGY Retrofit Program funding. (3) High efficiency heating system upgrade: A high efficiency natural gas furnace or boiler uses less energy, costs less to operate, helps conserve natural gas, and reduces greenhouse gas emissions. If you replace your standard natural gas furnace or boiler with a high efficiency natural gas furnace or boiler, Manito					X																	X										"Lower Income Energy Efficiency Program." Power Smart Savings, Rebates & Loans. Manitoba Hydro. 13 August 2008 <http://www.hydro.mb.ca/your_home/lower_income.shtml>
Utility Security Supplement	British Columbia	Rate Assistance	A supplement may be provided to assist recipients of income, hardship, and disability assistance with the cost of securing service for electricity or natural gas. This supplement is available under the Employment and Assistance Regulation and Employment and Assistance for Persons with Disabilities Regulation.						X																X		X		X						"Utility Security Deposit: Overview" Utility Security Supplement - Housing and Social Development. January 2007. Government of British Columbia. 13 August 2008 <http://www.gov.bc.ca/meia/online_resource/general_supplements/utility/>
Energy Saving Kits for Low Income Households	BC Hydro	Energy Efficiency	Free energy saving kit for low-income households contains: compact flourescent light bulbs; weather stripping; fridge and freezer thermometers; a low-flow showerhead.						X																X							Free energy saving kit			"Energy Saving Kits for Low-Income Households." BC Hydro - Power Smart for Home. July 2008. BC Hydro. 13 August 2008 <http://www.bchydro.com/powersmart/savingkits/savingkits56008.html>
Climate Action Credit	British Columbia	Energy Efficiency	On July 1, 2008, subject to approval by the legislature, British Columbia will begin to phase in a fully revenue-neutral carbon tax with built-in protection for lower income British Columbians. The purpose of the carbon tax is to encourage individuals and businesses to make more environmentally responsible choices, reducing their use of fossil fuels and related emissions. The tax has the advantage of providing an incentive without favouring one way to reduce emissions over another. Business and individuals can choose to avoid it by reducing usage, increasing efficiency, changing fuels, adopting new technology or any combination of these approaches. To help offset the cost of the carbon tax, lower-income British Columbians will receive an annual Climate Action Credit of $100 per adult and $30 per child; the credit will be paid quarterly along with the federal Goods and Services Tax Credit.						X																X										"Balanced Budget 2008: Backgrounder." Ministry of Finance. Province of British Columbia. 13 August 2008 <http://www.bcbudget.gov.bc.ca/2008/backgrounders/backgrounder_carbon_tax.htm>
ecoEnergy Audit Assistance for Low-Income Households	PEI Office of Energy Efficiency	Energy Efficiency	Provides financial assistance for an energy audit, performed through NRC's ecoEnergy Retrofit Program, to low-income homeowners with a household income less than $30,000, or receives the Guaranteed Income Supplement (Seniors) or receives the National Child Benefit. Pays the full cost of a pre and post retrofit audit to a maximum of $500 per household.							X													X	X	X							Retrofit audit up to $500 per household		Retrofit audit up to $500 per household	"ecoENERGY Audit Assistance for Low-Income Households." Office of Energy Efficiency. Government of Prince Edward Island. 13 August 2008 <http://www.gov.pe.ca/oee/index.php?number=1021703&lang=E>
Home Energy Low-Income Program (HELP) / Residential Energy Assistance Program	PEI Office of Energy Efficiency	Energy Efficiency	Low-income clients who have an ecoEnergy Energy Efficiency evaluation completed are eligible to have a HELP tradesperson complete comprehensive air-sealing that was identified in the audit report free of charge. Eligible individuals and families can receive a free home-energy-efficiency upgrade that includes up to $200 worth of energy-saving measures such as weather stripping and caulking windows, installing a programmable thermostat and a furnace tune-up. The program is open to both homeowners and those who rent a house or apartment and pay the heating costs. Those eligible for the program include: (a) individuals or families with a gross household income of less than $30,000; (b) families who qualify for the National Child Benefit; and (c) seniors who qualify for the Guaranteed Income Supplement.							X													X	X	X							Grants for energy efficiency improvements			"Efficiency Office Opens with Two Assistance Programs." Environment, Energy & Forestry News Release. Government of Prince Edward Island. January 2008. <http://www.gov.pe.ca/news/getrelease.php3?number=5528>
Share the Warmth Home Energy Efficiency Program	SaskEnergy, The Salvation Army and Saskatchewan Institute of Applied Science and Technology (SIAST)	Energy Efficiency	A community program offered to selected Saskatchewan families to help warm up their winter. Anyone can apply, but preference will be given to homeowners with an annual combined household income of no more than $45,000. Renters who pay all their utility bills may be considered.								X														X										"SaskEnergy's Share the Warmth Home Energy Efficiency Project." Climate Change Saskatchewan. 14 August 2008 <http://www.climatechangesask.ca/html/individuals/Your_Community/Share_The_Warmth_Home_Energy_Efficiency_Project__/index.cfm>

				Provinces / Territories														Funding Sources					Customer Eligibility Requirements										How is Assistance		
Programs	Sponsor(s)	Program Type	Program Description	Ontario	Quebec	Nova Scotia	New Brunswick	Manitoba	British Columbia	Prince Edward Island	Saskatchewan	Alberta	Newfoundland and Labrador	Yukon	Northwest Territories	Nunavut	Funding Level	Ratepayers (Voluntary / Mandatory)	Provincial Tax / Surcharge	Federal / Provincial Grants	Charitable Contributions	Other	Families (National Child Benefit)	Seniors (Guranteed Income Supplement)	Income Level	Poverty Level	Disabled / Medical Condition / Need	Other	Security Deposit	Reconnection Fee	Arrearage	Other	Fixed Amount	Other	Source(s)
Home Energy Improvement Program for Low-income Household	Government of Saskatchewan and Saskatchewan Housing Corporation	Rate Assistance	Financial assistance to defray the costs of home improvements such as heating system upgrades, insulation and draft proofing. The amount of the grant available varies by geographic region. Homeowners of single, semi-detached, and row housing are eligible for a grant of up to $4,000 in southern Saskatchewan and a grant of up to $4,700 in northern Saskatchewan. Rental property owners of single, semi-detached and row housing are eligible for a grant of up to $3,500 in southern Saskatchewan and a grant of up to $4,200 in northern Saskatchewan. Homeowners and rental property owners of multiple-unit buildings and rooming houses are eligible for a grant of up to $1,000 per unit in southern Saskatchewan and $1,200 per unit in northern Saskatchewan. To be eligible, households must have a gross annual income of less than $30,000 in southern Saskatchewan and less than $42,500 in northern Saskatchewan.								X																	X							Grants up to $4,700		Grants up to $4,700	"Saskatchewan Home Energy Improvement Program (SHEIP)." Social Services - Housing: Repairs and Renovations. Government of Saskatchewan. 13 August 2008 <http://www.socialservices.gov.sk.ca/home-repair>
Home Energy Improvement Program for Low-income Household - Rental	Government of Saskatchewan and Saskatchewan Housing Corporation	Rate Assistance	Provides financial assistance to landlords to assist with the cost of energy efficient upgrades to their properties; Maximum non-repayable grant of $3,500 per unit in southern Saskatchewan and $4,200 in northern Saskatchewan; To meet eligibility criteria, the owner of the property must: house tenants that have a gross annual household income below the Household Income Limits (HILs); maintain legal ownership of the property; maintain rent at or below the Median Market Rents; have a legitimate landlord / tenant relationship								X																	X							Grants up to $4,200		Grants up to $4,200	"Saskatchewan Home Energy Improvement Program (Rental-SHEIP)." Social Services - Housing: Repairs and Renovations. Government of Saskatchewan. 13 August 2008 <http://www.socialservices.gov.sk.ca/home-repair>
Emergency Assistance for Albertans Facing Utility Disconnection	Alberta Employment and Immigration	Rate Assistance	Alberta Employment and Immigration helps low-income Albertans who have received a disconnection notice from their gas or power company and have no other way of paying their overdue utility bills.									X														X						X				"Emergency Assistance for Albertans Facing Utility Disconnection." Alberta Employment and Immigration: Income Support. June 2007. Government of Alberta. 13 August 2008 <http://employment.alberta.ca/cps/rde/xchg/hre/hs.xsl/689.html>
Low Income Household High Efficiency Furnace CO2RE Rebate Program	City of Edmonton	Energy Efficiency	City of Edmonton low income residents who replace their furnace with an ENERGY STAR® qualified furnace (that has a 92.0% annual fuel utilization efficiency or better, with a DC variable-speed motor) through the federal Residential Rehabilitation Assistance Program (RRAP) may receive a high efficiency furnace rebate from CO2RE. Rebates of $2,000 per household are available.									X														X							Rebate up to $2,000		Rebate up to $2,000	"Frequently Asked Questions: $2,000 High Efficiency Furnace Rebate for Low Income Households." CO2RE Member Promotions. CO2RE. 13 August 2008 <http://www.co2re.ca/promotions.asp>
Provincial Home Repair Program (PHRP)	Newfoundland and Labrador Housing Corporation	Rate Assistance	Funding to: (a) assist low-income homeowners who require essential repairs to their homes; (b) bring dwellings up to minimum fire and life safety standards, with improvements in basic heating, electrical and plumbing services; and (c) provide seniors and the physically challenged who require accessibility changes to their residences the ability to carry out these renovations, which will allow them to remain in their homes for a longer period. NLHC provides funding to eligible homeowners in the form of grants and repayable loans. Funding is limited to the costs associated with essential repairs. Grant funding is available up to a maximum of $5,000 [$6,500 in coastal Labrador]. Essential repairs exceeding these levels may be addressed under a repayable loan of up to $10,000 [$13,000 in coastal Labrador].										X							X						X							Grants up to $6,500		Grants up to $6,500	"Provincial Home Repair Program (PHRP)." NLHC Housing Programs. Newfoundland and Labrador Housing Corporation. 13 August 2008 <http://www.nlhc.nf.ca/programs/phrp.htm>
Home Heating Rebate	Government of Newfoundland and Labrador	Rate Assistance	The Home Heating Rebate is available to residents of the province whose household income in 2006 is $40,000 or less and incur costs to heat their home regardless of the primary source of heat. Households with income up to $35,000 will be eligible to receive a maximum rebate amount of $300 if the primary source of heat is heating oil, stove oil or propane, $200 for other sources including electricity and wood, and $400 for Coastal Labrador communities regardless of the source of heat. Individuals and families with income between $35,000 and $40,000 will also receive assistance; however the rebate will be reduced on a sliding scale. The minimum rebate an eligible household will receive is $100.										X							X						X							Rebate up to $400		Rebate up to $400	"Home Heating Rebate." Finance - Tax Credits, Incentives and Benefits. Government of Newfoundland and Labrador - Canada. 13 August 2008 <http://www.fin.gov.nl.ca/fin/homeheating/>
Social Assistance	Yukon Health & Social Services	Rate Assistance	Yukon Social Assistance is a program that provides financial assistance to people who do not have enough money to live on. This program is to be used only as a last resort after all other possible sources of income have been explored. When you cannot meet your basic living expenses, and you have tried all other possible sources, then you may be eligible for Social Assistance. If you are eligible for income assistance from any other Government, Agency or Program you are required to access that source first before coming to the Yukon Government's income assistance program. A shelter allowance is provided to cover expenses. The amount varies depending on family size and what community you live in. The actual costs of utilities are also covered, up to a maximum depending on family size and time of year.											X												X										"Social Assistance." Programs & Services: Social Assistance. Yukon Health & Social Services. 13 August 2008 <http://www.hss.gov.yk.ca/programs/social_services/assistance/>
Pioneer Utility Grant	Yukon Health & Social Services	Rate Assistance	Pioneer Utility Grant is also available to seniors living in their own homes to offset the costs of utilities.											X										X											"Pioneer Utility Grant." Programs & Services: Services to Seniors. Yukon Health & Social Services. 13 August 2008 <http://www.hss.gov.yk.ca/programs/social_services/seniors/>
Senior Home Heating Subsidy	Government of the Northwest Territories	Rate Assistance	The Senior Home Heating Subsidy provides seniors with fuel, electricity or wood to heat their homes. For seniors who: are 60 years old or older; own and live in their own home; are not getting income assistance; have a low household income and meet an income test; are residents of the NWT; apply once every year between September 1 and March 31. The amount of benefits a senior can receive depends on the community in which a senior lives, the type of home heating required and the net household income level.												X									X	X										"Senior Home Heating Subsidy." GNWT Seniors - Housing. February 2007. Government of the Northwest Territories. 13 August 2008 <http://www.hlthss.gov.nt.ca/seniors/housing/senior_home_heating_subsidy.asp>
Contributing Assistance for Repairs and Enhancements (CARE): Low Income Housing Upgrades	Northwest Territories Housing Corporation and Government of the Northwest Territories	Energy Efficiency	This $2.5 million program will target 30%, or $750,000, annually to energy efficiency improvements in low-income households for the next two years. Program to assist existing homeowners in making necessary repairs to ensure a safe and healthy residence with an increased economic life. Assistance will provided in the form of a forgivable loan to subsidize the cost of preventative maintenance checks, repairs and renovations. The financial assistance is provided in increments based on the applicant's income, family size, and a measure of community need called the Core Need Income Threshold (CNIT). Additional assistance is available for improving the accessibility of dwellings for persons with disabilities.												X										X							Forgivable Loan			"Contributing Assistance for Repairs and Enhancements (CARE)." NWTHC Programs. Northwest Territories Housing Corporation. 14 August 2008 <http://nwthc.gov.nt.ca/pgm_CARE.html> "Energy for the Future: An Energy Plan for the Northwest Territories." Government of the Northwest Territories: Industry, Tourism and Investment and Environment and Natural Resources. March 2007. <http://www.iti.gov.nt.ca/energy/>

	FEDERAL								STATE / LOCAL					UTILITY		CHARITABLE
	LIHEAP FY2008 Funding	LIHEAP Income Eligibility Level	LIHEAP FY2007 Benefit	LIHEAP Households Served (FY2006/07 Estimate)	% of Eligible HHs ≤150% FPL Receiving Energy Assistance (2006)	Weatherization Assistance Program (WAP) Benefit (FY2006)	WAP Eligibility (FY2006)	WAP Households Served (FY2006)	Low Income Rate Assistance	Low Income Energy Efficiency	Low Income Emergency Assistance	Seasonal, Health, and Income Related Disconnection Policies	Low Income - Other	Low Income Rate Assistance	Low Income Energy Efficiency	Emergency Charitable Assistance Programs
Alabama	$ 17,111,350	150% Federal Poverty Level	Heating and Cooling: $70 min, $240 max	Heating: 110,340; Cooling: 40,000	4.3%	Max. benefit: $2,826	125% Federal Poverty Level	846		Neighbors Helping Neighbors Fund In 1996, Senate Bill 45 was passed in the legislature providing for a state low-income weatherization program to supplement federal funds by including a voluntary tax check-off option for state income-tax filers. Taxpayers may designate an amount of their refund as a voluntary contribution to the "Neighbors Helping Neighbors Fund". The Department of Economic and Community Affairs will administer the monies, which will help provide weatherization assistance to eligible recipients.		Alabama prohibits the disconnection of residential electric or natural gas service for nonpayment when the National Weather Service forecasts that the temperature at that location will be 32 degrees Fahrenheit or below for that calendar day.		Alabama Power Co: Customers who are verified as Supplemental Security Income (SSI) or Aid for Families with Dependent Children (AFDC) recipients will not be billed a monthly service charge of approximately $8.91. Alagasco: Customers who receive Supplemental Security Income (SSI) or Aid fo Families with Dependent Children (AFDC) will not be billed a monthly customer charge of about $8. Mobile Gas: Customers who receive Supplemental Security Income (SSI payments or Aid to Dependent Children) and who qualify, can have the customer charge of approximately $8 waived from their monthly gas bill.		Project Share: Project Share is funded by contributions from major electric and gas utilities' customers, employees, and stockholders. Alabama Power administers collections, and the Red Cross administers the rest of the program. The project operates year round and serves senior citizens, disabled persons, and those on fixed or low incomes. Cherokee Electric Cooperative - Operation Warm: Customer donations are used to assist the needy with their electrical bills. Funds are administered through the Cherokee County Crisis Center. Decatur Utilities - Operation Warm: Provides assistance to people who don't qualify for LIHEAP. Community Action bases its decision about who receives Operation Warm funds on income and necessary expenses, such as medications. The program runs from Dec. 1 through May 31, during which applicants are eligible for assistance only once. Joe Wheeler Electric - Operation Warm: Provides assistance to people who don't qualify for LIHEAP. Community Action bases its decision about who receives Operation Warm funds on income and necessary expenses, such as medications. The program runs from Dec. 1 through May 31, during which applicants are eligible for assistance only once. Hartselle Utilities - Operation Warm: Provides assistance to people who don't qualify for LIHEAP. Community Action bases its decisio
Alaska	$ 10,827,790	150% Federal Poverty Level	Heating: $170 min, $2,975 max	Heating: 8,887	12.8%	Avg. benefit: $6,000	60% State Median Income	697	Power Cost Equalization Program (PCE) PCE program provides economic assistance to customers in rural areas of Alaska where the kilowatt-hour charge for electricity can be three to five times higher than the charge in more urban areas of the state. The program seeks to equalize the power cost per kilowatt-hour statewide. For more detailed information, go to Alaska Statute 42.45.110.	Rural Residential Energy Rehab Program (Enhanced Weatherization) The state general fund provides weatherization assistance to low-income residents located between the Yukon-Kuskokwim Delta and the Northwest Arctic Borough in Alaska (nonroad-accessible communities), where winter temperatures can reach -40°F and fuel costs may consume as much as half of a family's monthly income. The program provides extensive energy-related repairs, heating and electrical improvements, and housing rehabilitation, in addition to energy conservation measures such as caulking and weather-stripping. Maximum assistance per household: $17,000; Households with income at or below 60% of the state median income are eligible; Households served (4/05-3/06): 90	General Relief Assistance (GRA) GRA provides for the basic needs of Alaskans not eligible for other state assistance programs. Examples of basic needs include shelter, and utilities. GRA can provide limited assistance for clothing, transportation, food, medical care and burial. Applicants must demonstrate and verify an unmet emergent need in the month of application.	Health: Alaska does not have a cold weather disconnect policy but does require utilities to delay for 15 days the disconnection of residential electric or natural gas service for nonpayment if the customer notifies the utility that a member of the household is seriously ill, over age 65, disabled, or dependent on a life-support system. Deferred Payments: The state requires utilities to offer deferred-payment arrangements to residential customers in danger of having their service disconnected for nonpayment. If the customer agrees and adheres to such an arrangement, the utility is prohibited from disconnecting service. Deferred-payment agreements must include the following requirements: The customer must pay one-third of the outstanding bill at the time of the agreement; The customer must pay off outstanding balance over a period not to exceed 12 months.			Golden Valley Electric Association (GVEA) - Home$ense An energy audit and energy saving measures are provided at no cost to Low-Income Weatherization Assistance Program recipients.	
Arizona	$ 8,275,252	150% Federal Poverty Level	Heating and Cooling: $25 min, $400 max	Heating and Cooling: 24,117	3.2%	Max. benefit: $2,672	150% Federal Poverty Level	627		Neighbors Helping Neighbors Energy Assistance Fund The Neighbors Helping Neighbors Energy Assistance Fund has helped to supplement LIHEAP and provide qualified low-income households with one-time crisis/emergency utility bill payments, energy conservation, and home weatherization. State tax forms include an option for taxpayers to make a voluntary contribution to the Neighbors Helping Neighbors fund. All funding for this program comes from taxpayers who decide to increase their tax payment or decrease their tax refund to make a contribution. The state treasury manages the fund and coordinates this assistance with the state LIHEAP and weatherization assistance programs. State residents with household income at or below 150% of poverty are eligible for assistance. The Neighbors Helping Neighbors fund is administered by the Department of Economic Security through local community offices.	Utility Repair, Replacement and Deposit (URRD) Established by the state legislature in 1989, the URRD program provides emergency assistance to eligible customers who need to make a utility deposit or have a heating or cooling appliance repaired or replaced. Assistance is limited to $2,000 per household, once a year.	Seasonal: Utilities are prohibited from disconnecting residential gas or electric service when the commission deems the current weather to be dangerous to health. This occurs when temperatures are at or below 32°F or at or above 95°F. Health: The state prohibits utilities from disconnecting residential service for nonpayment if a customer can establish (through a physician's documented professional opinion) that such an action would be especially dangerous to the health of the customer or other household resident, or if lifesupporting equipment in the home depends on utility service for operation. Customers in these cases may be required to enter into a deferred payment arrangement with the utility within 10 days after the termination date.		Arizona Public Service (2 programs) - [1] Energy Support Program Offers a discount up to 40% off the cost of electricity for customers who meet certain income guidelines. The income guidelines are based on 150% of the federal poverty guidelines and change every July 1st. The discount varies depending on how much electricity is used each month [2] Medical Care Equipment Program: Offers a discount up to 40% off the cost of electricity for customers who meet certain income guidelines. The income guidelines are based on 150% of the federal poverty guidelines and change every July 1st. The discount varies depending on how much electricity is used each month. Applicants must also provide a letter from a doctor showing a need of life sustaining medical equipment. Unisource Energy Services - C.A.R.E.S.: Customers whose income does not exceed 150% of the federal poverty level may be eligible for a deduction of up to $8 off their monthly electric bills and up to $15 off their natural gas bills, depending upon usage. CARES rates also apply to the Low-Income Medical Life Support Program for customers who are medically life-support dependent and w Salt River Project (2 programs) - [1] Economy Price Plan: Customers with limited	Arizona Public Service - Energy-Wise: Provides weatherization improvements or repairs to the home and energy education. Household income must be at or below 150% of the federal poverty level. Tucson Electric Power: Since 1982 the Tucson Urban League and Pima County have been assisting low-income residents in reducing energy use and lowering their utility bills by implementing year-round weatherization measures - at no cost to eligible customers. TEP conducts energy audits and provides funding for weatherization measures. Southwest Gas - Low-Income Energy Conservation Program Energy-saving measures are available to income-qualified customers, at no cost. Examples of energy-saving measures are caulking, insulation, weather-stripping, ductwork repairs and windows.	Arizona Public Service - Project S.H.A.R.E. (Service to Help Arizonans with Relief on Energy) Project S.H.A.R.E may be able to help pay energy (gas, electric, oil, wood) bills for seniors over 60, living on a fixed income and facing a financial emergency or for customers under age 60 and experiencing special hardships or for disabled with no source of income. Southwest Gas Corporation - Energy Share Energy Share is an emergency fund that provides direct assistance to qualified people with unexpected financial difficulties, such as the loss of a job or a medical emergency. All Energy Share donations are managed and distributed by The Salvation Army. Tucson Electric Power Company (2 programs) - [1] Help with Emergency Energy Relief Operation H.E.E.R.O. provides one-time payments on energy bills for low-income customers. Customer donations fund the program, which is administered by the Salvation Army. [2] Low-Income Fund for Emergencies (LIFE) Fund In 1996, Tucson Electric Power Company set aside $4.5 million in shareholder funds for the LIFE Fund. The interest generated from the fund – about $250,000 per year – has been used to offset cuts Sulphur Springs Valley Electric Cooperative, Inc. - Operation Roundup Customer donations help families cope with emergencies, illne Trico Electric Cooperative - Operation Roundup Customer donations help Trico members in emergency situations and worthy organi
Arkansas	$ 13,056,769	125% Federal Poverty Level	Heating: $42 min, $111 avg, $259 max	Heating: 56,426; Cooling: 49,423	7.8%	Max. benefit: $2,744	125% Federal Poverty Level	579				Seasonal: Arkansas prohibits the disconnection of residential electric or natural gas service for nonpayment when the National Weather Service forecasts that the temperature at that location will be 32°F or below, or 95°F or above (in the case of disabled or older residents) for that calendar day. Health: The state requires utilities to delay for up to 30 days the disconnection of residential service for nonpayment if a customer or other permanent household resident presents a physician's certificate stating that suspension of utility service would cause a significant decline in the householder's health. Deferred Payments: Electric and natural gas utilities are required to offer a deferred-payment arrangement to residential customers in danger of disconnection for nonpayment and are prohibited from disconnecting service if a customer agrees and adheres to such an arrangement.		Entergy Arkansas: Sales tax exemption on the first 500 kWh used each month for customers with an annual household income of less than $12,000. Empire District Electric Company - Empire's Action to Support the Elderly (EASE): Provides late fee and security deposit waivers for seniors age 60 and older and disabled customers.		American Electric Power - Neighbor to Neighbor Customer and AEP donations are distributed through United Way. Arkansas Western Gas - Hearts Warming Homes: Provides heating assistance to customers in Northwest, North Central and Northeast Arkansas. The program will operate from November to April and assistance grants re based on need and not strict income guidelines. The fund is administered by The Salvation Army. CenterPoint Energy - Good Neighbor Fuel Fund Donations from Arkla Gas customers and employees are matched by Arkla. The Good Neighbor Fuel Fund is integrated and coordinated with LIHEAP by supplementing LIHEAP dollars after the program has ended when benefits are insufficient to meet the household's needs. Empire District Electric Company - Project Help Project Help extends a helping hand to needy senior citizens 55 years or older and handicapped persons. The program is administered by the Red Cross which screens applicants and provides relief where the need is greatest. Entergy - Beat The Heat During May, thousands of fans were distributed to customers living in the Entergy service area. Entergy - Project Deserve: Project Deserve is funded by customer, employee and stockholder donations and provides crisis assistan
California	$ 91,797,411	60% State Median Income	Heating: $131 min, $479 max	Heating: 123,463	6.2%	Max. benefit: $1,506	60% State Median Income	20,617		Weatherization and Energy-Efficient Rehabilitation (WEER) The California Conservation Corps, in partnership with the state's Department of Community Services and Development, provides no-cost home repair and weatherization services to low-income households through the WEER program. WEER also provides on-the-job training to low-income youths who participate in basic weatherization activities. WEER crews perform minor home repairs to bring houses up to minimum standards, and then perform standard weatherization services. Maximum benefit per household: $2,500. WEER is funded through California's petroleum violation escrow account. State residents with household incomes at or below 150% of poverty are eligible for assistance. In addition, WEER targets houses that are in disrepair and do not meet the minimum building conditions for weatherization.		Health/Deferred Payments: There is no weather-related disconnect policy in California, but the state prohibits utilities from disconnecting residential natural gas or electric service for nonpayment if the following requirements are met: A licensed physician certifies that disconnection would be life-threatening to the customer, and the customer agrees to a deferred-payment agreement; The customer is granted an extension or agrees to a deferred-payment arrangement (not to exceed 12 months) to pay the delinquent balance.		REFER TO DETAILED STATE SUMMARY Through the California Alternate Rates for Energy (CARE) program eligible customers receive a 20% discount on electric and natural gas bills. Eligibility: total household income is at or below 200% of federal poverty level. The CARE income guidelines, effective June 1, 2007, are as follows: Household size 1 or 2 = Income $29,300; Household size 3 = Income $34,400; Household size 4 = Income $41,500; Household size 5 = Income $48,600; Add $7,100 for each additional household member	REFER TO DETAILED STATE SUMMARY Low-Income Energy Efficiency (LIEE) Services include attic insulation, energy efficient refrigerators, energy efficient furnaces, weatherstripping, caulking, low-flow showerheads, water heater blankets, and door and building envelope repairs which reduce air infiltration. Eligibility: 200% of federal poverty level.	REFER TO DETAILED STATE SUMMARY
Colorado	$ 31,729,192	185% Federal Poverty Level	Heating: $201 min, $370 avg, $700 max	Heating: 93,473	11.4%	Avg. benefit: $2,800	185% Federal Poverty Level	4,082	Property Tax, Rent, and Heat Rebate Operated through the state Department of Revenue, allows tax rebates for home heating payments to residents at least 65 years old, surviving spouses at least 58 years old, or to disabled. The income limit for single households is $11,000; for married couples, $14,700. Qualified applicants can receive a rebate of up to $600 of their property tax and $192 directly or as part of their rent payments, by filing the Property Tax/ Rent/Heat Rebate Application Form 104PTC. [39-31-101 C.R.S.]			Health: Colorado does not have a temperature-based disconnect policy for residential natural gas or electric service. Instead, utilities are required to delay for up to 60 days disconnection of residential service to households where a medical professional certifies that such an action would result in a decline in the health of the customer or other permanent household resident. Deferred Payments: Colorado prohibits the disconnection of residential natural gas or electric service if the customer pays at least 1/10 of arrears and agrees to a deferred-payment arrangement not to exceed six months.			Energy $avings Partnership Program Provides no cost energy efficiency services to income-eligible customers, seniors and disabled. Services can include an energy audit, attic, wall and crawlspace insulation, air leakage reduction, appliance safety inspections, forced air efficiency assessment, high efficiency lighting surveys and other safety inspections. Energy Resource Center - ERC: The Energy Resource Center offers free home weatherization, insulation and furnace services to low-income families. Customers currently receiving LEAP, Temporary Assistance for Needy Families, Supplemental Security Income or MEDICAID assistance automatically qualify for ERC services. Colorado Springs Utilities - Home Efficiency Assistance Program (HEAP) A partnership with the Energy Resource Center, HEAP provides energy and water efficiency measures and conservation education for customers with household incomes at or below 225% of federal poverty guidelines. Measures include insulation, air sealing, energy efficient light bulbs, low flow faucets and toilets, and furnace repair or replacement. Fort Collins Utilities - REACH (Residential Energy Assistance Through Commun	Energy Outreach Colorado - Utility Assistance Program Distributes energy assistance dollars year round through 78 community-based organizations at 93 sites reaching all 64 Colorado counties. The funds provide emergency fuel bill assistance for Colorado's lo income households facing an energy crisis. Aquila - Aquila Cares Employee contributions are matched dollar for dollar, up to $10,000. $15,000 is earmarked to support local weatherization efforts including weatherstripping, caulking and other energy-saving actions. Customer donations are matched at 50 cents on the dollar, up to a combined total of $115,000. Donations are managed locally throughout the seven-state Aquila service area. Local assistance agencies determine eligibility and distribute funds. Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. City of Fountain - Lighten the Load Bill payment limited to $150 once per year for water, electricity or wastewater. Must have disconn City of Longmont - COPE Utility bill payment assistance. Must apply for LEAP first and have a disconnect notice. City of Loveland Water and Power Department - Help a Neighbor in Distress (HAND) The HAND project helps qualified applicants av Colorado Springs Utility Company - Citizens Option to Provide Energy (COPE) Project COPE is funded by donations from citizen-own Delta Montrose Electric Association - Operation Roundup Customer donations help individuals and organizations in the community. Fort Collins Utilites - Payment Assistance Fund Customers with a shut off notice are eligible for help through the Payment Assistance Mountain Parks Electric, Inc. - Operation Roundup Customer donations fund a charitable trust. Funds are then distributed to needy in Mountain View Electric Association, Inc. - Round-Up Customer donations are distributed to needy individuals and families and to non Yampa Valley Electric - Caring Consumers Caring Consumers is funded by customers that round up electric bills to the next highest
Connecticut	$ 41,754,126	150% Federal Poverty Level; 200% Federal Poverty Level (seniors and disabled)	Heating: $400 min, $537 avg, $675 max	Heating: 86,000	10.7%	Avg. benefit: $2,826	200% Federal Poverty Level	809	Contingency Heating Assistance Program (CHAP) CHAP is for households with higher incomes, 60% of State Median Income, than would qualify for the Connecticut Energy Assistance Program. State Appropriated Fuel Assistance Program (SAFA) The State General Assembly provides an annual appropriation of state funds for energy assistance benefits to elderly and/or disabled households with incomes between 151-200% of poverty guidelines. These and additional state funds provided by the General Assembly supplement the Connecticut Energy Assistance Program (LIHEAP).			Seasonal: Between November 1 and April 15, Connecticut prohibits utilities from disconnecting natural gas or electric service to residential customers who qualify for "hardship" status by meeting any of the following criteria: Receive state or federal assistance or have incomes at or below 125% of the federal poverty guideline; Are unemployed with a household income at or below 300% of the federal poverty guideline; Are seriously ill or disabled; Will potentially be deprived of food or other life necessities if required to pay the delinquent bill. Health: Connecticut requires natural gas and electric utilities to delay for up to 15 days disconnection of service to residential customers where it has been certified by a physician that such an action would result in a decline in the health of the customer or a permanent household resident. Medical certificates may be renewed every 15 days for as long as the medical condition persists. Deferred Payments: Before disconnecting service for nonpayment, natural gas and electric utilities must offer residential customers an opportunity to enter into a deferred-payment arrangement. If the customer agrees and adheres to such an		A systems benefits charge (SBC) imposed on customers of the state's two investor-owned utilities – Connecticut Light & Power and United Illuminating – pays for some low-income programs. SBC-funded arrearage, uncollectibles, and hardship programs for both utilities amounted to about $7.2 million in 2004. All gas public service companies are required by statute to operate an arrearage forgiveness program for gas heating customers. Arrearages are forgiven if customer makes regular payments. Eligibility criteria include: arrears of $100 or more that are 60+ days overdue, income of less than 200% FPG, and have had at least $25 paid toward bill by LIHEAP (or other assistance program). Electric utilities have voluntary arrearage forgiveness as part of budget programs. Connecticut Light and Power (3 programs) - [1] NUSTART Customers can reduce or eliminate their past-due balance if they pay an agreed-upon budgeted amount on time, each month. Eligibility: arrears of $100 or more that are 60+ days overdue, income of less than 200% FPG, and have had at least $25 paid toward bill by LIHEAP (or other assistance program) [2] Matching Payment Plan Connecticut Natural Gas - Matching Payment Plan Customers who qualify for ma Southern Connecticut Company - Matching Payment Pla: Customers who qualify	The mandated system benefits charge (SBC) for energy efficiency is assessed on all electricity sold by the state's two investor-owned electric utilities. The fund is used for programs affecting all customer classes. Of this amount, Connecticut Light and Power Company and United Illuminating Company are spent about $1 million in 2004 on low-income energy efficiency, mostly though community action agencies. Connecticut Light and Power - Low-Income Weatherization Residential Assistance Program (WRAP): Free for eligible customers who use more than 2,000 kilowatt-hours of electricity a year. Households with an income of up to 200% of the federal poverty level qualify. Connecticut Natural Gas (2 programs) - [1] Energy Audit On site energy audits are performed to provide recommendations of energy conservation measures. Each audit includes a review of the dwellings energy consumption pattern, air infiltration characteristics, the number of inhabitants and other variables affecting energy consumption. There is no charge for qualified/identified hardship customers. [2] Insulation and Weatherization Professional weatherization and in United Illuminating Co. - UI HELPS For customers on a limited income, UI Helps	Operation Fuel: Operation Fuel is a private, non-profit program that provides emergency help with energy or utility bills for people who are not eligible for CEAP or SAFA. Connecticut's legislature passed a law requiring all of the state's gas and electric utilities with at least 75,000 customers to facilitate the collection of donations for Operation Fuel. In most instances, eligible families have incomes at 151 to 200% of the federal poverty level. Warm Up Fund: Community donations provide funds for fuel assistance in Westport and Weston. The Windsor Fuel Bank Additional fuel assistance is available through The Windsor Fuel Bank for CL&P and Connecticut Natural Ga customers. Donations are made to the Windsor Community Service Council and can be used to help people who do not qualify for other assistance programs.
Delaware	$ 5,542,056	200% Federal Poverty Level	Heating: $200 min, $535 max; Cooling: $200 max	Heating: 15,137; Cooling: 1,921	6.6%	Avg. benefit: $2,500	150% Federal Poverty Level	475				Seasonal: Delaware prohibits disconnection of residential electric or natural gas service from November 15 through April 15 for nonpayment if the National Weather Service forecasts the temperature to be 20°F or below on the day the customer's service is slated to be disconnected. Health: The state prohibits disconnection of service to residential customers when a medical professional certifies that such an action would result in a decline in the health of the customer or a permanent household resident.				Chesapeake Utilities - Sharing Program The Sharing Program assists elderly, disabled or fixed income households with winter heating costs. Customer donations and matching shareholder contributions are administered by Catholic Charities in Kent and New Castle counties and by the Salvation Army in Sussex county. Delmarva Power (Conectiv) - Good Neighbor Fuel Fund Conectiv matches customer contributions with a donation from shareholders. A household must first apply for LIHEAP. Funds are administered by the Salvation Army.
District of Col	$ 6,484,484	60% State Median Income	Heating and Cooling: $31 min, $1349 max	Heating: 29,500	8.2%	Max. benefit: $2,672	60% State Median Income	1,084				Seasonal: The District of Columbia Public Service Commission prohibits disconnection of residential electric or natural gas service for nonpayment when the National Weather Service forecasts that the temperature at that location will be 32°F or below for that calendar day. Health: The Commission requires that utilities delay for up to 21 days disconnection of residential service if the customer provides a physician's certificate or notice from a public health official stating that disconnection would be detrimental to the health and safety of the customer or permanent household resident. The customer is also required to enter into a deferred-payment plan. Disconnection may be delayed for an additional 21 days by renewal of the certificate or notice.		The Public Service Commission requires Potomac Electric Power Company (PEPCO), and Washington Gas to offer discount rates to low-income residential customers. PEPCO - Residential Aid Discount on first 400 kWhs of electricity used each month. This translates into a savings of up to $5 per month or $60 a year. Washington Gas Company - Residential Essential Service (RES) This program offers discount gas rates, based on household size and income level, during the winter months from November through April. There are three classifications: Class C may receive a total discount up to $142.02, Class B up to $151.03 and Class A up to $189.08.		Washington Gas Company - Washington Area Fuel Fund (WAFF) WAFF, operated by the Salvation Army, aids customers who need assistance paying their home heating bills. Funds are available January 1 through May 31. To apply for help, contact your local Salvation Army.
Florida	$ 27,075,265	150% Federal Poverty Level	Heating and Cooling: $100 min, $200 max	Heating: 33,816; Cooling: 56,513	1.7%	Max. benefit: $5,652	150% Federal Poverty Level	1,400	City Electric System, Key West of Florida - Senior Citizen's/Disabled American Veteran's Discount: To be eligible, applicants must be 62 years or older or totally or permanently disabled American Veteran. Annual income must not exceed $17,196 per household. Applications are accepted through March 31; must reapply each year.	In 1992 the Florida legislature passed the William E. Sadowski Affordable Housing Act. Funding comes from a portion of documentary stamp taxes on deeds and supports two programs that supplement the state's WAP State Housing Initiatives Partnership which funds weatherization measures; and the Low-Income Emergency Home Repair Program, which funds emergency and energy-related home repairs. Tampa Electric - Weather Care: Free home improvements available to senior citizens 60 years and older on low, fixed incomes whose homes are in need of energy-related improvements. This program is a joint service offered by Tampa Electric and The Centre for Women.		Florida does not have state-mandated disconnection policies in these areas.				Florida Power & Light Company - Care to Share Program Provides energy assistance to customers who are in a crisis situation and are unable to pay their electric bill. A household may receive assistance of up to $500 for electric service once in a 12-month period. Progress Energy - Energy Neighbor Fund Low-income families facing unexpected energy costs can receive help through the fund. All funds are distributed through local social service agencies to pay for electricity, gas, oil or wood. Tampa Electric - SHARE: Helps elderly customers who are low-income and/or medically disabled pay their energy-related bills. JEA - Neighbor To Neighbor: Emergency energy-related assistance for elderly, disabled and low-income citizens. City of Lake Worth Utilities - Share to Care: Customer donations are used to assist needy families with their bills. The fund is administered by the Salvation Army. City of Leesburg - Citizens Utility Relief Effort (C.U.R.E.) Provides assistance to utility customers who are unable to pay their bill. The fund may be used in the event of loss of employment or an unexpected illness or injury. Guidelines set the criteria for extending assis City of Tallahassee Utilities - Project Share One-time financial assistance payments for eligible customers. Project Share funds are a Clay Electric Cooperative - Project Share: The Salvation Army handles the distribution of the fund and determines eligibility. Contact Florida Keys Electric Cooperative - Operation Roundup Funds will be given to local individuals, families or organizations with special Fort Pierce Authority - Project Care: Project Care assists utility customers in need of emergency utility assistance. Contributions are
Georgia	$ 21,407,149	150% Federal Poverty Level	Heating: $220 min, $238 avg, $250 max; Cooling: $250 max	Heating: 102,100; Cooling: 40,000	3.6%	Max. benefit: $2,684	150% Federal Poverty Level	2,517				Seasonal: Between November 15 and March 15, Georgia prohibits disconnection of residential electric or natural gas service whenever the National Weather Service forecasts that the temperature at that location will be 32°F or below during a 72-hour period beginning at 8 a.m. on the date of the proposed disconnection. During the winter protection period, utilities are prohibited from disconnecting residential service if a customer agrees in writing to a deferred payment plan and adheres to the arrangement. Health: Georgia requires natural gas and electric utilities to delay for 30 days—or the duration of the illness, whichever is less—the disconnection of residential service when a medical professional certifies that such an action would result in a decline in the health of the customer or other permanent household resident.	The regulated natural gas provider program provided by SCANA Energy and partially funded by the state's universal service fund, provides natural gas service to low income households and to consumers who are unable to obtain or maintain natural gas service from another marketer. Households meeting the low income requirements established by the Georgia Department of Human Resources qualify for a reduced security deposit, special rates and a lower customer service fee. To sign up, customers need to contact the community action agency serving their county. Those not meeting low-income requirements may still qualify for service with the Regulated Provider.	Since 1989, the Public Utility Commission (PUC) has mandated that major gas and electric utilities waive their monthly service charge for customers over age 65, who own their homes, and earn less than $12,000 per year. Atlanta Gas Light Senior citizens who are 65 years of age or older and have a total annual combined household income of $12,000 or less are eligible for a $10.50 monthly discount on their base charge. To apply contact your gas marketer. Georgia Natural Gas: Customers who are 65 years of age or older with an annual combined gross income per household of $12,000 or less are eligible for a $14.00 monthly discount on their base charge. Georgia Power: The monthly base charge ($10.50 for gas and $14.00 for electric) is waived for customers who are at least 65 years old and the total household income is not more than $12,000 annually. SCANA Energy: Customers who are 65 years of age or older with an annual combined gross income per household of $12,000 or less are eligible for a $14.00 monthly discount on their AGL base charge. Carroll Electric Membership Corporation - Senior Citizen Discount Members ove		The Heating Energy Assistance Team (HEAT) The HEAT program is administered by the Georgia Department of Human Resources statewide through Community Action Agencies. Private citizens and the natural gas industry provide funding. Project SHARE: A statewide program funded by electric utility customers who donate through their monthly electric bills. The program is administered by The Salvation Army. Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. Canoochee Electric Membership Corporation - Operation Round Up Members donate funds to provide assistance for worthy individuals and organizations in the community. Coweta-Fayette Electric Membership Corporation - Operation Round-Up® Members contribute to a fund which is awarded to various individuals and organizations in need. Habersham Electric Membership Corporation - Operation Roundup Financial assistance for worthy individuals and activities. Funded Snapping Shoals EMC - Operation Roundup Provides assistance for families and individuals who are facing serious short-term or lon Walton EMC - Operation Roundup Customer donations provide assistance for families and groups. The special fund is administered
Hawaii	$ 2,137,116	150% Federal Poverty Level	Heating: $371 avg	Heating: 5,444	3.6%	Max. benefit: $2,000	150% Federal Poverty Level	107				Health: Hawaii does not have a weather-related disconnection policy, but the state prohibits utility companies from disconnecting electric service to residential customers who need the service to power life-support equipment.	The County of Kauai offers low interest Residential Rehabilitation Loans for qualifying homeowners.		Hawaiian Electric Company Starting in June, 2008, qualified customers on Oahu can sign up to receive energy efficient equipment at no cost through Hawaiian Electric Co.'s residential low-income program. Covered under the program are compact fluorescent lights, faucet aerators, low-flow showerheads and water heater temperature set backs. Applications will be accepted through December 31, 2008 or until the program is full. t aerators, low-flow showerheads and water heater temperature set backs.	
Idaho	$ 12,376,499	150% Federal Poverty Level	Heating: $105 min, $472 max	Heating: 32,844	14.9%	Max. benefit: $2,826	150% Federal Poverty Level	1,395				Seasonal: Idaho prohibits regulated utilities from disconnecting natural gas or electric service to residential customers between December 1 and February 28 if the household includes children under age 18, persons who are infirm, or persons age 62 or older. Health: Idaho requires natural gas and electric utilities to delay for up to 30 days disconnection of residential service for nonpayment when a medical professional certifies that such an action would result in a decline in the health of the customer or other permanent household resident. Deferred Payments: Idaho prohibits utilities from disconnecting service to customers who agree to a deferred payment arrangement. Customers may be offered participation in the Winter Payment Plan but no customer is required to participate. Utilities cannot disconnect services of Plan participants between November 1 and March 31. Monthly payments under the Winter Payment Plan are half the amount required under the state's Level Payment Plan.		Avista Utilities - LIRAP: A low-income rate assistance program funded by Avista customers.	Avista Utilities: Avista Utilities customers with qualifying incomes can receive weatherization (insulation and air sealing) or heating system improvements through Avista Utilities and their local community action agency. Idaho Power: Idaho Power provides financial assistance to Idaho and Oregon Community Action Partnership (CAP) agencies to help cover the cost for weatherization of electrically heated homes of qualified customers.	Avista Utilities - Project Share: Project Share is a community program supported by shareholders, customers and employees. The funds are forwarded to community action agencies, which work with each family. Grants are available to those in need without regard to their heating source. Contact your local community action agency. Clearwater Power Company - Helping Hand Program The Co-op created the Helping Hand Program to assist low and fixed income households and those with unexpected emergencies. Customer contribution are disbursed through Community Action Agencies. Idaho Power Company - Project Share Administered through the Salvation Army, Project Share is available year round to help those who cannot pay winter heating bills due to illness, disability, age, or unemployment. Intermountain Gas Co. (2 programs) - [1] Project Warmth Customer contributions are distributed by community agencies [2] Project Share: Assistance with temporary heating emergencies. Kootenai Electric Cooperative - Operation Roundup Customer donations are placed in trust and administered by an independent Boa Utah Power - Lend a Hand Utah Power matches customer donations dollar-for-dollar and works with local non-profit agencies that he

FEDERAL

	LIHEAP FY2008 Funding	LIHEAP Income Eligibility Level	LIHEAP FY2007 Benefit	LIHEAP Households Served (FY2006/07 Estimate)	% of Eligible HHs ≤150% FPL Receiving Energy Assistance (2006)	Weatherization Assistance Program (WAP) Benefit (FY2006)	WAP Eligibility (FY2006)	WAP Households Served (FY2006)
Illinois	$ 114,565,493	150% Federal Poverty Level	Heating: $100 min, $400 avg, $1045 max	Heating: 360,000; Cooling: 55,000	8.3%	Max. benefit: $4,400	150% Federal Poverty Level	7,100
Indiana	$ 51,872,037	150% Federal Poverty Level	Heating: $100 min, $250 avg, $350 max	Heating: 143,000	11.2%	Max. benefit: $2,826	125% Federal Poverty Level	2,020
Iowa	$ 36,762,408	150% Federal Poverty Level	Heating: $320 avg	Heating: 89,638	17.8%	Avg. benefit: $4,700	150% Federal Poverty Level	2,064
Kansas	$ 17,030,712	130% Federal Poverty Level	Heating and Cooling: $294 avg	41,003	1.7%	Avg. benefit: $2,826	150% Federal Poverty Level; or 60% State Median Income	1,279
Kentucky	$ 27,230,294	130% Federal Poverty Level	Heating: $250 max	Heating: 100,485	15.1%	Max. benefit: $3,826	150% Federal Poverty Level	1,162
Louisiana	$ 17,493,729	60% State Median Income	Heating and Cooling: $150 min, $550 max	Heating: 31,800; Cooling: 46,474	3.2%	Max. benefit: $2,741	150% Federal Poverty Level	526
Maine	$ 26,815,321	150% Federal Poverty Level; 170% Federal Poverty Level (elderly >60, children <2, or persons susceptible to hypothermia with medical documentation)	Heating: $5 min, $588 avg, $800 max	Heating: 48,000	20.4%	Avg. benefit: $2,744	170% Federal Poverty Level	700
Maryland	$ 31,870,606	175% Federal Poverty Level	Heating: $48 min, $410 avg, $1100 max	Heating: 89,108	8.5%	Avg. benefit: $2,826	150% Federal Poverty Level	1,291
Massachusetts	$ 82,797,407	200% Federal Poverty Level	Heating: $235 min, $490 avg, $687 max	Heating: 138,693	10.9%	Max. benefit: $4,600	200% Federal Poverty Level	2,900
Michigan	$ 108,769,894	Heating: 110% Federal Poverty Guidelines; Crisis: 60% State Median Income	Heating: $201 avg	Heating: 358,801	8.1%	Max. benefit: $2,500	150% Federal Poverty Level	3,107

STATE / LOCAL

	Low Income Rate Assistance	Low Income Energy Efficiency	Low Income Emergency Assistance
Illinois	Effective 1998, the Supplemental Low-Income Energy Assistance Fund (SLEAF) was authorized through electric utility restructuring legislation. The law directed gas and electric utilities to assess a monthly surcharge from customers and deposit it into a state fund, which the General Assembly appropriates yearly to the state Department of Commerce and Community Affairs, the LIHEAP and weatherization grantee. Annually, about 80% of the fund, $65 million, goes for lo income bill payment assistance, and 10%, about $7.6 million, supplements the state's weatherization program. LIHEAP makes payments from the fund directly to utilities. SLEAF funds may be used only for assistance to low-income customers of the utilities that assess the surcharge.	Effective 1998, the Supplemental Low-Income Energy Assistance Fund (SLEAF) was authorized through electric utility restructuring legislation. The law directed gas and electric utilities to assess a monthly surcharge from customers and deposit it into a state fund, which the General Assembly appropriates yearly to the state Department of Commerce and Community Affairs, the LIHEAP and weatherization grantee. Annually, about 80% of the fund, $65 million, goes for lo income bill payment assistance, and 10%, about $7.6 million, supplements the state's weatherization program. LIHEAP makes payments from the fund directly to utilities. SLEAF funds may be used only for assistance to low-income customers of the utilities that assess the surcharge.	City Of Chicago - Emergency Housing Assistance Program Emergency repair grants are available to qualified low-income homeowners. This may include repair or replacement of heating units, emergency roof repairs and other energy saving conservation activities. Good Samaritan Energy Trust Fund Created by the Good Samaritan Energy Plan Act in 2003, allows Illinois residents to contribute money towards emergency heating bills of low-income households. County agencies grant funds to low-income consumers to pay overdue gas or electric bills in order to have household gas or electric utility service reconnected. The Good Samaritan reconnection agreement allows LIHEAP recipients to get their heat restored if they agree to pay $250 or 20 percent of the money they owe and enter into a payment plan for the balance. Grants go directly to eligible low-income residents of the county from which funds were donated.
Indiana			
Iowa			
Kansas			
Kentucky	The Department of Social Services Preventive Assistance Program initiative assists families with an energy payment of up to $300 per family if payment wou prevent removal of a child from the family or assist in reuniting the child with the family. Families must have exhausted or been denied all other means of public assistance.	Project WARM: Since 1982, Project WARM has provided free weatherization and energy conservation services to residents of Louisville and Jefferson County. Weatherization measures include sealing air leaks, adding attic insulation, and offering energy education. Free self-help classes on window cover installation and conservation measures are available during the winter. Summer Cooling: Each summer, air conditioners are loaned to people whose health is threatened by the high heat and humidity as verified by their doctors. The program was established and operates through local donations. Available in Fayette, Bourbon, Harrison, and Nicholas Counties. Air conditioners and fans are available in Louisville to households with incomes at 110% of federal poverty income guidelines or below. Households that include a member with a life-threatening medical condition are given an air conditioner and a volunteer technician to install it. Those who meet the poverty guidelines, but not the medical criteria, are given a fan. Louisville Metro Housing (Weatherization): Installs weatherization materials for lo	
Louisiana			
Maine		Central Heating Improvement Program (CHIP): Grants to low-income homeowners and renters to reduce energy costs by improving home energy efficiency; eligibility: income is within 150% of federal poverty guidelines. If your household includes seniors (age 60 and above) or small children (age two and under), you may be eligible if your income is within 170% of federal poverty guidelines. When you apply for the Low Income Heating Energy Assistance Program (LIHEAP), you are automatically considered for the CHIP Programs. Maximum CHIP grant: $2,500 (lifetime)	The General Assistance Program is provided in each town to help people in emergencies, including energy emergencies Emergency Moratorium: The Public Service Commission may declare a partial or complete moratorium on termination or disconnectio of utility service including gas and/or electric service in cases of general weather or health emergency.
Maryland	Electric Universal Service Program (EUSP): Authorized through restructuring legislation, the EUSP includes current electric bill assistance, retirement of certain old bills, and weatherization services. Its funding of $34 million per year continues but is subject to annual review and approval by the Maryland Public Service Commission (PSC) and the legislature. Eligibility: electricity customers with incomes at or below 150% FPL. Eligible customers may receive both EUSP and LIHEAP. Project Energy Assistance: A comprehensive state plan to help Maryland's working families with their energy costs. Project Energy Assistance extends the income eligibility requirements to include homes with annual income levels up to 200% of the poverty level, which is $40,000 for a family of four. Applications for the program were taken from January 15 to March 31, 2006. Universal Service Protection Program (USPP): Available to LIHEAP recipients, USPP reduces and evens out monthly utility payments by subtracting the amount of the LIHEAP benefit from a customer's yearly bill and dividing the remainder by twelve months. Those who keep on payment plans are eligible for credits from s Transitional Emergency, Medical, and Housing Assistance (TEMHA) 11 Low-inc Local energy tax dollars are given in a rebate to low-income households in two c		
Massachusetts			
Michigan	Home Heating Credit: A state tax credit that can help offset the costs of natural gas or electricity used to heat homes in the winter. The Credit is based on household income, the number of exemptions claimed and the home's actual heating costs. Special exemptions may be available to customers 65 and older and to people with disabilities.		Crisis Intervention (State Emergency Relief): As part of SER, a program that distributes financial assistance to state residents facing emergencies that threaten their health or safety, Crisis Intervention helps eligible low-income households pay for energy-related emergency services. Heating fuel or electricity payments help prevent shutoffs or restore service, while home repair payments provide the minimum necessary assistance to maintain "a decent, warm dwelling unit."

	Seasonal, Health, and Income Related Disconnection Policies	Low Income - Other
Illinois	Seasonal: Illinois prohibits disconnection of residential natural gas or electric service for nonpayment when the National Weather Service forecasts that the temperature at that location will be 32°F or below for that calendar day. The Utili Termination Bill prevent utilities from disconnecting service to any LIHEAP-eligible households for nonpayment from December 1 through March 31. Between December 1 and March 31, utilities must offer all customers who are subject to disconnection the opportunity to maintain service by making a down payment equal to 10% of the bill and paying the balance over the next 4 to 12 months. The utility must allow the customer to earn credits applicable to the overdue bill by working at a nonprofit organization or by attending school. Health: Illinois requires that natural gas and electric utilities delay disconnection of residential service for up to 30 days if a physician or other health official certifies that such an action would adversely affect the health of the customer or permanent household resident. Disconnection may be delayed for another 30 d	
Indiana	Seasonal: Indiana prohibits utilities from disconnecting residential natural gas or electric service for nonpayment from December 1 to March 15 if the customer qualifies for public assistance, whether or not the customer receives the benefit. Health: Indiana requires that natural gas and electric utilities delay residential disconnection for up to 10 days if a physician or other public health official certifies in writing that such an action would adversely affect the health of the customer or permanent household resident. Deferred Payment: Utilities are prohibited from disconnecting residential service for nonpayment if the customer can prove financial hardship or other legitimate cause of nonpayment, and if he or she fulfils the following requirements: Pays th lesser of $10 or 10% of the overdue bill and agrees to pay the balance within the next three months; Agrees to pay all undisputed future bills; Has met requirements of similar payment arrangement(s) within the last 12 months.	Legislation, since 1894, requires Indiana's 1,008 towns and townships to provide "poor relief" that can include housing, utility, food, and medical assistance. Townships are local governmental units within counties and cities, with elected boards and trustees. Property taxes fund "poor relief"; each local entity establishes spending guidelines for the funds. Universal Service Program: Beginning January 1, 2005, eligible customers of Citizens Gas and Vectren who have applied for the state's LIHEAP through local community action agencies, will automatically be enrolled in the new USP and will receive bill reductions in addition to LIHEAP. Monthly bill reductions will rang from 9% to 32% of the total bill (not including LIHEAP benefits), depending on the consumer's income level and utility provider. The pilot USP will also provide additional funding to both utilities' weatherization programs.
Iowa	Seasonal: From November through April, Iowa prohibits the disconnection of residential electric or natural gas service for nonpayment if the customer is certified eligible for LIHEAP and/ or the Weatherization Assistance Program. Iowa also prohibits the disconnection of residential electric or natural gas service for nonpayment when the National Weather Service forecasts that the temperature at that location will be 20° F or below for that calendar day. Health: The state requires utilities to delay for up to 30 days the disconnection of residential service if a physician or other public health official certifies that such an action would adversely affect the health of the customer or a permanent household resident. The delay may be extended for an additional 30 days if the physician certifies that the problem still exists at the end of the initial period. The customer is required negotiate a payment arrangement to pay the overdue balance. Deferred Payments: Utilities are required to offer deferred payment arrangements to residential customers in danger of disconnection for nonpayment, and are prohibited from disconnecting service when a customer ag	
Kansas	Seasonal/Deferred Payment: Between November 1 and March 31, Kansas prohibits regulated electric and natural gas utilities from disconnecting service to residential customers for nonpayment unless the National Weather Service forecasts temperatures of above 35°F for the 48-hour period immediately following the proposed disconnection. Customers can avoid disconnection when the temperature is above 35°F during the winter protection period (or at any othe time of the year) by paying 1/12 of the amount owed and agreeing to a deferred-payment arrangement to pay the balance within 12 months. Health: Kansas requires utilities to delay for up to 21 days disconnection of residential service if the customer notifies the utility—and the utility verifies—that such an action would adversely affect his or her health or the health of a permanent household resident. During the 21-day delay, the customer is expected to negotiate a deferred-payment arrangement to pay off the delinquent balance.	
Kentucky	Seasonal: Between November 1 and March 31, residential utility customers in Kentucky who are certified eligible for LIHEAP by the Cabinet for Human Resources, or who have incomes under 130% of poverty, are exempt from termination for 30 days beyond any termination date set by the utility. Under the winter hardship reconnection policy, which extends from November to March, electric and natural gas utilities are required to reconnect a customer's residential service if the customer obtains a certificate of need from the Cabinet for Human Resources, pays either onethird of the outstanding bill or $200 (whichever is less), and agrees to a deferred-payment arrangement. Health: Utilities are required to delay for up to 30 days disconnection of a customer's residential service whenever a physician or other public health officia certifies in writing that such an action would aggravate an existing medical or debilitating condition of the customer or any other household member. The customer is required to negotiate a deferred-payment arrangement to maintain service beyond the delay. Deferred Payment: During the winter protection dates, and at any other time of t	
Louisiana	Health: Louisiana delays for up to 63 days disconnection of residential electric or natural gas service for nonpayment if a medical professional certifies in writing that such an action would be detrimental to the customer's health or safety. The customer is required to negotiate a deferred-payment plan with the utility before the scheduled disconnection date.	
Maine	Seasonal/Low-Income: Maine prohibits utilities from disconnecting residential natural gas or electric service for nonpayment between November 15 and April 15 if the customer's account is less than three months overdue, or if the amount owed is less than $50. During these protection dates, Maine also requires regulated utilities to offer LIHEAP participants, SSI recipients, and state residents with household income at or below 185% of poverty the opportunity to pay a portion of each winter bill as it becomes due, and the remaining portion of the bill(s) in installments during the nonheating months. Health: Maine requires utilities to delay for up to 30 days disconnection of residential service for nonpayment if a physician certifies in writing that such an action would adversely affect the health of the customer or a permanent household resident. A certificate delaying disconnection can be renewed up to three times in 12 month periods. Deferred Payments: Maine prohibits utilities from disconnecting residential service for nonpayment whenever a customer pays a "reasonable" portion of the	
Maryland	Seasonal/Low-income: Customers of Maryland's Utility Service Protection Program are protected from utility disconnections year-round (see program description above). For all other residential customers, utilities cannot disconnec residential service between November 1 and March 31 unless they can prove that such an action will not endanger the health of any member of the customer's household. Health: Maryland requires natural gas and electric utilities to delay for up to 30 days disconnection of residential service if a physician certifies that such an action would adversely affect the health of the customer or other household resident. The customer is required to negotiate a deferred payment arrangement to extend service beyond the 30-day delay.	
Massachusetts	Seasonal: Between November 15 and March 15, Massachusetts prohibits disconnection of residential natural gas or electric service—if such service either provides heat or operates the heating system—for any household that is unable to pay an overdue bill because of financial hardship. In 2006 the moratorium on disconnection of residential natural gas or electric service was extended until April 30, 2006. Health/Age: Massachusetts prohibits disconnection of natural gas or electric service for nonpayment whenever a customer presents certification that the household contains either a seriously ill member or a child under 12 months old. Utility companies may not shut off services without written approval to households where all residents are 65 years of age or older. Certifications of serious illness may be renewed monthly, or quarterly in cases of chronic illness. Certifications of infancy remain in effect until the child exceeds 12 months of age.	
Michigan	Seasonal/Winter Protection Plan: The Michigan Public Service Commission requires state-regulated utilities to provide winter protection programs that help low-income and senior citizen customers avoid service disconnections and high utility bill payments from November through March. State residents with household incomes at or below 200% of poverty are eligible for this program. Residents meeting any of the following criteria are also eligible: Age 65 or older; Receiving Michigan Department of Human Services cash assistance; Receiving food stamps or Medicaid. The program requires participants to make regular payments throughout the protection period and pay the balance in installments between April and October. Health: Michigan requires utilities to delay for up to 21 days disconnection of residential service if a physician or other public health official certifies that such an action would adversely affect the health of the customer or other permanent household resident.	

UTILITY

	Low Income Rate Assistance	Low Income Energy Efficiency
Illinois	ComEd - Rate Relief Program (3 programs) - [1] Summer Assistance Program: A one-time $30 credit for Low Income Home Energy Assistance Program participants with household incomes up to 200% of the poverty level, or $40,000 for a family of four. [2] Residential Rate Relief Program: A one-time credit of up to $240 for customers who experienced a higher-than-average rate increase of 30% or more. This program is for households with incomes up to 200% of the poverty level, or $40,000 for a family of four. [3] Residential Hardship Fund: Variable grants of up to $1,000 to offset rate increases for people with special circumstances and hardships. Customers with household incomes up to 400% of the poverty level, or $80,000 for a family of four, may be eligible, if they identify a special hardship issue such as medical expenses, military service, seniors requiring in-home care or grandparents raising minor grandchildren, or a person in the home with a disability. Verification of hardship will be required. Springfield City Water Light & Power - Senior Citizen Discount Rate A 10% disc	
Indiana	Northern Indiana Public Service Co. (NIPSCO) - Winter Warmth LIHEAP eligible customers or customers with a financial hardship can receive up to $400 that can be applied to both the payment of delinquent utility bills and natural gas deposits. Additionally, NIPSCO will limit natural gas deposit payments for LIHEAP eligible customers to $150 and $300 for other non-LIHEAP eligible customers determined to have a financial hardship.	Duke Energy - Low-Income Weatherization Program Offered through a partnership with the state of Indiana, the program is designed to provide energy saving installations and energy education at no cost to our customers who qualif for the weatherization or heating bill assistance as part of the state or federal programs. Northern Indiana Public Service Company (NIPSCO) - Home Energy Solutions Weatherization Program: Qualifying homeowners will receive a home energy assessment at no cost. Depending on the results of the assessment, your home may receive one or more of the following energy efficiency improvements at no cost: replacing an inefficient furnace or water heater with a more efficient appliance; adding insulation, air sealing, and/or installing energy-saving devices such as water-saving faucet aerators and shower heads. The program will be available through April 1, 2008, or while funds last. Vectren - Share the Warmth: Vectren matches all public donations, up to an annual total of $200,000. Funds are distributed annually to the Indiana Low Income Weatherization Assistance Program. Weatherization services vary with
Iowa		Aquila: Provides CAP agencies with funding for weatherization recruitment and installation. Weatherization improvements include floor, ceiling, and wall insulation; band joist; water heating measures (pipe wrap, water heater blankets low-flow showerheads, and faucet aerators); and air infiltration measures. MidAmerican Energy (2 programs) - [1] Funding for low-income weatherization is available to customers year-round. MidAmerican's energy efficiency department with assistance from the Iowa Department of Human Rights, administers the program and distributes funds specifically earmarked for home improvements to low-income customer homes.[2] HomeCheck: Free energy assessment for homes built before December 31, 1994 includes installation of water heater blanket, pipe insulation, low-flow faucet aerators and shower heads, waterbed mattress pad and energy-efficient light bulbs.
Kansas		
Kentucky	Louisville Gas & Electric - Home Energy Assistance: Provides a year-round fixed credit that varies by month and is based on the household's income, size and utility bills for the previous 12 months, an adjustment for monthly normal heating degree days, and any significant changes in utility pricing. The credit can be applied to arrearages. Customers with household income at or below 110% of federal poverty guidelines must have a minimum monthly household income of $100 and household utility arrearages under $700 and to participate. Kentucky Utilites - Home Energy Assistance: Eligible customers will receive a fixed amount of $294 per year in seven monthly installments of $42 that are applied to the current bill. The credit will be applied to bills during peak heating a cooling months and cannot be used to reduce arrearages. Customers must use electric heat and have household income at or below 110% of federal poverty guideline to participate.	Duke Energy: Eligible households receive a furnace/heat pump clean and tune, energy efficient light bulbs, energy saving tips and, if needed, hot water heater wrap, weather-stripping and pipe wrap. Depending on the condition of the home and its energy usage, other services may include duct sealing, wall and attic insulation and other air leakage sealing measures. Louisville Gas & Electric - WeCare: Participants receive a walk-through inspection and energy education. Many will receive HVAC and water heater system inspection, air sealing and attic insulation. Eligibility: income 125% of the federal poverty level or less, priority is given to elderly and disabled. Kentucky Utilities - WeCare: All participants receive a walk-through inspection and energy education. Many will receive HVAC and water heater system inspection, air sealing and attic insulation. Eligibility: income equal to or less than 125% of the federal poverty level, priority is given to elderly and disabled.
Louisiana	Entergy Gulf States Utilities, Inc. - Senior Discount Program Waiver of $6.00 monthly customer charge for customers who are 65 or older and have an annua income less than $10,000. Entergy New Orleans - Elderly and Handicapped Emergency Assistance Fund Entergy provides funding for the program, that is administered by the New Orleans Council on Aging and Total Community Action, to address the needs of the disadvantaged through direct energy assistance.	Entergy LA and Entergy New Orleans Caulking, hot water jackets, door strips, outlet plugs, solar screens, refrigerator replacement and general repairs.
Maine	Low-Income Assistance Program (LIAP): Maine's transmission and distribution utilities are required to create or maintain a LIAP to make electric bills more affordable for LIHEAP-eligible customers. The Maine State Housing Authority administers, implements and coordinates the statewide plan and the individual LIAPs in conjunction with its delivery of LIHEAP. The fund amounts to approximately $5.7 million yearly. Bangor Hydro Electric (2 programs) - [1] LIHEAP-eligible customers may qualify for a rate discount. Depending on income, the percentage of the discount will vary based on kWh usage.[2] Emergency Assistance Program: Limited to AFDC families, or families with children under the age of 18, who may be eligible for AFDC. One of the program's functions is to assist families in paying past due energy-related costs in order to avoid being shut-off. Central Maine Power - Electricity Lifeline Program Offers qualified low-income customers a credit on their electric bill. This credit is based on household income and estimated electricity usage and is applied to your bill for the same amount e Maine Public Service Co. - PowerPact LIHEAP-eligible customers who keep cur	Low Income Refrigerator Replacement: A collaborative effort involving Efficiency Maine, the Maine State Housing Authority and the state's Community Action Programs. The program replaces inefficient refrigerators and installs energy efficient lighting in the homes of qualified low-income consumers. Families or individuals that have incomes at or below 150% of federal poverty guidelines or incomes at or below 170% of federal poverty, if that household has an elderly member or a child under 24 months, may be eligible for the program. Community Action Programs deliver the services. Central Maine Power - Low-Income Energy Management Program Electric water heater and pipe insulation and water conservation measures.
Maryland	The largest utility, Baltimore Gas and Electric, and many smaller utilities offer deposit, reconnect fee and application fee waivers to qualifying customers. Baltimore Gas and Electric - Customer Assistance Maintenance Program (CAMP): Under the CAMP, customers who participate in the Universal Service Protection Program can qualify to earn monthly bill credits ranging from $7 to $12. The amount of credit is based upon income. Allegheny Power - Energy assistance plans Washington Gas Light Company - Residential Essential Service (RES) MEAP-eligible residents who use natural gas for home heating and who are current on their utility bills may be eligible to receive discounts on a portion of their Washington Gas bills during the winter heating season. The discount could be worth up to $135.	Allegheny Power - Energy assistance plans Columbia Gas - Low Income Weatherization Program A free program, for customers with low incomes and higher gas usage, that identifies an energy picture of a home and takes action to seal up areas of heat loss.
Massachusetts	Over a dozen gas, electric and combination IOUs offer utility rate discounts totaling nearly $40 million per year and ranging from 20% to 42% off the low-income customer bill. These discounts were negotiated during the past two decades and were required to continue under Massachusetts' restructuring legislation. Households earning less than 175% of Federal Poverty Guidelines, or receiving one of several means tested programs, including LIHEAP, Food Stamps, TANF and SSI are eligible. NSTAR - R2 Discount Rate: Discount rate for customers who receive certain government means-tested benefits or qualify for fuel assistance. KeySpan Energy Delivery (Boston, Essex and Colonial Gas Companies) You may receive a discount if you are a low-income residential customer and participate in the following public assistance programs: SSI, AFDC, Medicaid, E.A.E.D.C., Food Stamps, Refugee Resettlement, Fuel Assistance or Mass Veterans Service Benefits. KeySpan Energy Delivery - On Track On Track works with 350 low-income 1-2 family heating customers, who are receiving public assistance, to help them resolve financial difficulties. Each participant receives a financial and energy hor Massachusetts Electric: Monthly discount for customers with income at or below Nantucket Electric: Monthly discount for customers with income at or below 175	Customers of Massachusetts regulated electric and gas companies who receive the low-income discount rate may also be eligible for free energy efficiency services that may include energy audits, electric baseload measures, appliance efficiency services, attic and wall insulation, air sealing and heating system replacement. Berkshire Gas - HEARTWAP: This grant program provides low-income, fuel assistance-eligible homeowners with assistance for: Heating system repair/replacement services; Heating system cleanings; Free energy, health and safety audit; Free attic and/or side-wall insulation, air sealing, weather-stripping and other winterization energy repairs. City of Boston (2 programs) - [1] HeatWorks: The Department of Neighborhood Development has partnered with Keyspan Energy Corporation and Action for Boston Community Development, Inc. (ABCD), to create HeatWorks, a program for eligible senior homeowners who are 60 years of age and older, who are owner-occupants of a residential 1-4 family property in the City of Boston, and whose income doe not exceed 80% of median family income as determined by KeySpan Energy Delivery Free weatherization services for customers on the R3 Massachusetts Electric - Energy Efficiency and Conservation Programs Special NSTAR (2 programs) - [1] MassSAVE: Energy efficiency specialists will answer
Michigan	Arrearage forgiveness and deposit and fee waivers are provided by utilities that participate in the state's automated positive billing system and other payment plans. Under positive billing, a participating household must pay a percentage of its monthly assistance grant to its utility. Winter Protection Plan: This plan protects senior and low-income customers of Commission-regulated natural gas and electric companies, rural electric cooperatives and alternative electric suppliers from electric or natural gas service shut-off and high utility payments between December 1 and March 31. Persons qualify for the plan if they meet any of the following criteria: are age 65 or older, or receive Michigan Family Independence Agency cash assistance, or receive Food Stamps or Medicaid, or have a household income at or below 200% of poverty level. Winter Protection allows eligible low income customers to make monthly payments of at least 7% of their estimated annual bill, along with a portion of any past-due amount, December through March, and avoid shut-off during that time even if their bills are higher. Eligible senior citizens participating in Winter Protec	

CHARITABLE

	Emergency Charitable Assistance Programs
Illinois	AmerenUE, AmerenCIPS, AmerenCILCO - Dollar More Funds pay for a wide variety of home energy bills including electric, gas, oil and propane. All Dollar More contributions go to the needy through a network of human services agencies. Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. ComEd - Power Up: Provides a one-time energy assistance grant of up to $400 to assist families with incomes between 150 to 200% of the federal poverty level who are not eligible for LIHEAP. The program also supports a separate Emergency Fund to assist households with incomes below 200% of the poverty level that may not be eligible for LIHEAP. Illinois Power (AmerenIP) - Warm Neighbors Provides bill payment assistance and weatherization for qualifying customers who generally do not qualify for federal or state heating assistance. The program begins on December 1 and ends May 31. To qualify, applicants must meet one of the following conditions: total household income at or below 200% of poverty level or demonstrate temp Mid-American Energy Company - I CARE I CARE assists those who are unemployed, living on fixed or low incomes or experiencing Nicor Gas - Sharing Program Provides one-time annual grants to qualified residential customers. Administered by the Salvation Army Peoples Energy Corporation - Share the Warmth This program provides up to $200 in assistance, per household, to eligible custome Wayne-White Counties Electric Cooperative - WORKS: Grants are available for individuals in need and for 501(c)3 organizations. Th
Indiana	Winter Assistance Fund: This fund, administered by the United Way, provides financial assistance to families who are not eligible for other energy assistance programs. Central Indiana Power - Operation Roundup Customer donations are used to assist people with medical care or equipment, food, clothing, housing, etc. No funds will be used to pay electric bills. A thirteen member board of trustees administers the funds. Citizens Gas - Warm Heart, Warm Home Foundation: Assists families and individuals faced with a crisis. Citizens Gas matches customer donations up to $50,000. Decatur County REMC - Operation Roundup Customer donations provide charitable assistance to individuals, families and organizations. Funds will not be used for utility bill payments. Duke Energy - Helping Hand Low-income customers who are at least 60 years old or disabled and who meet certain income guidelines may receive a one-time $60 payment. Beginning February 1, eligible customers may apply for Helping Hand by printing out an application on the Duke Energy Web site or by calling 1-800-521-2232. Indiana Michigan Power - Energy Share Energy assistance for low-income customers who may be having trouble paying their electric Northeastern REMC - Operation Roundup Customer donations are placed in a trust fund and administered by the board of trustees o Northern Indiana Public Service Company - Gift of Warmth A fund created to assist NIPSCO customers who typically don't qualify for Parke County REMC - Operation Roundup Customer donations are placed in a trust fund and administered by an independent Board South Central Indiana REMC - Operation Roundup® Customer donations are placed in a trust fund and administered by the Board of
Iowa	EMBRACE IOWA: A program sponsored by the Des Moines Register that helps Iowans who need immediate financial assistance and are unable to receive help through other existing programs. All applications must be made at an Iowa Community Action Agency. Alliant Energy - Hometown Care Energy Fund Recipients include older citizens on fixed incomes, families struggling with medical problems or a job loss, and eligible people still trying to pay off last winter's high heating bills. Funds are administered by regional community action programs. Alliant Energy adds a 25% matching gift for every customer contribution. Aquila - Aquila Cares Aquila adds 50 cents to every dollar contributed by our customers, to a total contribution by Aquila of up to $100,000. Local assistance agencies determine customer eligibility and distribute funds. Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills in Lee county. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. Contact Southeast Iowa Community Action Access Energy Cooperative - ReCare: Customer donations fund an energy assistance program to assist the elderly and other low in Butler County REC - RECare: Customer donations provide local community action agencies with funds to help low-income families p Chariton Valley Electric Cooperative - RECare: Customer donations provide local community action agencies with funds to help low-i Consumers Energy - Operation Round-Up® Members donate small change each month to cooperative members needing economic East-Central Iowa REC - RECare: Customer donations provide local community action agencies with funds to help low-income famili Harlan Municipal Utilities - Project Share The Project Share program is a voluntary contribution program. A committee consisting of r Harrison County Rural Electric Cooperative - RECare: Members provide funds that are distributed by local community action agencie Iowa Lakes Electric Cooperative (2 programs) - [1] Operation Round-Up® Member donations provide funds to organizations and indi
Kansas	Emergency Energy Fund Provides up to $100, applicants are eligible to receive funds once every two years. Administered by the Salvation Army, available in Reno County. HeatShare: Provides payments toward heating and air conditioning bills and can go toward electricity, natural gas, propane, fuel oil or wood bills throughout Kansas. Where sufficient funds are available, grants are available for emergency repairs to furnaces, air conditioners, hot water heaters and other energy related equipment. Assistance may also be available for repairs to broken windows and doors. The elderly and disabled are given priority where funds are limited. Aquila - Aquila Cares Funds for utility bills or repairs to vital heating or cooling equipment. Contact a state, county or community agency for assistance. Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. Kansas City Power & Light - Dollar Aide Customer donations help people in need pay their utility bills year-round, regardless of wheth Kansas Gas Service - Gift of Warmth: Customer contributions are distributed by the Salvation Army to qualifying families. Pioneer Electric Cooperative, Inc. - We Care: Employees and Trustees participating in the program make a donation from each payc Westar Energy - Project Deserve: Offers bill payment assistance of up to $200 once a year. Applications can be picked up at the loca
Kentucky	Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. Duke Energy - WinterCare Fund Eligible customers will receive a one-time payment available November through March or until funds are depleted. Louisville Gas & Electric - Winterhelp Helps low-income customers pay their heating bills. LG&E will match residential customers' donations to Community Winterhelp on a dollar-for-dollar basis through April. Applications are accepted in early February of each year at the Community Ministry location nearest the applicant's home. West Kentucky Rural Electric Cooperative Corporation - E.N.U.F. (Emergency Needline Utility Funds) The Calloway County Needline office or other agencies familiar with emergency needs distribute an emergency fund created by customer donations.
Louisiana	American Electric Power - Neighbor to Neighbor AEP matches customer contributions dollar for dollar up to $2500 per month. Assistance is limited to $100 per customer per year. The United Way office in Shreveport, La. administers the program through various agencies in AEP's service territory. To apply, customers must provide a disconnection notice to the local agency administering the funds. Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. Beauregard Electric Cooperative, Inc. - Share Program Customer donations are distributed among the area parishes through each local community action agency to assist needy families. CenterPoint Energy (2 programs) - [1] Energy Assistance Program (south Louisiana) Customers can donate $1 to help low-income and elderly customers pay their gas bill by checking a box on their bill. The funds are administered by the American Red Cross and local assistance agencies. [2] Good Neighbor Fuel Fund (north Louisiana) The funds are administered by local assistance agencies a Dixie Electric Membership Corporation - Operation Round-UP®: An assistance program funded by DEMCO members who have their
Maine	Maine Sea Coast Mission: Provides emergency assistance for heat, electricity, food and other emergency circumstances for island and coastal communities from mid- to Downeast coastal Maine.
Maryland	Delmarva Power (Conectiv) - Good Neighbor Fuel Fund Delmarva matches customer contributions with a donation from shareholders. A household must first apply for LIHEAP. Funds are administered by the Salvation Army. Fuel Fund of Central Maryland, Inc. BG&E gives $1 in bill credits for every $2 paid by the customer and the Fuel Fund of Central Maryland (FFCM). The Fuel Fund also helps customers that use oil or other fuel sources. FFCM is an umbrella organization compris of local fuel funds in Baltimore City and Anne Arundel, Baltimore, Carroll, Harford and Howard counties. Washington Area Fuel Fund The Washington Area Fuel Fund, operated by the Salvation Army, aids customers who need assistance paying their home heating bills. The Victorine Q. Adams Fuel Fund The Victorine Q. Adams Fuel Fund (formerly the Baltimore City Fuel Fund) was organized in 1979 with a seed grant of $10,000 from Baltimore Gas and Electric. It pays up to $125 to clients facing shut-offs, provides utility credits toward arrearages and operates an emergency oil program, which provides 100 gallons of oil to eligible families at nominal cost. Allegheny Power - Community Energy Fund Funded by private donations in partnership with Allegheny Power. The program provides Columbia Gas - HeatShare: Provides energy grants to customers for use in offsetting arrears or restoring service to terminated utility Southern Maryland Electric Coop - Tri-County Fuel Fund Funded by the Southern Maryland Electric Company's Project Match, privat
Massachusetts	Good Neighbor Energy Fund Utilities and utility customers fund the Good Neighbor Energy Fund across Massachusetts. Benefits provide a maximum $275 payment toward energy bills for households with incomes between 200 - 275% of federal poverty level. Administered by the Salvation Army, the fund helps customers pay their energy bills, especially people in financial crisis who may not qualify for other means of fuel assistance. Each year the Fund opens December 1 for clients with an emergency heating situation and January 1 for all other clients.
Michigan	The Heat and Warmth Fund (THAW): An independent non-profit organization, THAW distributes funds for bill-payment assistance across the state and promotes energy conservation, weatherization and energy efficiency education. THAW partners with several utility companies, who provide funding to administer and operate the program. Most match customer and other donations dollar for dollar and all contributions go directly to low-income bill payments. Consumers Energy - PeopleCare: Begun in 1983, PeopleCare is a partnership between Consumers Energy and The Salvation Army to help Michigan households who may not qualify for other assistance yet are struggling to make ends meet. Charitable donations from Consumers Energy customers and employees allow The Salvation Army to extend material assistance to families, ranging from food to transportation to medical needs. Consumers Energy also donates PeopleCare bill credits for its low-income gas and electric customers, which are applied directly to a customer's bill based on The Salvation Army caseworker assessment and authorization. Cherryland Cooperative - Operation Round Up® Customer donations for Operation Round Up® go to the locally administrated Comm Lansing Board of Water & Light - Pennies for Power Program Customer donations fund the Pennies for Power Program that provides The Salvation Army The Salvation Army provides utility assistance throughout the State of Michigan. Over 120 caseworkers, working Tri County Electric - People Fund and Operation Round Up® Customer donations provide funds for individuals and community organi

	FEDERAL								STATE / LOCAL					UTILITY		CHARITABLE
	LIHEAP FY2008 Funding	LIHEAP Income Eligibility Level	LIHEAP FY2007 Benefit	LIHEAP Households Served (FY2006/07 Estimate)	% of Eligible HHs ≤150% FPL Receiving Energy Assistance (2006)	Weatherization Assistance Program (WAP) Benefit (FY2006)	WAP Eligibility (FY2006)	WAP Households Served (FY2006)	Low Income Rate Assistance	Low Income Energy Efficiency	Low Income Emergency Assistance	Seasonal, Health, and Income Related Disconnection Policies	Low Income - Other	Low Income Rate Assistance	Low Income Energy Efficiency	Emergency Charitable Assistance Programs
Minnesota	$ 78,362,555	50% State Median Income	Heating: $100 min, $511 avg, $1200 max	Heating: 120,571	13.8%	Avg. benefit: $2,312	50% State Median Income	3,179			The Minnesota Department of Human Services provides funds for emergency crisis assistance to households who would otherwise be without heat.	Seasonal: From October 15 to April 15, Minnesota prohibits disconnection of residential natural gas or electric service for nonpayment if the customer meets any of the following requirements: [illegible] Health: Minnesota prohibits utilities from disconnecting residential service for nonpayment if a physician certifies that such an action would adversely affect the health of the customer or a permanent household resident. Deferred Payments: Before disconnecting residential service for nonpayment, [illegible]		Xcel Energy: As a result of legislation passed in 1994, Minnesota requires that electric companies serving over 200,000 residential customers provide a 50% discount for low-income customers on the first 300 kilowatt hours consumed each month. [illegible] The average benefit is $108 per household.	Energy Conservation Improvement required by legislature of regulated utilities. [illegible] CenterPoint Energy/Minnesota [illegible] Minnesota Energy Resources [illegible] Otter Tail Power Company - House Therapy Program [illegible] Xcel Energy (2 programs) [illegible]	Reach Out for Warmth (ROFW): Established in 1992 by the Minnesota State Legislature, the Department of Economic Security's Energy Program Unit administers this year-round program [illegible] HeatShare: A "last resort" program funded through customer contributions from Minnesota utilities and is administered by The Salvation Army. [illegible] Agralite Electric Cooperative - Operation Round Up [illegible] Benco Electric Cooperative [illegible] Farmers Union Cooperative - Operation Roundup [illegible] Minnesota Valley Cooperative Light and Power Association - Operation Round Up [illegible] Wright-Hennepin Cooperative Electric Association - Operation Round Up [illegible]
Mississippi	$ 14,670,325	150% Federal Poverty Level	Heating and Cooling: $250 avg	Heating: 61,750; Cooling: 34,300	4.4%	Avg. benefit: $2,464	125% Federal Poverty Level	669				Seasonal: From December 1 to March 31, Mississippi prohibits disconnection of residential electric or natural gas service for nonpayment if the customer [illegible] Seasonal/Health: During the winter protection period, utilities are prohibited from disconnecting residential utility service if a licensed physician certifies that discontinuance of heating service to the customer would create a medical emergency for the customer or a member of the customer's household.		Mississippi Power: Monthly base charge is waived ($0.46 per day) for eligible low income and elderly customers receiving SSI or AFDC.	Entergy Mississippi - Helping Hands: [illegible]	Atmos Energy - Sharing the Warmth [illegible] Entergy (2 programs) [illegible] Mississippi Power - Project Share [illegible] Mississippi Valley Gas - Share the Warmth [illegible] Tupelo Water & Light - Tupelo Cares [illegible]
Missouri	$ 45,761,931	125% Federal Poverty Level	Heating: $65 min, $301 max; Cooling: $300 max	Heating: 124,048	10.1%	Avg. benefit: $2,744	150% Federal Poverty Level	2,312				Seasonal: From November 1 to March 31, Missouri prohibits regulated utilities from disconnecting residential gas or electric service [illegible] Health: [illegible] Deferred Payments: [illegible]		Empire District Electric Company - Empire's Action to Support the Elderly (EASE) [illegible] Independence Power & Light Department - Independence Rate Assistance Program (IRAP) [illegible]	AmerenUE (2 programs) [illegible] Community Services League [illegible] Laclede Gas Company [illegible] Missouri Public Service (MPS) [illegible]	HeatShare: [illegible] Heat-Up St. Louis [illegible] Aquila [illegible] Boone County [illegible] Co-Mo Electric Coop [illegible] Crawford Electric Coop [illegible] Cuivre River Electric Coop [illegible] Empire District Electric Co. - Project Help [illegible] Intercounty Electric Coop Association - Operation Round-Up [illegible]
Montana	$ 14,516,847	150% Federal Poverty Level	Heating: $51 min, $392 avg, $2123 max	Heating: 20,200	14.4%	Max. benefit: none	150% Federal Poverty Level	1,503				Seasonal: Between November 1 and April 1, Montana prohibits utilities from disconnecting service to residential customers [illegible] Health: [illegible] Deferred Payments: [illegible]		NorthWestern Energy [illegible] Flathead Electric Cooperative [illegible] Hill County Electric - Universal Services Benefit Program [illegible] Lincoln Electric Co-op [illegible] Missoula Electric Cooperative [illegible] Park Electric Co-op - Senior Income Eligible Discount [illegible]	NorthWestern Energy - Free Weatherization Program [illegible] Sun River Electric Coop [illegible]	Northwestern Energy Share [illegible] Flathead Electric (3 programs) [illegible] Hill County Electric - Energy Share [illegible]
Nebraska	$ 18,180,421	116% Federal Poverty Level	Heating: $110 min, $253 avg, $684 max; Cooling: $68 min, $134 avg, $198 max	Heating: 32,650; Cooling: 6,170	9.9%	Avg. benefit: $2,826	150% Federal Poverty Level	1,292				Nebraska has no state-mandated weather-related disconnection policies.				Aquila (2 programs) [illegible] Cuming County Public Power District - Operation Round Up [illegible] Hastings Utility - Share Warmth [illegible]
Nevada	$ 3,886,640	150% Federal Poverty Level	Heating or Cooling: $180 min, $923 avg, no max for heating and electricity	Heating: 18,166	4.6%	Max. benefit: $4,000	150% Federal Poverty Level	994	Arrearage Assistance: [illegible]	In August 2001, a Universal Energy Charge (UEC) was imposed on customers [illegible]	Emergency Assistance (Welfare Set-Aside Program) [illegible]	Seasonal: Nevada prohibits utility disconnections in cases of extreme weather, [illegible] Health: [illegible] Deferred Payments: [illegible]		Lincoln County Power District [illegible] Sierra Pacific Power Company [illegible] Valley Electric Association - Lighthouse Assistance Program [illegible]	Southwest Gas Corporation [illegible]	Nevada Power - Project REACH [illegible] Sierra Pacific Power Company - Special Assistance Fund for Energy (SAFE) [illegible] Southwest Gas - Energy Share [illegible]
New Hampsh	$ 15,671,860	185% Federal Poverty Level	Heating: $120 min, $553 avg, $975 max	Heating: 32,581	1.7%	Avg. benefit: $2,600	185% Federal Poverty Level	1,053			An 1840's statute requires towns and cities to provide emergency welfare services to the poor, [illegible]	Seasonal: Between December 1 and April 1, utilities in New Hampshire must obtain approval from the Public Utilities Commission before disconnecting [illegible] Health: [illegible] Deferred Payments: [illegible]		Beginning October 1, 2002, the tiered-discount program (TDP) [illegible] Granite State Electric [illegible] KeySpan Energy Delivery [illegible] New Hampshire Electric Co-op - Electric Assistance Program [illegible] Northern Utilities [illegible]	As of June 1, 2002, electric utility customers can take advantage of statewide energy efficiency [illegible] Granite State Electric - Home Energy Assistance [illegible] KeySpan Energy Delivery - Low-Income Weatherization Program [illegible] New Hampshire Electric Coop [illegible] Public Service Company of New Hampshire [illegible]	Neighbors Helping Neighbors: [illegible] New Hampshire Electric Cooperative - Project Care [illegible]
New Jersey	$ 76,864,515	175% Federal Poverty Level	Heating: $115 min, $326 avg, $1138 max; Cooling: $100 flat benefit for medically necessary cooling	Heating: 155,914	11.3%	Max. benefit: $5,000	150% Federal Poverty Level	3,005	Lifeline Assistance Program: [illegible] Universal Service Fund: [illegible]	New Jersey Comfort Partners: [illegible]		Seasonal/New Jersey Winter Termination Program: [illegible] Health: [illegible]		Lifeline Assistance Program: [illegible] Universal Service Fund: [illegible]	New Jersey Comfort Partners: [illegible]	New Jersey SHARES (Statewide Heating Assistance and Referral for Energy Services) [illegible] New Jersey Natural Gas - Gift of Warmth [illegible]
New Mexico	$ 10,360,042	150% Federal Poverty Level	Heating and Cooling: $38 min, $240 max	Heating and Cooling: 62,269	11.0%	Max. benefit: $2,826	125% Federal Poverty Level	1,615				Seasonal: Between November 15 and March 15, New Mexico delays disconnection of residential natural gas or electric service for nonpayment [illegible] Health: [illegible] Deferred Payments: Utilities are prohibited from disconnecting a customer's natu[illegible]				Public Service Company of New Mexico - Good Neighbor Fund [illegible] El Paso Electric - Project Care [illegible] Bernalillo County (3 programs) [illegible] Storehouse West [illegible]
New York	$ 250,974,273	60% State Median Income	Heating: $165 min, $270 avg, $440 max	Heating: 844,530	9.6%	Max. benefit: $4,000	60% State Median Income	11,831				Seasonal: Between November 1 and April 15, utilities in New York seeking to disconnect service [illegible] Health: [illegible] Income: [illegible] Deferred Payments: [illegible]	A Home Energy Allowance is provided to public assistance recipients [illegible]	New York's eight investor-owned utilities, and one municipal power authority, have low-income energy programs [illegible] Consolidated Edison (2 programs) [illegible] Niagara Mohawk Power Corporation - Affordability Payment Plan [illegible]	New York Energy $mart - Assisted Home Performance with ENERGY STAR [illegible] Consolidated Edison - EmPower New York [illegible] Long Island Power Authority [illegible]	Central Hudson Gas & Electric - The Good Neighbor Fund [illegible] KeySpan (2 programs) [illegible] National Fuel Gas Company - Neighbor for Neighbor Heat Fund [illegible] New York State Electric and Gas - Project Share [illegible] Niagara Mohawk Power Corporation - Care and Share [illegible] Orange and Rockland Utilities [illegible] Rochester Gas and Electric Corporation [illegible]
North Carolina	$ 37,730,144	Heating and Cooling: 110% Federal Poverty Level; Crisis: 150% Federal Poverty Level	Heating: $25 min, $57 avg, $89 max; Cooling: $114 avg, $300 max	Heating: 233,620	9.5%	Avg. benefit: $2,744	150% Federal Poverty Level	3,996				Seasonal: From November 1 through March 31, utilities in North Carolina must seek approval of the Public Utilities Commission before disconnecting residential natural gas or electric service [illegible] Deferred Payments: [illegible]			Duke Energy: Typical services for eligible customers include: sealing air leaks, installing insulation, [illegible]	Albemarle Electric Membership Corp - Operation Round Up [illegible] Cape Hatteras Electric - Roundup Program [illegible] Carteret-Craven Electric Coop - Operation Roundup [illegible] Central Electric Membership Corp. - Member Cares [illegible] Dominion North Carolina Power - EnergyShare [illegible] Duke Power (2 programs) [illegible]
North Dakota	$ 15,769,687	60% State Median Income	Heating: $578 avg, no max benefit, client must make co-payment based on income in relation to heating costs	Heating: 15,147	16.0%	Avg. benefit: $2,900	60% State Median Income	1,454				Health: North Dakota does not have a winter disconnection policy. [illegible] Seasonal: [illegible]	Qualifying households can get a voucher for up to $300 [illegible]			Energy Share [illegible] Capital Electric Cooperative - Operation Roundup [illegible] Dakota Valley Electric Cooperative - Operation Round Up [illegible] Mountrail-Williams Electric Cooperative - Operation Round Up [illegible] Nodak Electric Cooperative - Operation Roundup [illegible] Northern Plains Electric Cooperative - Operation Round Up [illegible]

	FEDERAL								STATE / LOCAL					UTILITY		CHARITABLE
	LIHEAP FY2008 Funding	LIHEAP Income Eligibility Level	LIHEAP FY2007 Benefit	LIHEAP Households Served (FY2006/07 Estimate)	% of Eligible HHs ≤150% FPL Receiving Energy Assistance (2006)	Weatherization Assistance Program (WAP) Benefit (FY2006)	WAP Eligibility (FY2006)	WAP Households Served (FY2006)	Low Income Rate Assistance	Low Income Energy Efficiency	Low Income Emergency Assistance	Seasonal, Health, and Income Related Disconnection Policies	Low Income - Other	Low Income Rate Assistance	Low Income Energy Efficiency	Emergency Charitable Assistance Programs
Ohio	$ 101,350,902	175% Federal Poverty Level	Heating: $72 min, $298 avg, $520 max; Cooling: $200 max for utility bills.	Heating: 359,802; Cooling: 36,683	13.6%	Avg. benefit: $3,250	150% Federal Poverty Level	6,207	Percentage of Income Payment Plan (PIPP): Ohio's regulated gas and electric utilities are mandated to participate in the statewide PIPP. Low-income customers who heat with natural gas pay 10% of their monthly income to their gas company and 5% to their electric company. Those with incomes at or below 150% of federal poverty guidelines (FPG) pay 3% instead of 5% to their secondary source of heat. If their utility provides both gas and electric, or if they heat with electricity, they pay 15% of income to the one utility. Eligibility: must receive primary or secondary heat source from a company regulated by the Public Utilities Commission of Ohio, total household income must be 150% FPG or below, and, if eligible, must apply for all energy assistance programs. PIPP is administered by the Ohio Department of Development's HEAP (or LIHEAP) office. Winter Reconnect Program: Allows most households that have been disconnected or are threatened with disconnection due to non-payment of a utility bill to have service restored during the winter months by paying either the total amount they owe or $175, whichever is less, plus a reconnection fee of no more Ohio Energy Credit (OEC) Program: Permanently disabled, 65-years-or-older c	The Electric Partnership Program (EPP) was provided for under Ohio's 1999 electric restructuring legislation and is funded by the electric universal service rider. Its goal is to reduce electric consumption by households that participate in the state's Percentage of Income Payment Plan (PIPP). The program is targeted to high consumption, high arrears PIPP households and is composed of two types of programs: A baseload efficiency program which audits lighting, appliances and all other uses of electricity not related to heating and installs appropriate measures; and, A weatherization program for those who heat with electricity and who have moderate to high usage. This program adds insulation, performs heating system inspections and addresses health & safety measures. The EPP began operations in March 2002 and is administered by the Ohio Office of Energy Efficiency. In addition to programs offered by electric utilities through EPP, gas utilities also provide energy efficiency programs. LIHEAP funds transferred to the Ohio Office of Energy Efficiency are matched with utility funds to allow local providers		Seasonal: From November 1 to April 15, the Ohio Winter Protection Plan requires utilities to add 10 extra days to the customary 14 days notice given to low-income residential natural gas or electric customers facing service disconnections. The plan also prohibits natural gas or electric service disconnections for utility customers with incomes at or below 150% of poverty who are enrolled in the state's Percentage of Income Payment Plan. From October 22 to April 12 , the winter reconnect rule allows residential customers who are facing natural gas or electric service disconnects - or who have already had their service disconnected—to pay a minimum of $175 and agree to a payment plan to have service maintained or restored. Health: Ohio requires utilities to delay disconnection of residential natural gas or electric service for nonpayment if such an action is certified by a medical professional to be dangerous to health. Disconnections are also prohibited if such actions would make operation of necessary medical or life-support equipment impossible or impractical. Medical certificates may be renewed twice Deferred Payments: Utilities are required to offer customers in danger of disconn Low-Income: Utilities are prohibited from disconnecting residential service at any		Dayton Power & Light (2 programs) - [1] Percentage of Income Payment Plan Credit Program: Customers who have been on the PIPP program for one year and have more than 12 months PIPP arrears may be eligible for PIPP credits. The amount of credit is based on the total 12 months arrears. This credit is applied to the outstanding balance and not to the current installmen[2] Fresh Start: An arrearage-crediting program for customers no longer on PIPP.	Columbia Gas - Warm Choice: Weatherization measures include insulation, air sealing and high-efficiency furnaces. Homeowners and renters whose income is 150% or less of federal poverty guidelines are eligible. Dominion East Ohio - Housewarming Program Provides weatherization assistance to eligible customers. Duke Energy: Income-qualified customers receive a furnace or heat pump clean and tune, energy-efficient light bulbs, energy-saving tips and if needed, a hot water heater wrap, weather stripping and pipe wrap. Depending on the condition of your home and its energy usage, other services may include duct sealing, wa and attic insulation and other air leakage sealing measures.	Columbia Gas - Heatshare: Funded by shareholder and customer donations, this fund helps low-income customers who have nowhere else to turn for energy assistance. The Salvation Army administers the fuel-funds program. Dominion East Ohio - EnergyShare Sponsored by Dominion East Ohio, the EnergyShare program is designed to help needy individuals and families pay any type of winter heating bill--natural gas, wood, oil, kerosene or electricity. Contact your local Salvation Army office to apply. Duke Energy - HeatShare: Designed to assist those in need with heating bills during the winter season. Eligibility is based upon need and doesn't necessarily follow government assistance guidelines. An individual must be subject to disconnection of service in order to qualify. Eligible customers may apply for a one-time annual assistance beginning mid-January through May or until funds are depleted. For additional information or to apply for assistance, contact the Salvation Army after the program begins in mid-January. Ohio Edison - Project Reach: Provides once-a-year financial assistance to disabled, unemployed or low-income customers who migh The Illuminating Company - Community Outreach Opportunity Program (CO-OP) Provides once-a-year financial assistance to disable Toledo Edison - Neighbors Helping Neighbors Provides once-a-year financial assistance to disabled, unemployed or low-income cus Consolidated Electric Cooperative - The People Fund A community service program that responds to the needs of the community tha Firelands Electric - Operation Round Up Customer donations assist individuals and organizations. Guernsey-Muskingum Electric Cooperative - Operation Helping Others Customer donations assist individuals and community organiz Logan County Cooperative - Operation Round Up Health and rescue organizations, food banks, educational projects, child care prog Lorain-Medina Rural Electric Cooperative - Operation RoundUp Customer donations can assist individuals with special needs, health North Central Electric Cooperative - Operation Round Up Customer donations can assist individuals with special needs, health and r
Oklahoma	$ 15,728,845	110% Federal Poverty Level	Heating: $57 min, $220 max; Cooling: $120 max for 1 person household, $180 max for 2+ person household	Heating: 87,520; Cooling: 32,632	10.3%	Max. benefit: $2,826	60% State Median Income	1,150				Seasonal: Oklahoma prohibits disconnection of natural gas or electric service if the National Weather Service forecasts any of the following temperatures for the day of disconnection: 32°F or below during the daytime; 20°F or below during the nighttime; 103°F or above during the day. In addition, the Oklahoma Corporate Commission has the authority to order a temporary ban on all disconnections during periods of extremely severe weather, or in circumstances where disconnection would be dangerous to the life or health of the customer. Health: The state requires utilities to delay for up to 30 days disconnection of residential service if a licensed medical doctor or osteopath certifies that disconnection of service would precipitate a life-threatening condition because the customer or a permanent household member is dependent on electrically operated equipment that is needed to sustain the person's life. A medical certificate may be renewed once, for a total of 60 days. The customer is required to pay the bill in full or negotiate a deferred-payment arrangement for the balance during the period of delay. Income/Deferred Payments: The state delays disconnection of natural gas and e		Oklahoma Gas & Electric: LIHEAP customers pay the regular residential rate for the first 600 kWhs used and then receive a credit of $0.67 per kWh from November through April. Oklahoma Natural Gas: LIHEAP customers receive a reduced gas bill which averages $5.03 a month during the winter months (October through April) and $4.26 during the summer months (May through September).		America Electric Power - Light A Life: Customer and AEP donations are distributed through the Salvation Army. Canadian Valley Electric Cooperative - Operation Roundup Member donations provide funds to assist individuals and organizations with medical care, food, clothing, housing, educational assistance and other needed services that are not being met by other agencies. Indian Electric Cooperative - Operation Round Up Member donations assist organizations and individuals with a variety of worthy causes throughout the service area. Northeast Oklahoma Electric Cooperative - Operation Round-Up In 1998, Northeast Electric launched the Operation Round-Up program. Collected money is placed into a benevolence fund and overseen by the Northeast Electric Cooperative Trust Foundation, Inc. The funds that accumulate in the foundation will be distributed to individuals and organizations which prove to be worthy of the funds. Proper application for funds must be made, and the governing board of trustees (separate from the cooperative's board) will determine who will receive assistance. Oklahoma Electric Cooperative - Operation Round-Up Member donations provide assistance to individuals and organizations experie Oklahoma Gas & Electric - Lend-A-Hand Customer contributions are forwarded to the Salvation Army which distributes the money to Oklahoma Natural Gas - Share the Warmth Customer donations assist persons over 62 and persons with disabilities in addition to ot Public Service Company of Oklahoma (PSO) - LIGHT A LIFE Energy Fund Contributions come from customers of PSO who also pay
Oregon	$ 24,591,465	60% State Median Income	Heating: $150 min, $276 avg, $320 max	Heating: 58,000	11.1%	Avg. benefit: $3,855	60% State Median Income	2,551	Oregon Energy Assistance Program: Oregon's restructuring legislation requires its two investor-owned electric companies to collect $10 million per year, beginning in 2000, for low-income electric bill payment assistance. The funds are administered by the state LIHEAP office and must be expended in the service area of the electric company from which the funds are collected. Income eligibility for the electric assistance funds is the same as for LIHEAP, 60% of state median income. Emerald PUD (2 programs) - [1] ERAP Emerald's Rate Assistance Program assists low-income seniors (60 years or older) and disabled households with bills. Letters are sent from Lane County to those who qualify[2] AFP (Arrearage Forgiveness Program): A one-year case management program that helps with energy and money management. If a customer stays current with electric bills for one year, the arrearage they entered the program with is forgiven.	Utility restructuring legislation established a 3% Public Purpose Charge (PPC) to be collected from the state's two investor-owned electric companies. About 13% of the PPC, about $7.8 million, is earmarked for low-income weatherization, distributed through the state weatherization agency network. Collection of these funds began March 1, 2002. Low Income Weatherization Program: Oregon Housing and Community Services performs energy audits to determine appropriate services. State devotes 13% of the total collected public purpose charge to fund low-income weatherization services. Households with incomes at or below 60% of the state median income are eligible for assistance. Households served in 2005: more than 1,600		Seasonal: Oregon delays disconnection of residential natural gas or electric service for nonpayment for up to six months if a medical professional certifies that the disconnection would be dangerous to the health of the customer or other permanent household member. If the medical professional labels the householder's illness as "chronic," the utility is required to delay disconnection for up to 12 months. Customers submitting a medical certificate are required to enter into a written deferred-payment arrangement. Deferred Payments: Oregon prohibits natural gas and electric utilities from disconnecting residential service if the customer enters into a written deferred-payment plan, which at a minimum offers a choice between a level payment plan and a down payment and equal pay arrearage plan.		Avista Utilities - LIRAP: A low-income rate assistance program funded by Avista customers. Eugene Water & Electric Board (3 programs) - [1] Universal Service Plan This program provides low-income seniors and disabled customers with weatherization services and bill co-payments. At the successful end of the program, EWEB will forgive any arrearage on the customer's bill. The Human Services Commission administers the program. [2] Low-income customers may also be eligible for the Deposit Guarantor program, which provides assistance for half of a qualifying customer's account deposit (not to exceed $300). Anyone who is accepted into the Deposit Guarantor program must also participate in EWEB's Customer Care Plus. [3] Military assistance: This is a special, limited-duration program for military personnel who are called to active duty and serve overseas in Iraq, Afghanistan or in support of those military actions. Families of eligible military personnel may receive up to $300 in bill-payment assistance per 12-month period. City of Ashland (3 programs) - [1] Low Income Senior Discount Utility discounts a Columbia River PUD - The Special Waiver Program Waives the $7 monthly cust NW Natural - Gas Assistance Program (GAP): GAP collects funds from NW Nat Salem Electric - Winter Heating Assistance Program Available to members who	Energy Smart: Oregon HEAT provides low-income households with energy conservation education and hardware to reduce energy use through its Energy Smart program. This pilot project takes a holistic approach to meeting household needs by lowering energy bills to make them more affordable. Energy Smart will also identify the best ways to promote and encourage energy conservation education. Pacific Power - Community Energy Project, Inc. of Multnomah County Provides senior and disabled citizens with energy education and energy-efficient measures. Portland General Electric - Community Energy Project Helps low-income senior citizens and persons with disabilities conserve energy in their homes. PGE provided seed money to help launch the Community Energy Project years ago and continues to financially support CEP through grants that are used to purchase weatherizing materials. CEP also holds weatherization workshops and provides attendees with water-conserving showerheads and compact fluorescen light bulbs. Columbia River PUD - Low-Income Weatherization Assistance Program Provide Emerald PUD - REACH: Provides weatherization services for low-income house Eugene Water & Electric Board - Customer Care Plus Designed to help income-	Oregon HEAT: A statewide fund designed to prevent disconnection of utility service during inclement weather by providing bill payment assistance to low income households in emergency situations. Oregon HEAT works with social service and other agencies across the state to screen requests for assistance from customers of Pacific Power, PGE and West Oregon Electric Cooperative. Oregon HEAT also has a recovered oil program and helps households pay for all fuels such as propane, gas and wood. Avista Utilities - Project Share: A community program supported by shareholders, customers and employees. The funds are forwarded to community action agencies, which work with each family. Grants are available to those in need without regard to their heating source. Blachly-Lane County Coop Electric Assn - Blachly-Lane Energy Share The program is designed to offer assistance to members who do not not qualify for other types of relief. The Salvation Army administers the program. Canby Utility Board - Energy Assistance Program Customers with a 24 hour disconnect notice may apply for funds once per year for Cascade Natural Gas - Winter Help: Funded through donations from Natural Gas customers. The funds are targeted for low-income Central Electric Coop - Project Helping Hand Funded by CEC members to help needy customers with their electric bills when they en Central Lincoln People's Utility District - SOS Program Contributions from customers are turned over to local service agencies for dist City of Ashland - Heat and Roundup One-time help for customers, based on need and availability of funds. Maximum bill credit of $1 City of Cascade Locks - Energy Assistance Program: Applicants are eligible for one payment per heating season of $150. Eligibility is City of Gresham - Utility Customer Assistance Fund A program to assist water, sewer, and stormwater customers with bill payments. Clatskanie People's Utility District - Share the Warmth Fund The fund is run by the P.U.D. through the Community Action Team which Columbia River Public Utility District - GLOW (Give Light, Offer Warmth) The fund is used to provide families with emergency bill pay Consumers Power Inc. - Operation Round Up© Provides funding to address special needs for individuals or families as well as speci
Pennsylvania	$ 134,810,209	150% Federal Poverty Level	Heating: $100 min, $245 avg, $1200 max	Heating: 294,000	17.2%	Avg. benefit: $2,826	150% Federal Poverty Level	12,406			Customer Assistance Referral and Evaluation Program (CARES) The CARES program helps customers with special needs. CARES may help you find ways to pay your utility bill. For example, special needs are customers who are experiencing family emergencies, divorce, unemployment, or medical emergencies. The goal is to provide support and direction to help customers pay their utility bills.	Seasonal: From December 1 to April 15, Pennsylvania requires utilities to seek permission from the PUC before disconnecting residential natural gas or electric service for nonpayment. In practice, the Pennsylvania PUC does not grant permission for disconnection of service for nonpayment during the winter months. Health: Pennsylvania requires utilities to delay for up to 30 days disconnection of residential service if a medical professional certifies in writing that the customer or a permanent household resident is seriously ill or affected by a medical condition that would be aggravated by a lack of utility service. The medical certificate can be renewed two more times, the customer is required to negotiate a deferred payment arrangement during the period of delay. Deferred Payments: Utilities are required to offer residential customers in danger of service disconnection an opportunity to enter into a deferred payment agreement, and they are required to maintain service to the customer if the customer agrees to the arrangement.		Pennsylvania's major gas and electric utilities are required to provide Customer Assistance Programs (CAPs), which generally provide a percentage of bill plan or a percentage of income payment plan, wherein low-income customers' utility payments are based upon their incomes and/or utility bills. Some programs include utility arrearage forgiveness; others provide flat rate discounts or bill credits. Under electric and gas restructuring legislation all electric and gas utilities are required to offer universal service programs, to include CAPs, and to continue pre-restructuring low-income programs. Hardship Funds: Utility company hardship funds provide cash assistance to utility customers to help them pay their utility bills. Hardship funds provide assistance grants to customers who "fall through the cracks" of other financial assistance programs, or to those who still have a critical need for assistance after the other resources have been exhausted. The funds make payments directly to companies on behalf of eligible customers.	Mandated by a 1987 PUC order, the Low-Income Usage Reduction Program (LIURP) was renewed in 1992 thru 1996, and continued under universal service provisions of electric and gas utility restructuring legislation. The state's 15 major gas and electric utilities participate in LIURP with a pre-restructuring funding level of about 2/10 of 1% of each utility's total revenues. LIURP includes an education component that addresses energy savings, regular bill payment behavior and provides application assistance. Allegheny Power (3 programs) - [1] CAP Reduced monthly payment based on a percentage of the household's income. If customer is faithful to the plan, arrearages are reduced. [2] Waived late payment charges Eligibility: 150%, or below, federal poverty guidelines[3] LIURP: Emphasis on baseload electric measures; lighting; heating system, water heater, and refrigerator replacement. Columbia Gas of Penn (3 programs) - [1] CAP Affordable payment plans for customers with low incomes and long-term bill payment problems. Eligibility: 150%, or below, federal poverty guidelines[2] Warm Choice: A free weatherizati Dominion Peoples (3 programs) - [1] CAP Based on income and family size, CA Duquesne Light (3 programs) - [1] CAP: Payment reduction based on percentage	$1 Energy Fund The $1 Energy Fund, Inc. was founded in 1983 in Western Pennsylvania by a coalition of concerned community, religious, and business leaders, and has grown to become the fourth largest fuel fund in the country, both in clients served and dollars granted. The fund partners with utility companies across Pennsylvania. Each company matches every donation dollar for dollar and makes a separate donation towards administrative expenses. Philadelphia Utility Emergency Services Fund The Philadelphia Utility Emergency Services Fund is one of the largest fuel funds in the country, providing over $2 million annually in energy crisis assistance benefits in recent years. It was created by utility companies, public officials, business leaders, and community organizations in response to increased terminations of gas, electric, and water service coupled with inadequate LIHEAP benefits. Philadelphia's three major utilities (gas, electric and water) provide a dollar-for-dollar match to every dollar raised and contribute to the fund's operating costs. Philadelphia residents have thirteen sites to choose from to get help with their utility bills. Equitable Gas - Hardship Fund Supplemental payments for repair/replacement of defective heating equipment or gas lines. National Fuel Gas - Neighbor For Neighbor Heat Fund The fund is supported by customer, employee and shareholder donations that PECO - Matching Energy Assistance Fund (MEAF) MEAF is an energy assistance program that enables PECO Energy to assist low- PPL - Operation Help: Funds may be used to pay any type of home heating bill (electric, natural gas, oil or coal). Funding comes from PPL Gas Utilities - Operation SHARE: Provides emergency financial aid to pay heating bills for families with financial hardships. Oper Pennsylvania Power Company - Reach Hardship Fund The fund is supported by employee and customer contributions that are match UGI Penn Natural Gas - Project Outreach: Resources include shareholder, employee and customer contributions and special fund ra
Rhode Island	$ 13,628,926	60% State Median Income	Heating: $400 min, $500 avg, $650 max	Heating: 29,000	13.0%	Max. benefit: $3,200	60% State Median Income	895		Appliance Management Program (Refrigerator Replacement Program) Special services are available to low income National Grid customers to help lower energy bills with our Energy Efficiency and Conservation Programs. The goal of the program is to provide a comprehensive review of the customer's electric bill, existing appliances and electric use patterns. The program provides client education, ideas and information you can use to help make saving energy easier and more cost effective. The program targets low income households that are customers of the National Grid Company. Heating System Replacement Assist's owner occupied low and moderate income households with major repairs and/or the replacement of their boiler/furnace. This program is designed to increase the boiler/furnaces efficiency and to insure the health and safety of the household occupants. Clients must be income eligible and pre-approved by their local Community Acti Program (CAP Agency) in order to be applicable for this program.	RISEO Emergency Fuel Program This state program is separate from LIHEAP and offers emergency assistance to households that are experiencing an energy-related crisis. An application may be submitted if a household has not received heating assistance and the fuel tank is empty or near empty or if they are in danger of losing utility service.	Seasonal/Low-Income: From November 1 to March 31, Rhode Island prohibits disconnection of residential natural gas or electric service to households containing seriously ill or disabled persons, residents 65 years of age or older, unemployed persons, or persons eligible for or receiving LIHEAP. Utilities are also prohibited from disconnecting residential service to non-protected customers if the customer owes the utility $500 or less for utility service that is the primary heat source or $200 or more for service that is not the primary source of heat. Health: The state requires utilities to delay for up to 21 days disconnection of residential service for nonpayment if a licensed physician certifies that any resident of the customer's household is seriously ill. If the duration of the illness exceeds 21 days, the customer may request a review to determine if the initial delay will be extended, and, if so, for how long. Deferred Payments: The state requires utilities to offer residential payment plans to customers who are in danger of having their service disconnected for nonpayment. Protected status customers are required (at a minimum) to pay on		Rhode Island Utility Discounts As a condition of deregulation of the electric industry in Rhode Island, the state requires utilities to provide low-income rate discounts to eligible customers, and preserves all existing low-income programs that were offered by the utilities before deregulation. Narragansett Electric: Provides a discount rate for low-income households amounting to about $9 per month.	Narragansett Electric - Appliance Management Program An Energy manager from your local Community Action agency will provide an appliance analysis which indicates how much each appliance costs to operate and how much you might save. You may qualify for other items including: ENERGY STAR® refrigerators, ENERGY STAR® lighting, water saving measures and insulation and air sealing measures.	Good Neighbor Energy Fund A statewide cooperative effort between gas and electric companies and The Salvation Army. The Good Neighbor Energy Fund is available to any Rhode Islander who, because of temporary financial difficulty, cannot meet a month's energy expense and has not qualified for or received other energy assistance funds. The maximum Fund grant is $300, the total of which can be distributed to more than one utility. The Fund grant is given only one time per family per heating season and a recipient must exceed LIHEAP income guidelines. UniBank Fuel Assistance Fund Funds may be available to families who do not qualify under traditional income guidelines, to families who cannot afford the standard 100-gallon minimum delivery amount, or to those families who may have already reached their annual limit for fuel oil benefits. For more information on applying for a grant, contact the Worcester Community Action Council, Inc.
South Carolina	$ 13,589,900	150% Federal Poverty Level	Heating or Cooling: $150 min, $370 max	Heating: 18,030; Cooling: 3,984	5.3%	Max. benefit: $5,652	150% Federal Poverty Level	1,149				Seasonal/Health: Between December 1 and March 31, South Carolina requires natural gas and electric utilities to delay disconnection of residential natural gas or electric service for up to 31 days, if a medical professional certifies that disconnection of service would adversely affect the health of the customer or a permanent household member. A medical certificate can be renewed up to three times during the winter protection period. Deferred Payments: Before disconnecting residential service for nonpayment, natural gas and electric utilities are required to provide customers with an opportunity to enter into a deferred-payment arrangement. The utility is prohibited from disconnecting service whenever a customer accepts and adheres to such an arrangement.				Progress Energy - Energy Neighbor Fund The project receives support from employees, customers, churches and civic organizations. Employee and customer campaigns help raise funds for the Energy Neighbor Fund each fall, and the Progress Energy Foundation provides $250,000 in matching funds. Duke Power (3 programs) - [1] Share the Warmth A heating bill assistance program funded by Duke Power customers and Duke Energy shareholders. The Duke Energy Foundation matches individual contributions, dollar-for-dollar up to $50, for a maximum corporate contribution of $500,000 annually. The funds may be used for the payment of heating costs, regardless of energy source. [2] Cooling Assistance Program: Funded by Duke Power and the Duke Energy Foundation, an annual contribution of $250,000 is spread among the counties within their service area. A specific agency (or agencies) is selected in each county to distribute the funds and to determine the criteria for family eligibility[3] Fan-Heat Relief Program: The Duke Energy Foundation contributes $40,000 annually for the purchase of fans for senior citizens. Administered by the N.C. Department of Human Resources/Division of Aging. Piedmont Natural Gas - Share the Warmth Piedmont matches contributions from customers and employees. Funds are used to help South Carolina Electric & Gas Co. - Project Share Through contributions to Project Share, SCE&G employees and customers provid Aiken Electric Cooperative - Operation Round Up® AEC members help provide food, shelter, clothing, healthcare and other services
South Dakota	$ 12,807,748	160% Federal Poverty Level	Heating: $235 min, $865 max	Heating: 18,000	19.3%	Max. benefit: $2,744	160% Federal Poverty Level	619				Seasonal: From November 1 to March 31, South Dakota requires utilities to give an additional 30 days' notice before disconnecting service to residential customers. Health: South Dakota requires utilities to delay for up to 30 days disconnection of residential service for nonpayment if a physician or other public heath or social service official certifies in writing that such an action would adversely affect the health of the customer or another permanent resident of the household. Deferred Payment: The state requires natural gas and electric utilities to offer residential customers the opportunity to avoid disconnection of service by agreeing and adhering to a deferred-payment agreement.				MidAmerican Energy - I Care The I CARE program helps your local community action agencies provide financial assistance for heating bills and home weatherization. MidAmerican Energy contributes funds based on customer contributions and pays all administrative costs. Sioux Valley Southwestern Electric - Operation Round Up Voluntary contributions from participating cooperative customers. The Operation Round Up funds are kept in a trust fund and are dispersed as directed by the Operation Round Up board. Individuals are eligible to receive up to $2,500/year. West River Electric Association, Inc. - Operation Round Up Operation Round Up donations are placed in trust and administered by a independent Board of Directors. The funds will be available to help any charitable projects for organizations, groups, families, or individuals within the service territory of West River Electric.
Tennessee	$ 27,583,705	125% Federal Poverty Level	Heating and Cooling: $150 min, $750 max	Heating: 74,267	4.8%	Max. benefit: $2,744	125% Federal Poverty Level	2,672				Seasonal: Tennessee prohibits disconnection of residential electric or natural gas service for nonpayment when the National Weather Service forecasts the temperature at that location to be 32°F or below for that calendar day. Health: The state requires natural gas and electric utilities to delay for up to 30 days disconnection of residential service if a physician or public health or social service official certifies in writing that such an action would adversely affect the health of the customer or that of a permanent household member. During these 30 days, the utility is required to refer the customer to social service agencies fo investigation, confirmation of need, and guarantee of payment. Medical certificates may be renewed three times, each for an additional 30-day period. Deferred Payments: The state requires utilities to offer customers an opportunity to avoid disconnection by entering into a deferred-payment arrangement. Such an arrangement requires the customer to pay the current bill as due, and to pay the overdue balance in installments over six months.		Memphis Light Gas and Water - On Track A payment program designed to help customers with limited incomes to manage debt and pay off their bills over a period of time. The program focuses on education, financial management and social services. To qualify for the program customers must have a steady, but limited, income and owe more than $600 to MLGW. Participants may receive Extended Payment Plans for up to three years; minor home repairs for homeowners; and deposit credited back to the account after completion of program.	Memphis Light Gas and Water - EnergySmart Memphis A year-long energy education and home improvement initiative designed to help Memphians save money on their energy costs. Customers will receive in-depth energy conservation training and eligible customers will have weatherization improvements made to their home.	Appalachian Power - Neighbor-to-Neighbor Program The eligibility of recipients is determined and funds are distributed by the Upper East Tennessee Human Development Agency. Athens Utility Board - Warm Neighbors Program Working with Coordinated Charities of McMinn County, AUB provides a way to help those in need to maintain their service without interruption. Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. Cumberland Electric Member Corporation - Project Help A voluntary program that allows members to pay an additional amount on their electric bill each month to help pay utility bills of those who really need the assistance. Duck River Electric Member Corporation - Project HELP. Customer donations will help defray the cost of energy for elderly and handicapped members. Holston Electric Cooperative - Project Help Member donations help those less fortunate to stay warm in the winter. Jackson Energy Authority - Project Help Area Relief Ministries distributes funds from Project Help to people in need all year long. Mo Knoxville Utilities Board - Project Help Project Help is an emergency heating-assistance program that buys electricity, natural gas, ke Memphis Light Gas and Water - Plus-1 A program administered by the Metropolitan Inter-Faith Association (MIFA) to pay utility servi Meriwether Lewis Electric Cooperative - Project Help This voluntary program allows members to contribute each month to help those Middle Tennessee Electric Membership Corporation - Project Help Member donations help defray emergency energy costs for elderly Mountain Electric Cooperative - Operation Pocket Change Customer donations provide funds for qualified community projects, progr Morristown Utility Systems - Project Help Customer donations provide funds for those who need help paying their utility bill. The fund
Texas	$ 45,044,208	125% Federal Poverty Level	Heating: $704 avg, $1200 max; Cooling: $739 avg, $1200 max	Heating: 7,192; Cooling: 15,082	2.7%	Max. benefit: $2,826	125% Federal Poverty Level	4,800	Lite-Up Texas: Effective July through October 2007, low-income customers in areas with retail electric choice (Houston, Dallas, and areas of South and West Texas) are eligible for a summer discount. Households currently receiving Food Stamps or Medicaid will automatically be included in the program if the information on file with the Health and Human Services Commission matches information on file with the household's Retail Electric Provider. Those with total household income of less than 125% of federal poverty guidelines may apply by calling 1-800- 241-7011. (The discount will also be available June through October of 2008 and June through September of 2009.)	The electric competition law created a System Benefit Fund part of which is used to help finance energy efficiency programs. The Texas Department of Housing and Community Affairs (TDHCA) will administer energy efficiency programs in coordination with existing weatherization programs. Utilities will develop standard-offer programs to install energy efficiency measures that may include: compact fluorescent lightbulb lease-purchase programs, refrigerator and air-conditioner lease-purchase programs, and water-flow restrictors (low-flow shower heads and faucet aerators) provided free of charge. Independent service providers will deliver these services to customers. TDHCA operates partnership programs with: Central Power & Light, El Paso Electric, Entergy, HLP / Reliant, Southwest Public Service, Southwestern Electric Power, Texas Utilities Electric, Texas-New Mexico Power and West Texas Utilities.		Seasonal: Texas prohibits utilities from disconnecting residential natural gas or electric service for nonpayment when the temperature was 32 degrees or below on the previous day and is forecasted by the National Weather Service to be 32°F or below during the next 24 hours. Utilities are also prohibited from dosconnecting service if a heat advisory has been in effect for any of the two preceding days. In these cases the utility must defer collection full payment until after the weather emergency is over and work with customers to establish a pay schedule for deferred bills. Health: Texas requires utilities to delay for up to 63 days disconnection of residential service if a licensed physician certifies that such an action would adversely affect the health of the customer or a household resident. The customer is also required to enter into a deferred-payment agreement with the utility by the stated date of disconnection. Low-Income: Texas prohibits electric utilities from disconnecting residential service for nonpayment if the utility receives notification that an energy assistance provider intends to forward payment on the client's behalf.		Austin Energy - Low-Income Discount The $6 service charge is waived for customers with persons living in the household who receive SSI, City of Austin Medical Assistance Program (MAP) or Aged, Blind and Disabled Medicaid. Eligible customers can also receive a 50% reduction on their residential City of Austin Drainage fee. Central Power & Light - Lite-Up Texas Effective July through October 2007, low-income customers are eligible for a summer discount. Households currently receiving Food Stamps or Medicaid will automatically be included in the program. Those with total household income of less than 125% of federal poverty guidelines may apply by calling 1-800- 241-7011. (The discount will also be available June through October of 2008 and June through September of 2009.) El Paso Electric - Low Income Rider Eligible customers will not be billed the Residential Service Customer Charge. Eligibility: Food Stamp recipient First Choice Power - Lite-Up Texas: Effective July through October 2007, low-income customers are eligible for a summer discount. Households currently receiving Food Stamps or Medicaid will automatically be included in the program Reliant - Lite-Up Texas: Effective July through October 2007, low-income custon TXU Energy - Lite-Up Texas: Effective July through October 2007, low-income c	Austin Energy - Energy Home Improvements Provides attic insulation, sealing and/or repairing of ductwork,caulking of plumbing penetrations, door weatherstripping, solar screen installation for income-qualified customers.	Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. Austin Energy - Customer Assistance Program The City of Austin sponsors the program to assist eligible customers who are having difficulty paying their utility bill. The program is funded through voluntary contributions from utility customers. Several local social serv agencies screen applications and determine eligibility. Entergy Texas - The Power to Care Funds provide short-term utility bill assistance to low-income elderly or disabled. Entergy - Beat The Heat During May, thousands of fans are distributed to customers by numerous partner agencies such as Total Community Action, Salvation Army and various Councils on Aging and with the assistance of employee volunteers. Central Texas Electric Cooperative, Inc. - Operation Round Up Member donations provide funds for individuals with special needs, health and rescue organizations, food banks, educational projects, and child care programs. Applications from individuals, organizati Comanche Electric Cooperative - Operation Round Up Donated funds may be used for funds may be used for community service pro Denton Municipal - P-L-U-S One Program Customer contributions are forwarded to Interfaith Ministries, which disburses the funds to Public Service of San Antonio (2 programs) - [1] Residential Energy Assistance Partnership (REAP) A non-profit foundation that helps New Braunfels Utilities - Utility Bill Assistance Program Designed to aid persons in NBU's service area to pay for their electric, water a Reliant Energy - CARE: A community-based program designed to support Reliant Energy customers who are having difficulty making Sam Houston Electric Cooperative - Helping Hands Program Sam Houston Electric Cooperative's non-profit Helping Hands Program San Bernard Electric Cooperative - Operation Roundup Member donations assist members in need with utility bill payments. These a South Plains Electric Cooperative - Operation Round-Up Member donations are spent locally for: individuals - including victims of fire
Utah	$ 14,744,631	125% Federal Poverty Level	Heating: $50 min, $295 avg, $550 max	Heating: 31,000	10.9%	Max. benefit: $3,100	125% Federal Poverty Level	1,562				Seasonal: Between November 15 and March 15, Utah prohibits disconnection of residential utility service if the customer has a written notice from the utility statin that a deferred-payment arrangement could not be agreed upon; that the customer has applied for HEAT assistance and Red Cross utility assistance; and further, that any of the following criteria apply to the customer either in the month of application or the month before: Has a household income at or below 125% of the federal poverty guideline; Experiences a medical emergency; Becomes unemployed or experiences a 50% or greater drop in income; Winter moratorium participants must pay at least 5% of household income (10% for electric heating) toward utility costs. Health: Utah requires utilities to delay for up to 30 days disconnection of residential service for nonpayment whenever a physician certifies that such an action would adversely affect the health of the customer or that of a household member. Deferred Payments: Utilities are required to offer customers the opportunity to avoid disconnection by agreeing and adhering to a deferred-payment arrangem		Rocky Mountain Power (PacifiCorp) - Home Electric Lifeline Program (HELP) The program is funded through a surcharge on all electric customer bills, averaging about $0.12 per month, and operates in coordination with Utah's LIHEAP. Applications will be available for non-LIHEAP households at community-based organizations when LIHEAP is not operating. Participating customers will receive an $8 per month credit on their bills.	Rocky Mountain Power (PacifiCorp): Energy education, electrical usage evaluation, appliance testing, audit and the installation of cost-effective measures.	Questar Gas - REACH - Residential Energy Assistance through Community Help REACH is funded through contributions from local residents through tax-deductible donations included with their utility payments and donations from utility employees and stockholders. The American Red Cross administers the program and distributes the funds. Eligibility: low income and age 65 or older or disabled. Catholic Community Services - Crisis Funds for Salt Lake County Applications are available April to January for help once per heating season. Eligibility: must be approved for HEAT program first, based on 125 percent of poverty guidelines. Provo City Power (2 programs) - [1] HELP. Voluntary donations are sent each month to Community Action Services to distribute. [2] The city also has a program to help military families with 50 percent of the utility bill written off for up to six months. Rocky Mountain Power (PacifiCorp) - Lend a Hand An organization formed to help families and seniors in need pay their winter heating bills. Customer donations are matched dollar-for dollar by Utah Power,funds are administered by the American Red Cross.
Vermont	$ 11,746,617	Heating: 125% Federal Poverty Level; Crisis: 150% Federal Poverty Level	Heating: $50 min, $1364 avg, $1565 max	Heating: 21,022	15.9%	Max. benefit: $3,000	150% Federal Poverty Level	1,373	Emergency/General Assistance provides emergency help to meet basic needs, including fuel and utilities. Eligible are persons with little or no income and resources who are unable to work or who have employment barriers. Also persons who have experienced a crisis such as a fire, flood, death in the family or eviction may be eligible. Individuals must apply in person at PATH district offices when they have an emergency. Seasonal Fuel Assistance: Fuel Assistance can help to pay part of your home heating bills. To determine your eligibility, we will consider both your household's income and resources. You can have a monthly net income up to 125% of federal poverty levels, and you can have up to $5,000 in resources.	The Weatherization Trust Fund established in 1990, is funded by a 0.5 percent gross receipts tax on regulated utilities and all fuels except wood. The trust fund has raised about $3 million annually to supplement the Vermont Weatherization Assistance Program.	Emergency/General Assistance provides emergency help to meet basic needs, including fuel and utilities. Eligible are persons with little or no income and resources who are unable to work or who have employment barriers. Also persons who have experienced a crisis such as a fire, flood, death in the family or eviction may be eligible. Individuals must apply in person at PATH district offices when they have an emergency. Crisis Fuel Assistance helps Vermonters who experience a crisis during the winter months. Your household income can be up to 150% of the federal poverty level. However, in addition to being income eligible, you must show that you are experiencing a crisis.The income level used to determine eligibility for Crisis Fuel Assistance is higher than that of the Seasonal Fuel Assistance Program.	Seasonal: Vermont prohibits disconnection of residential natural gas or electric services for nonpayment from November 1 through March 31 if the National Weather Service forecasts temperatures to be at or below 10°F (32°F for households with members age 62 or older) for a 48-hour period beginning on the morning of the date of disconnection. Health: Vermont requires utilities to delay for up to 30 days disconnection of residential service for nonpayment if a physician certifies in writing that the customer or a household member would suffer a health hazard in the event of service disconnection. A physician's certificate may be renewed twice within a calendar year. Deferred Payments: The state requires utilities to offer residential customers the opportunity to avoid disconnection by agreeing and adhering to a deferred-payment arrangement. The state prohibits utilities from disconnecting service to customers who accept and complete such an arrangement.		Green Mountain Power - Energy Support 10% discount for customers whose annual household income is at or below 200 percent of the federal poverty level.	A unique "energy efficiency utility" called Efficiency Vermont was created by the Vermont legislature and Vermont Public Service Board to provide energy efficiency services to low-income and other customers. The Low-Income Single Family Program provides electric efficiency improvements to eligible customers of Vermont's electric utilities (except in Burlington) who are actively enrolled in the federal Weatherization Assistance Program. Measures include energy efficiency lighting, refrigerator replacement, and water heater efficiency measures. Also provides energy efficiency measures to owners, managers and developers of multi-family housing units. Green Mountain Power Offers free weatherization service to low-income households through local weatherization agencies. Qualified technicians come to your home and inspect the heating system, make any necessary repairs, insulate, and seal air leaks.	WARMTH: The WARMTH Support Program uses funds donated by concerned Vermonters to help low-income families pay their energy costs. All contributions go directly to fuel suppliers; administrative costs are funded by participating fuel dealers and utilities. WARMTH funds are available when a household has exhausted its supply of fuel or faces disconnection of utility services. Funds are only available when an individual has not been able to find sufficient help through other channels. Central Vermont Public Service - The Shareheat Fund The Fund helps less fortunate customers pay their winter energy bills. Recipients must have exhausted other fuel assistance funds before receiving help from Shareheat. Donations are distributed to community action agencies operating within the CVPS service territory, which in turn, provide the funds on a case-by-case basis to those in need.

	FEDERAL							
	LIHEAP FY2008 Funding	LIHEAP Income Eligibility Level	LIHEAP FY2007 Benefit	LIHEAP Households Served (FY2006/07 Estimate)	% of Eligible HHs ≤150% FPL Receiving Energy Assistance (2006)	Weatherization Assistance Program (WAP) Benefit (FY2006)	WAP Eligibility (FY2006)	WAP Households Served (FY2006)
Virginia	$ 38,943,773	130% Federal Poverty Level	Heating: $142 min, $265 avg, $441 max; Cooling: $100 max	Heating: 110,590; Cooling: 38,685	8.2%	Max. benefit: $2,826	130% Federal Poverty Level	1,036
Washington	$ 40,449,571	125% Federal Poverty Level	Heating: $25 min, $750 max	Heating: 64,000	10.2%	Avg. benefit: $4,150	125% Federal Poverty Level	4,371
West Virginia	$ 17,934,982	130% Federal Poverty Level	Heating: $80 min, $210 avg, $500 max	Heating: 79,493	14.4%	Max. benefit: $4,000	150% Federal Poverty Level	1,330
Wisconsin	$ 70,537,552	150% Federal Poverty Level	Heating: $10 min, $260 avg, $1200 max	Heating: 145,844	14.8%		150% Federal Poverty Level	8,032
Wyoming	$ 5,903,426	60% State Median Income	Heating: $65 min, $1120 max	Heating: 12,077	11.1%	Avg. benefit: $2,744	60% State Median Income	700

	STATE / LOCAL				
	Low Income Rate Assistance	Low Income Energy Efficiency	Low Income Emergency Assistance	Seasonal, Health, and Income Related Disconnection Policies	Low Income - Other
Virginia				Virginia does not have state-mandated disconnection policies related to temperature, health, or income.	All participating vendors for the LIHEAP Fuel and Crisis Assistance components agree to waive charging the State Sales Tax on all fuel deliveries. Eligible households receive the amount that would be paid to the State for sales tax in the total amount of fuel delivered.
Washington		State general funds go to "Energy Matchmaker" program and are matched by local, utility and other funds. The funds were used to weatherize 1,291 low-income homes in FY 2002. Measures included attic, wall and floor insulation, weatherstripping and furnace modifications.		Seasonal/Low-Income: Between November 1 and March 31, Washington prohibits disconnection of residential natural gas and electric service for nonpayment if customers are able to fulfill the following requirements: Declare an inability to pay a bill and/or required deposit; Have household income at or below 125% of the federal poverty guideline; Apply for energy assistance and low-income weatherization assistance; Pay at least 7% of monthly income each month to utility in addition to one-twelfth of past due amounts accrued from date of application. Health: Washington requires utilities to delay for up to 60 days disconnection of residential service for nonpayment if the utility receives written or verbal notice that a medical emergency exists at the customer's residence. The utility may require the customer to submit written certification from a physician stating that disconnection would aggravate an existing medical condition of a resident of the customer's household. Deferred Payments: The state also prohibits disconnection of residential service for nonpayment if the customer agrees and adheres to a deferred payment arra	
West Virginia				Seasonal: Between December 1 and February 28, West Virginia prohibits disconnection of residential natural gas or electric service for nonpayment because such action is interpreted as being dangerous to the health and safety of the customer's household. Health: West Virginia requires utilities to delay for up to 30 days disconnection of residential service for nonpayment if a licensed physician certifies that such an action would be dangerous to the health of the customer or a household membe Certificates may be renewed every 30 days for the duration of the illness unless the physician can state that the condition is permanent. Deferred Payments: Utilities are required to offer residential customers in danger of having their service disconnected for nonpayment the opportunity to enter into a deferred-payment agreement. If the customer agrees and adheres t such an agreement, service cannot be disconnected.	
Wisconsin	A Public Benefits Fund (PBF) created in 1999 under energy reliability legislation funds low-income energy programs, along with other conservation and renewables programs. Funding for the low-income energy portion of the PBF varies each year and comes from three sources: prior utility (gas and electric) low-income expenditures (about $21 million per year), a new access fee or customer charge on all electric bills, and the current year's federal LIHEAP and weatherization allocations. Funding is split between energy assistance and energy efficiency. The new funding allows the LIHEAP program to pay a non-heating electric benefit, averaging about $92 for FY 2003, along with the regular LIHEAP heating benefit. Low-income programs formerly operated by utilities will transition to the LIHEAP grantee by January 2003. The State of Wisconsin under Wis. Stat. Chapter 49 directs General Assistance funds to households without assets or means of support to provide a minimum of life's necessities including the cost of home heating. General assistance is provided only as a last resort to eligible households. State and local sales taxes are suspended for LIHEAP eligible households for the Housing Cost Reduction Initiative Utility Payment Program: State funds are distri	Focus On Energy is a public-private partnership offering energy information and services to energy utility customers throughout Wisconsin. The Targeted Home Performance with ENERGY STAR® program assists Wisconsin residents in making energy efficiency improvements to their homes. Wisconsin residents wh receive their electricity from a participating utility, and who meet the income requirements, are eligible to participate. Depending on results from a home energy assessment, energy efficiency measures may include insulation, sealing air leaks, heating system update or energy saving devices.		Seasonal: From November 1 to April 15, Wisconsin prohibits disconnection of natural gas or electric service to households with incomes at or below 250% of poverty. Utilities are allowed to disconnect services to other residential customers during this period only if the household does not include members wi because of age, developmental or mental disabilities, illness, or infancy, would have their health or safety endangered by such an action. Health: The state requires utilities to delay for up to 21 days disconnection of residential service for nonpayment if a licensed Wisconsin physician certifies that such an action would aggravate an existing medical condition of the customer or a household member. During the delay the utility must work with the customer to make a reasonable payment arrangement. The delay may be extended to facilitate completion of such an agreement. Deferred Payments: Wisconsin requires utilities to offer residential customers the opportunity to avoid disconnection by negotiating a deferred payment arrangement. Disconnections are prohibited when customers agree and adhere	
Wyoming	Senior Tax Rebate: Provides a tax rebate in the form of a check made out to the client for up to $500 or $600 depending on program guidelines. You must be 65 years of age or older, or over age 18 and 100% disabled, and a Wyoming resident for one full year at the time of application. An applicant must be income qualified.			Seasonal: Wyoming prohibits disconnection of natural gas or electric service to residential customers for nonpayment between November 1 and April 30 if any of the following apply: The customer can establish a documented inability to pay for services, and; The customer has exhausted government assistance, or The customer is actively in the process of seeking government assistance, or The customer is able to pay for service only by installments. Health: The state requires utilities to delay for up to 22 days disconnection of residential service for nonpayment if a physician certifies that a member of the household is handicapped or seriously ill. If the physician certifies that a member of the household is on life support, the utility must allow 30 days for the customer to enter into a deferred payment arrangement. Deferred Payments: The state requires utilities to offer deferred payment arrangements to residential customers in danger of losing service because of nonpayment. Disconnections are prohibited when customers agree and adhere to such arrangements.	

	UTILITY	
	Low Income Rate Assistance	Low Income Energy Efficiency
Virginia	Four major utilities in Virginia waive security deposits for LIHEAP eligible customers: Appalachian Power; Dominion Virginia Power; Virginia Natural Gas; Washington Gas	Dominion Virginia Power - Fan Care Provides free fans to elderly Virginians within the Dominion Virginia Power service area who are age 60 or older and meet income guidelines defined by the Area Agencies on Aging. Fan Care is a public-private partnership administered by the Department for the Aging; Dominion Virginia Power is the primary sponsor. Virginia Natural Gas: Home Weatherization Assistance is available to eligible households. A professional crew will visit a home and determine what weatherization measures best suit the house. Some of the services they might recommend and perform are: caulking and weatherstripping; additional insulation for ceilings and walls; repair of leaky duct systems and repair/replacement of heating/cooling systems.
Washington	All of the utilities and Public Utility Districts listed below provide rate discounts for low-income, seniors or disabled customers. Discounts range from 5% to 40% of a customer's utility bill. Tacoma Public Utilities: Special discount rates for all City of Tacoma utilities are available to qualified, low-income customers who are, 62 years or older or disabled: 25% discount from Tacoma Power, Tacoma Water and Sewer Utility; 35% discount from Solid Waste Utility; and; discount on Click! Network cable television services. Seattle City Light (3 programs) - [1] Utility Assistance for Seniors and Disabled - Rate 26: The Utility Credit Program provides substantial savings for low-income seniors and people with disabilities who receive City of Seattle utility services. Savings are on combined utilities (water-wastewater-solid waste) and City Light electric bills. [2] Special Utility Rate 27: This program provides a reduced utility rate for income eligible households. Qualified applicants receive a 50% discount on their Seattle City Light Bill and possibly on their Combined Utility Bill. [3] Emerge AVISTA Utilities (2 programs) - [1] Senior Energy Outreach Provides assistance Benton Co. PUD (2 programs) - [1] Low-Income Senior Discount Customers 62 y Chelan County PUD - Rate Discount: Low-income senior citizens and disabled c City of Port Angeles (2 programs) - [1] Senior Energy Credit Program Seniors 62	Avista Utilities - Refrigerator Replacement Program Pacific Power - Yakima Valley Opportunities Industrialization Center Provides needs assessment and case management counseling services, including the development of a family budget and energy education. Participants receive do-it-yourself maintenance and upkeep on appliances. Referrals to programs such as food banks, medical services and weatherization programs are available, in addition to employment and training opportunities. Seattle Office of Housing - HomeWise Weatherization: Weatherization grants can insulate single family homes with low-income households as well as apartment buildings that qualify. After an energy analysis of your home is performed, an energy conservation package, which includes insulation, venting, weatherstripping, and more, will be installed. Tacoma Power - Residential weatherization Financial assistance is available to help weatherize the homes of customers who meet certain income guidelines. Chelan County PUD: Through a combination of state and District funds, the Chelan-Douglas Community Action Council weatherizes low-income homes. Cowlitz County Public Utility District - Residential Weatherization Conservation C Douglas PUD: Douglas PUD has participated in the Washington State Departme Grays Harbor PUD: The low-income weatherization program provides grants to
West Virginia	All gas and electric utilities offer a reduced rate of 20% from December - April Eligible customers must receive either SSI, WV WORKS, or Food Stamps AND be 60 years of age or older. Customers must be a recipient of one of these programs during November, December, January, February, and March to get the discount for that month. The discount is a Commission Order, dated March 10, 1984. Allegheny Power Dominion Hope: Twenty percent discount on gas bill December through April for SSI or Food Stamp recipients who are 60 years of age or older.	
Wisconsin	The PBF legislation also requires municipal electric utilities and electric cooperatives to collect fees annually per customer, with half of the funds collected going to low-income programs Many municipals and co-ops retain the fees for their own internal low-income/weatherization programs. If approved for LIHEAP, customers of some municipals and co-ops can receive bill credits, home energy efficiency measures or refrigerator replacements. Cedarburg Light & Water Utility - Energy Assistance Program Jefferson Utilities (3 programs) - [1] Energy Assistance Program; [2] Refrigerator Replacement Program; [3] Home weatherization Program Manitowoc Public Utilities (2 programs) - [1] Commitment to Community Program A customer receiving a state heating assistance benefit is automatically eligible for this program. An electric assistance benefit will appear as a credit ona future bill. [2] Weatherization Assistance: Based on a home energy analysis, eligible customers may receive insulation, air sealing, heating system repair or replacement, water saving measures and compact fluorescent lighting. Menasha Utilities (3 programs) - [1] Energy Assistance Program Establish incom New Holstein Utilities - Energy Assistance Program: Establish income eligibility th	The PBF legislation also requires municipal electric utilities and electric cooperatives to collect fees annually per customer, with half of the funds collected going to low-income programs Many municipals and co-ops retain the fees for their own internal low-income/weatherization programs. If approved for LIHEAP, customers of some municipals and co-ops can receive bill credits, home energy efficiency measures or refrigerator replacements. Cedarburg Light & Water Utility - Energy Assistance Program Jefferson Utilities (3 programs) - [1] Energy Assistance Program; [2] Refrigerator Replacement Program; [3] Home weatherization Program Manitowoc Public Utilities (2 programs) - [1] Commitment to Community Program A customer receiving a state heating assistance benefit is automatically eligible for this program. An electric assistance benefit will appear as a credit ona future bill. [2] Weatherization Assistance: Based on a home energy analysis, eligible customers may receive insulation, air sealing, heating system repair or replacement, water saving measures and compact fluorescent lighting. Menasha Utilities (3 programs) - [1] Energy Assistance Program Establish incom New Holstein Utilities - Energy Assistance Program: Establish income eligibility th
Wyoming	Pacific Power: Pacific Power partners with Wyoming Energy Council, Inc. to replace inefficient appliances such as refrigerators and air-conditioners with Energy Star-certified models. Cheyenne Light Fuel and Power Will provide a $30 benefit per household to LIEAP eligible customers.	Pacific Power: Pacific Power partners with Wyoming Energy Council, Inc. to replace inefficient appliances such as refrigerators and air-conditioners with Energy Star-certified models. Cheyenne Light Fuel and Power Will provide a $30 benefit per household to LIEAP eligible customers.

	CHARITABLE
	Emergency Charitable Assistance Programs
Virginia	American Electric Power - Neighbor-to-Neighbor AEP matches customer contributions up to $37,500. Customers must supply a disconnect notice to the Department of Social Services. The program begins in January and continues until funds are exhausted or March 31, whichever comes first. Atmos Energy - Sharing the Warmth Customer donations combine with company donations to help people pay their gas bills. All donations go directly to local people in need that meet criteria established by each individual program's guidelines. Columbia Gas of Virginia - Heatshare: Funded by customer and company contributions and administered by the Salvation Army, Heatshare is an emergency fund to help households with energy bills. Dominion Virginia Power - EnergyShare Created in 1983 to help low-income households pay any type of heating bill. EnergyShare is supported by donations from utility stockholders, employees and customers, businesses, churches, and civic groups. In addition, matching funds and administrative costs are paid by the utility. Beginning in the summer of 2008, eligible seniors (age 60 and older) can apply for cooling assistance of up to $200 per season. Northern Virginia Electric Cooperative - Operation Round UP Customer and utility donations provide assistance with their heating bills. Virginia Natural Gas - EnergyShare Beginning in January, help with energy payments may be available if all alternatives available thr Washington Gas - Washington Area Fuel Fund: Provides heating assistance payments for low-income households in the Washington
Washington	Avista - Project Share: A community program supported by shareholders, customers and employees. The funds are forwarded to community action agencies, which work with each family. Grants are available to those in need without regard to their heating source. Pacific Power - Project HELP: Pacific Power matches customer donations dollar-for-dollar to Project HELP. Tacoma Power - Family Need An assistance program for low-income households with children under 18 in the household. Tacoma Power customers who qualify are eligible for a once-a-year assistance payment applied to their account. Households who heat with electricity receive a $150 payment. Seattle City Light - Project SHARE A program for customers who have received an urgent notice and have taken advantage of all the other assistance programs. Funded by customer donations, it will pay up to $500 of your electric bill. Customers must be referred by Seattle City Light Customer Service. Cascade Natural Gas - Winter Help: This fund is administered by Washington's Community Action Agencies. CNG will match each dollar donated by customers and employees. Chelan PUD - Helping Hands The Chelan/Douglas Community Action selects qualified families for the program, 509-662-6156. City of Port Angeles - Pass the Buck Funded by voluntary donations and assists low-income city residents with their utility bills. The C City of Richland - Helping Hands Customer donations to help other customers in a time of need. A one-time payment of up to $100 h Clallam County PUD - Neighborly Assistance Program Customer donations provide funds to qualified low-income residential custome Clark County PUD - Operation Warm Heart Fuel assistance program that helps pay home heating bills for the elderly, the ill... for all v Cowlitz County PUD - Warm Neighbor Program Customer donations assist qualified low-income families with their electric bills. Elect Elmhurst Mutual Power & Light - Shine a Light Customer donations provide emergency financial assistance to qualified, low-income c Ferry County PUD - Project Share: A heating assistance program.
West Virginia	Dominion Hope - Heat Fund Helps low-income customers pay their gas bills. The Salvation Army administers this fund which is made up of donations from employees and customers and then matched dollar for dollar by Dominion Hope.
Wisconsin	Keep Wisconsin Warm Fund (KWWF): KWWF is a voluntary, community-based program designed to fill the need for energy assistance to low income people. The program began as a pilot in Dane County, and is now expanding statewide. The KWWF is funded by businesses (including utilities) and individual contributions. Eligibility requirements are the same as for WHEAP -- 150% of poverty and below. Alliant Energy - Hometown Care Energy Fund Customer donations help low-income families heat their homes during the winter. Funds are administered through regional community action programs. Madison Gas and Electric - Energy Fund Donations come from MGE customers, shareholders and employees assists families and individuals who find it impossible to cover basic living costs. The difficulties may come from medical bills, job loss or other emergencies. They may live on a fixed income or work for low hourly rates. A nonprofit agency distributes the money. Adams-Columbia Electric Cooperative - Operation Round Up Member donations provide funds for emergency assistance following natural disasters, youth programs, civic projects and more. Individuals and community service organizations are encouraged to apply. Chippewa Valley Electric Cooperative - Operation Round Up® - Chippewa Valley Community Fund, Inc. Member contributions are use Menasha Utilities - Project Share Fund Menasha customers who are willing to assist local families facing emergency situations with t Oakdale Electric Cooperative - Operation Round-Up® Funded by cooperative members, the Oakdale Electric Trust Fund provides as River Falls Municipal Utilities - Helping Hand The utility matches the payment a customer makes on an account to help bring the acco Scenic Rivers Energy Cooperative - Operation Round-Up Members contributions are distributed to individuals and organizations to a
Wyoming	Energy Share of Wyoming Energy assistance for those who do not qualify for LIEAP and are experiencing a situation such as a medical or family crisis, which makes it difficult to pay their energy bills. Funded by utility companies, customers, local businesses and private donation. Applications are taken through the local Salvation Army or the Sundance, Gillette or Sheridan Powder River Energy offices. Lower Valley Energy - The Operation Roundup The program, which is administered by an independent board of directors, provides assistance with energy, fuel, housing and food expenses for local families and individuals needing assistance.

		Customer Eligibility Requirements						Type of Assistance Offered (Reduced / Waived)							How is Reduction / Waiver Determined?				Funding Sources					UTILITY
	Utility Rate Assistance Program Offered	% of Federal Poverty Level	% of Median State Income	Participation in SSI / AFDC	Annual Income Level	Senior / Disabled Persons	Medical Condition / Need	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Customer Usage	Other	Ratepayers (Voluntary / Mandatory)	State Tax / Surcharge	Federal / State Grants	Charitable Contributions	Other	Low Income Rate Assistance
Alabama	Yes			X				Waived							X				X					Alabama Power Co: Customers who are verified as Supplemental Security Income (SSI) or Aid for Families with Dependent Children (AFDC) recipients will not be billed a monthly service charge of approximately $8.91. Alagasco: Customers who receive Supplemental Security Income (SSI) or Aid for Families with Dependent Children (AFDC) will not be billed a monthly customer charge of about $8. Mobile Gas: Customers who receive Supplemental Security Income (SSI payments or Aid to Dependent Children) and who qualify, can have the customer charge of approximately $8 waived from their monthly gas bill.
Alaska	No																							
Arizona	Yes	X				X	X		Reduced					Reduced Monthly Bill	X	X	X		X					Arizona Public Service (2 programs) - [1] Energy Support Program: Offers a discount up to 40% off the cost of electricity for customers who meet certain income guidelines. The income guidelines are based on 150% of the federal poverty guidelines and change every July 1st. The discount varies depending on how much electricity is used each month. [2] Medical Care Equipment Program: Offers a discount up to 40% off the cost of electricity for customers who meet certain income guidelines. The income guidelines are based on 150% of the federal poverty guidelines and change every July 1st. The discount varies depending on how much electricity is used each month. Applicants must also provide a letter from a doctor showing a need of life sustaining medical equipment. Unisource Energy Services - C.A.R.E.S.: Customers whose income does not exceed 150% of the federal poverty level may be eligible for a deduction of up to $8 off their monthly electric bills and up to $15 off their natural gas bills, depending upon usage. CARES rates also apply to the Low-Income Medical Life Support Program for customers who are medically life-support dependent and w Salt River Project (2 programs) - [1] Economy Price Plan: Customers with limited
Arkansas	Yes				X	X				Waived		Waived		Waived Sales Tax for first 500 kWhs	X		Waived Sales Tax for first 500 kWhs							Entergy Arkansas: Sales tax exemption on the first 500 kWh used each month for customers with an annual household income of less than $12,000. Empire District Electric Company - Empire's Action to Support the Elderly (EASE): Provides late fee and security deposit waivers for seniors age 60 and older and disabled customers.
California	Yes	X		X	X	X	X	Reduced / Waived	Reduced					Reduced Monthly Bill	X	X	X		X					REFER TO DETAILED STATE SUMMARY Through the California Alternate Rates for Energy (CARE) program eligible customers receive a 20% discount on electric and natural gas bills. Eligibility: total household income is at or below 200% of federal poverty level. The CARE income guidelines, effective June 1, 2007, are as follows: Household size 1 or 2 = Income $29,300; Household size 3 = Income $34,400; Household size 4 = Income $41,500; Household size 5 = Income $48,600; Add $7,100 for each additional household member
Colorado	No																							
Connecticut	Yes	X		X	X	X	X						Reduced / Waived					Arrearage Amount	X					A systems benefits charge (SBC) imposed on customers of the state's two investor-owned utilities – Connecticut Light & Power and United Illuminating – pays for some low-income programs. SBC-funded arrearage, uncollectibles, and hardship programs for both utilities amounted to about $7.2 million in 2004. All gas public service companies are required by statute to operate an arrearage forgiveness program for gas heating customers. Arrearages are forgiven if customer makes regular payments. Eligibility criteria include: arrears of $100 or more that are 60+ days overdue, income of less than 200% FPG, and have had at least $25 paid toward bill by LIHEAP (or other assistance program). Electric utilities have voluntary arrearage forgiveness as part of budget programs. Connecticut Light and Power (3 programs) - [1] NUSTART: Customers can reduce or eliminate their past-due balance if they pay an agreed-upon budgeted amount on time, each month. Eligibility: arrears of $100 or more that are 60+ days overdue, income of less than 200% FPG, and have had at least $25 paid toward bill by LIHEAP (or other assistance program). [2] Matching Payment Plan Connecticut Natural Gas - Matching Payment Plan Customers who qualify for ma Southern Connecticut Company - Matching Payment Plar: Customers who qualif
Delaware	No																							
District of Colu	Yes	X	X						Reduced					Reduction on first 400 kWhs		X	Reduction on first 400 kWhs		X					The Public Service Commission requires Potomac Electric Power Company (PEPCO), and Washington Gas to offer discount rates to low-income residential customers. PEPCO - Residential Aid Discount on first 400 kWhs of electricity used each month. This translates into a savings of up to $5 per month or $60 a year. Washington Gas Company - Residential Essential Service (RES): This program offers discount gas rates, based on household size and income level, during the winter months from November through April. There are three classifications: Class C may receive a total discount up to $142.02, Class B up to $151.03 and Class A up to $189.08.
Florida	No																							
Georgia	Yes				X	X		Waived							X				X					Since 1989, the Public Utility Commission (PUC) has mandated that major gas and electric utilities waive their monthly service charge for customers over age 65, who own their homes, and earn less than $12,000 per year. Atlanta Gas Light: Senior citizens who are 65 years of age or older and have a total annual combined household income of $12,000 or less are eligible for a $10.50 monthly discount on their base charge. To apply contact your gas marketer. Georgia Natural Gas: Customers who are 65 years of age or older with an annual combined gross income per household of $12,000 or less are eligible for a $14.00 monthly discount on their base charge. Georgia Power: The monthly base charge ($10.50 for gas and $14.00 for electric) is waived for customers who are at least 65 years old and the total household income is not more than $12,000 annually. SCANA Energy: Customers who are 65 years of age or older with an annual combined gross income per household of $12,000 or less are eligible for a $14.00 monthly discount on their AGL base charge. Carroll Electric Membership Corporation - Senior Citizen Discount: Members ove
Hawaii	No																							

		Customer Eligibility Requirements						Type of Assistance Offered (Reduced / Waived)							How is Reduction / Waiver Determined?				Funding Sources					UTILITY
	Utility Rate Assistance Program Offered	% of Federal Poverty Level	% of Median State Income	Participation in SSI / AFDC	Annual Income Level	Senior / Disabled Persons	Medical Condition / Need	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Customer Usage	Other	Ratepayers (Voluntary / Mandatory)	State Tax / Surcharge	Federal / State Grants	Charitable Contributions	Other	Low Income Rate Assistance
Idaho	Yes																		X					Avista Utilities - LIRAP: A low-income rate assistance program funded by Avista customers.
Illinois	Yes	X			X	X	X							One-time credit up to $240 for higher-than-average rate increase of 30% or more	X	X		One-time credit up to $240 for higher-than-average rate increase of 30% or more						ComEd - Rate Relief Program (3 programs) - [1] Summer Assistance Program: A one-time $30 credit for Low Income Home Energy Assistance Program participants with household incomes up to 200% of the poverty level, or $40,000 for a family of four. [2] Residential Rate Relief Program: A one-time credit of up to $240 for customers who experienced a higher-than-average rate increase of 30% or more. This program is for households with incomes up to 200% of the poverty level, or $40,000 for a family of four. [3] Residential Hardship Fund: Variable grants of up to $1,000 to offset rate increases for people with special circumstances and hardships. Customers with household incomes up to 400% of the poverty level, or $80,000 for a family of four, may be eligible, if they identify a special hardship issue such as medical expenses, military service, seniors requiring in-home care or grandparents raising minor grandchildren, or a person in the home with a disability. Verification of hardship will be required. Springfield City Water Light & Power - Senior Citizen Discount Rate: A 10% disc
Indiana	Yes	X			X					Waived			Reduced		X	X		Arrearage Amount	X			Utility donation		Northern Indiana Public Service Co. (NIPSCO) - Winter Warmth: LIHEAP eligible customers or customers with a financial hardship can receive up to $400 that can be applied to both the payment of delinquent utility bills and natural gas deposits. Additionally, NIPSCO will limit natural gas deposit payments for LIHEAP eligible customers to $150 and $300 for other non-LIHEAP eligible customers determined to have a financial hardship.
Iowa	No																							
Kansas	No																							
Kentucky	Yes	X			X								Reduced	Reduced Monthly Bill	X			Arrearage Amount	X					Louisville Gas & Electric - Home Energy Assistance: Provides a year-round fixed credit that varies by month and is based on the household's income, size and utility bills for the previous 12 months, an adjustment for monthly normal heating degree days, and any significant changes in utility pricing. The credit can be applied to arrearages. Customers with household income at or below 110% of federal poverty guidelines must have a minimum monthly household income of $100 and household utility arrearages under $700 and to participate. Kentucky Utilites - Home Energy Assistance: Eligible customers will receive a fixed amount of $294 per year in seven monthly installments of $42 that are applied to the current bill. The credit will be applied to bills during peak heating and cooling months and cannot be used to reduce arrearages. Customers must use electric heat and have household income at or below 110% of federal poverty guideline to participate.
Louisiana	Yes				X	X		Waived							X									Entergy Gulf States Utilities, Inc. - Senior Discount Program: Waiver of $6.00 monthly customer charge for customers who are 65 or older and have an annual income less than $10,000. Entergy New Orleans - Elderly and Handicapped Emergency Assistance Fund Entergy provides funding for the program, that is administered by the New Orleans Council on Aging and Total Community Action, to address the needs of the disadvantaged through direct energy assistance.
Maine	Yes	X		X	X	X	X						Reduced	Reduced Monthly Bill	X		X						% of utilities annual revenues	Low-Income Assistance Program (LIAP): Maine's transmission and distribution utilities are required to create or maintain a LIAP to make electric bills more affordable for LIHEAP-eligible customers. The Maine State Housing Authority administers, implements and coordinates the statewide plan and the individual LIAPs in conjunction with its delivery of LIHEAP. The fund amounts to approximately $5.7 million yearly. Bangor Hydro Electric (2 programs) - [1] LIHEAP-eligible customers may qualify for a rate discount. Depending on income, the percentage of the discount will vary based on kWh usage. [2] Emergency Assistance Program: Limited to AFDC families, or families with children under the age of 18, who may be eligible for AFDC. One of the program's functions is to assist families in paying past due energy-related costs in order to avoid being shut-off. Central Maine Power - Electricity Lifeline Program: Offers qualified low-income customers a credit on their electric bill. This credit is based on household income and estimated electricity usage and is applied to your bill for the same amount ea Maine Public Service Co. - PowerPact: LIHEAP-eligible customers who keep cur
Maryland	Yes				X					Waived	Waived			Reduced Monthly Bill; Waived Application Fee	X	X								The largest utility, Baltimore Gas and Electric, and many smaller utilities offer deposit, reconnect fee and application fee waivers to qualifying customers. Baltimore Gas and Electric - Customer Assistance Maintenance Program (CAMP): Under the CAMP, customers who participate in the Universal Service Protection Program can qualify to earn monthly bill credits ranging from $7 to $12. The amount of credit is based upon income. Allegheny Power - Energy assistance plans Washington Gas Light Company - Residential Essential Service (RES): MEAP-eligible residents who use natural gas for home heating and who are current on their utility bills may be eligible to receive discounts on a portion of their Washington Gas bills during the winter heating season. The discount could be worth up to $135.

		Customer Eligibility Requirements						Type of Assistance Offered (Reduced / Waived)							How is Reduction / Waiver Determined?				Funding Sources					UTILITY
	Utility Rate Assistance Program Offered	% of Federal Poverty Level	% of Median State Income	Participation in SSI / AFDC	Annual Income Level	Senior / Disabled Persons	Medical Condition / Need	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Customer Usage	Other	Ratepayers (Voluntary / Mandatory)	State Tax / Surcharge	Federal / State Grants	Charitable Contributions	Other	Low Income Rate Assistance
Massachusett	Yes	X		X	X	X		Reduced	Reduced				Reduced / Waived	Reduced Monthly Bill	X	X			X		X			Over a dozen gas, electric and combination IOUs offer utility rate discounts totaling nearly $40 million per year and ranging from 20% to 42% off the low-income customer bill. These discounts were negotiated during the past two decades and were required to continue under Massachusetts' restructuring legislation. Households earning less than 175% of Federal Poverty Guidelines, or receiving one of several means tested programs, including LIHEAP, Food Stamps, TANF and SSI are eligible. NSTAR - R2 Discount Rate: Discount rate for customers who receive certain government means-tested benefits or qualify for fuel assistance. KeySpan Energy Delivery (Boston, Essex and Colonial Gas Companies): You may receive a discount if you are a low-income residential customer and participate in the following public assistance programs: SSI, AFDC, Medicaid, E.A.E.D.C., Food Stamps, Refugee Resettlement, Fuel Assistance or Massachusetts Veterans Service Benefits (G.L.C. 115). KeySpan Energy Delivery - On Track: On Track works with 350 low-income 1-2 family heating customers, who are receiving public assistance, to help them reso Massachusetts Electric: Monthly discount for customers with income at or below Nantucket Electric: Monthly discount for customers with income at or below 175% Western Massachusetts Electric - Residential Discount Rate: Discount rate for in
Michigan	Yes	X		X		X				Waived			Waived			X			X					Arrearage forgiveness and deposit and fee waivers are provided by utilities that participate in the state's automated positive billing system and other payment plans. Under positive billing, a participating household must pay a percentage of its monthly assistance grant to its utility. Winter Protection Plan: This plan protects senior and low-income customers of Commission-regulated natural gas and electric companies, rural electric cooperatives and alternative electric suppliers from electric or natural gas service shut-off and high utility payments between December 1 and March 31. Persons qualify for the plan if they meet any of the following criteria: are age 65 or older, or receive Michigan Family Independence Agency cash assistance, or receive Food Stamps or Medicaid, or have a household income at or below 200% of poverty level. Winter Protection allows eligible low income customers to make monthly payments of at least 7% of their estimated annual bill, along with a portion of any past-due amount, December through March, and avoid shut-off during that time even if their bills are higher. Eligible senior citizens participating in Winter Protec
Minnesota	Yes				X									Reduction on first 300 kWhs			Reduction on first 300 kWhs of 50%		X					Xcel Energy: As a result of legislation passed in 1994, Minnesota requires that electric companies serving over 200,000 residential customers provide a 50% discount for low-income customers on the first 300 kilowatt hours consumed each month. The provision applies only to the state's largest utility, Xcel Energy. The average benefit is $108 per household.
Mississippi	Yes			X		X		Waived							X									Mississippi Power: Monthly base charge is waived ($0.46 per day) for eligible low-income and elderly customers receiving SSI or AFDC.
Missouri	Yes					X			Reduced	Waived		Waived			X	X								Empire District Electric Company - Empire's Action to Support the Elderly (EASE): Provides late fee and deposit waivers for elderly (age 60 and older) and handicapped customers. Independence Power & Light Department - Independence Rate Assistance Program (IRAP): Qualified elderly, 60 years or older, or disabled customers pay 50% of the electric charges on their bill. Contact the Community Services League.
Montana	Yes	X						Reduced						Reduced Monthly Bill		X			X					NorthWestern Energy: Customers who qualify for LIEAP, automatically receive a discount on their NorthWestern Energy electric and natural gas bills. Flathead Electric Cooperative: Eligible members receive a credit equal to half the basic charge on their bill each month. In most cases this is an $8.00 per month credit. Residential members must qualify as low-income according to the guidelines set by LIEAP (150% of federal poverty level). Members qualifying with LIEAP after October 1 will automatically be eligible. All recipients must reapply each year. Hill County Electric - Universal Services Benefit Program: A $100 benefit is available through July 31for customers who qualify. After July 31, customers may reapply for any remaining funds available. Lincoln Electric Co-op: Low-income seniors over 65, and permanently disabled members may be eligible for a 10% reduction in their energy bill. Members who qualify for Supplemental Disability or Social Security Disability income are qualified if they meet the income test. Missoula Electric Cooperative: Customers who receive LIEAP may be eligible for Park Electric Co-op - Senior Income Eligible Discount: Available to members of t
Nebraska	No																							
Nevada	Yes				X	X				Waived	Waived		Waived		X			Arrearage Amount						Lincoln County Power District: Company funds provide deposit and reconnection fee waivers to low-income households who could not secure other assistance. Sierra Pacific Power Company: Company funds provide arrearage forgiveness, deposit waivers and, in special cases, reconnection fee waivers to low-income households with a senior 62 years or older or a disabled member. Valley Electric Association - Lighthouse Assistance Program: The program is designed to provide assistance to members who, through income limitations or other unusual circumstances find themselves in a situation where they are having difficulty paying their electric bill. The program is administered by the County social service agencies in the counties serviced by the Association.

	Utility Rate Assistance Program Offered	Customer Eligibility Requirements: % of Federal Poverty Level	% of Median State Income	Participation in SSI / AFDC	Annual Income Level	Senior / Disabled Persons	Medical Condition / Need	Type of Assistance Offered (Reduced / Waived): Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	How is Reduction / Waiver Determined?: Fixed Amount	% of Total Bill	Customer Usage	Other	Funding Sources: Ratepayers (Voluntary / Mandatory)	State Tax / Surcharge	Federal / State Grants	Charitable Contributions	Other	UTILITY: Low Income Rate Assistance
New Hampshi	Yes	X		X	X								Waived	Reduced Monthly Bill		X		Arrearage Amount	X					Beginning October 1, 2002, the tiered-discount program (TDP), a modified percentage of income plan, will serve about 23,800 households. The tiers are structured to provide qualified low-income households with monthly energy bill payments equal to, on average, 4% of income for general use customers and 6% for electric heat users. Arrearages existing on or before August 31, 2002 are eligible for retirement. Granite State Electric - Electric Assistance Program: Qualified customers receive discounts on electric service. KeySpan Energy Delivery: Qualifying heating customers will receive a 50% discount on the gas delivery portion of their gas bill starting November 1, 2005. To qualify, a household must receive or be qualified to receive benefits from one of a number of programs such as LIHEAP, SSI, Food Stamps, WIC, TANF and others. New Hampshire Electric Co-operative - Electric Assistance Program: Provides qualifying members with a discount on their monthly electric bill. The discount is based on the household gross income and the type of space heating used in the home. Northern Utilities: Qualifying heating customers will receive a 50% discount on th
New Jersey	Yes	X		X	X	X							X	Reduced Monthly Bill	X	X		Arrearage Amount	X					Lifeline Assistance Program: Funded from the New Jersey general fund, Lifeline provides a credit on electric or natural gas bills of $225 per year to disabled and senior homeowners and tenants. Beneficiaries of Medical Assistance to the Aged, Medical Assistance Only, or New Jersey Care, are sent Lifeline applications automatically every August. Supplemental Security Income recipients receive Lifeline automatically. Eligibility: must meet income eligibility guidelines and be 65 years or older or at least 18 years of age and receiving Social Security Disability benefits. Universal Service Fund: In June 2004, New Jersey's Board of Public Utilities (BPU) approved funding for the state's 2004-2005 Universal Service Fund (USF) low-income energy assistance program, which began in October 2003. The USF will fund a fixed credit percentage of income payment plan under which participants will be required to pay no more than six % of their annual income toward electric and gas bills. New Jersey electric and gas customers whose household income is equal to or less than 175% of the federal poverty lev
New Mexico	No																							
New York	Yes			X		X		Reduced		Waived	Waived		Waived		X	X		Arrearage Amount						New York's eight investor-owned utilities, and one municipal power authority, have low-income energy programs totaling about $20 million per year. The programs vary considerably by utility service territory and have varying eligibility guidelines. Most offer rate assistance and one or more other services such as arrearage forgiveness, weatherization, appliance repair and replacement and aggregation. Consolidated Edison (2 programs) - [1] Low-Income Plan: Retains the residential electric service customer charge at pre-1996 level for customers on Direct Vendor within Public Assistance. No fee for reconnection of service if turned off for non-payment for HEAP, Direct Vendor and SSI customers. Customers, age 62 or older, are exempt from paying a security deposit, unless service was turned off for nonpayment within the past six months. Recipients of Public Assistance or Supplemental Security Income are exempt from paying a security deposit. [2] Arrears Avoidance Program: Qualified low-income customers are eligible to receive a $200 grant toward their bills provided they maintain a deferred payment agreement with specified terms. Niagara Mohawk Power Corporation - AffordAbility Payment Plan: Enables qualif
North Carolin	No																							
North Dakota	No																							
Ohio	Yes	X			X								Reduced / Waived	Percentage of Income				Arrearage Amount; Percentage of Income	X					Dayton Power & Light (2 programs) - [1] percentage of Income Payment Plan Credit Program: Customers who have been on the PIPP program for one year and have more than 12 months PIPP arrears may be eligible for PIPP credits. The amount of credit is based on the total 12 months arrears. This credit is applied to the outstanding balance and not to the current installment.[2] Fresh Start: An arrearage-crediting program for customers no longer on PIPP.
Oklahoma	Yes								X								Reduced rate per kWh from Nov-April							Oklahoma Gas & Electric: LIHEAP customers pay the regular residential rate for the first 600 kWhs used and then receive a credit of $0.67 per kWh from November through April. Oklahoma Natural Gas: LIHEAP customers receive a reduced gas bill which averages $5.03 a month during the winter months (October through April) and $4.26 during the summer months (May through September).
Oregon	Yes		X		X	X		X		Reduced			Waived	Reduced Monthly Bill	X	X		Arrearage Amount	X			X		Avista Utilities - LIRAP: A low-income rate assistance program funded by Avista customers. Eugene Water & Electric Board (3 programs) - [1] Universal Service Plan: This program provides low-income seniors and disabled customers with weatherization services and bill co-payments. At the successful end of the program, EWEB will forgive any arrearage on the customer's bill. The Human Services Commission administers the program. [2] Low-income customers may also be eligible for the Deposit Guarantor program, which provides assistance for half of a qualifying customer's account deposit (not to exceed $300). Anyone who is accepted into the Deposit Guarantor program must also participate in EWEB's Customer Care Plus. [3] Military assistance: This is a special, limited-duration program for military personnel who are called to active duty and serve overseas in Iraq, Afghanistan or in support of those military actions. Families of eligible military personnel may receive up to $300 in bill-payment assistance per 12-month period. City of Ashland (3 programs) - [1] Low Income Senior Discount: Utility discounts Columbia River PUD - The Special Waiver Program: Waives the $7 monthly cus

		Customer Eligibility Requirements						Type of Assistance Offered (Reduced / Waived)							How is Reduction / Waiver Determined?				Funding Sources					UTILITY
	Utility Rate Assistance Program Offered	% of Federal Poverty Level	% of Median State Income	Participation in SSI / AFDC	Annual Income Level	Senior / Disabled Persons	Medical Condition / Need	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Customer Usage	Other	Ratepayers (Voluntary / Mandatory)	State Tax / Surcharge	Federal / State Grants	Charitable Contributions	Other	Low Income Rate Assistance
Pennsylvania	Yes	X			X								Waived	Reduced Monthly Bill	X	X		Arrearage Amount	X					Pennsylvania's major gas and electric utilities are required to provide Customer Assistance Programs (CAPs), which generally provide a percentage of bill plan or a percentage of income payment plan, wherein low-income customers' utility payments are based upon their incomes and/or utility bills. Some programs include utility arrearage forgiveness; others provide flat rate discounts or bill credits. Under electric and gas restructuring legislation all electric and gas utilities are required to offer universal service programs, to include CAPs, and to continue pre-restructuring low-income programs. Hardship Funds: Utility company hardship funds provide cash assistance to utility customers to help them pay their utility bills. Hardship funds provide assistance grants to customers who "fall through the cracks" of other financial assistance programs, or to those who still have a critical need for assistance after the other resources have been exhausted. The funds make payments directly to companies on behalf of eligible customers.
Rhode Island	Yes	X		X	X	X							Waived	Reduced Monthly Bill		X		Arrearage Amount	X					Narragansett Electric: Provides a discount rate for low-income households amounting to about $9 per month.
South Carolin	No																							
South Dakota	No																							
Tennessee	Yes				X					Waived					X									Memphis Light Gas and Water - On Track: A payment program designed to help customers with limited incomes to manage debt and pay off their bills over a period of time. The program focuses on education, financial management and social services. To qualify for the program customers must have a steady, but limited, income and owe more than $600 to MLGW. Participants may receive Extended Payment Plans for up to three years; minor home repairs for homeowners; and deposit credited back to the account after completion of program.
Texas	Yes	X		X		X		Waived						Reduced Drainage Fees by 50%	X			Reduced Drainage Fees by 50%						Austin Energy - Low-Income Discount: The $6 service charge is waived for customers with persons living in the household who receive SSI, City of Austin Medical Assistance Program (MAP) or Aged, Blind and Disabled Medicaid. Eligible customers can also receive a 50% reduction on their residential City of Austin Drainage fee. Central Power & Light - Lite-Up Texas: Effective July through October 2007, low-income customers are eligible for a summer discount. Households currently receiving Food Stamps or Medicaid will automatically be included in the program. Those with total household income of less than 125% of federal poverty guidelines may apply by calling 1-800- 241-7011. (The discount will also be available June through October of 2008 and June through September of 2009.) El Paso Electric - Low Income Rider: Eligible customers will not be billed the Residential Service Customer Charge. Eligibility: Food Stamp recipient First Choice Power - Lite-Up Texas: Effective July through October 2007, low-income customers are eligible for a summer discount. Households currently receiving Food Stamps or Medicaid will automatically be included in the program Reliant - Lite-Up Texas: Effective July through October 2007, low-income custom TXU Energy - Lite-Up Texas: Effective July through October 2007, low-income cu
Utah	Yes	X			X									Reduced Monthly Bill		X			X	X				Rocky Mountain Power (PacifiCorp) - Home Electric Lifeline Program (HELP): The program is funded through a surcharge on all electric customer bills, averaging about $0.12 per month, and operates in coordination with Utah's LIHEAP. Applications will be available for non-LIHEAP households at community-based organizations when LIHEAP is not operating. Participating customers will receive up to an $8 per month credit on their bills.
Vermont	Yes	X			X									Reduced Monthly Bill		X								Green Mountain Power: 10% discount for customers whose annual household income is at or below 200 percent of the federal poverty level.
Virginia	Yes									Waived					X									Four major utilities in Virginia waive security deposits for LIHEAP eligible customers: Appalachian Power; Dominion Virginia Power; Virginia Natural Gas; Washington Gas
Washington	Yes	X			X	X				Waived		Waived		Reduced Monthly Bill; Max Monthly Amount based on Income not Usage		X								All of the utilities and Public Utility Districts listed below provide rate discounts for low-income, seniors or disabled customers. Discounts range from 5% to 40% of a customer's utility bill. Tacoma Public Utilities: Special discount rates for all City of Tacoma utilities are available to qualified, low-income customers who are, 62 years or older or disabled: 25% discount from Tacoma Power, Tacoma Water and Sewer Utility; 35% discount from Solid Waste Utility; and; discount on Click! Network cable television services. Seattle City Light (3 programs) - [1] Utility Assistance for Seniors and Disabled - Rate 26: The Utility Credit Program provides substantial savings for low-income seniors and people with disabilities who receive City of Seattle utility services. Savings are on combined utilities (water-wastewater-solid waste) and City Light electric bills. [2] Special Utility Rate 27: This program provides a reduced utility rate for income eligible households. Qualified applicants receive a 50% discount on their Seattle City Light Bill and possibly on their Combined Utility Bill.[3] Emer AVISTA Utilities (2 programs) - [1] Senior Energy Outreach: Provides assistance Benton Co. PUD (2 programs) - [1] Low-Income Senior Discount: Customers 62
West Virginia	Yes			X		X								Reduced Monthly Bill from Dec-April		X							Credited against each utility's tax liability	All gas and electric utilities offer a reduced rate of 20% from December - April. Eligible customers must receive either SSI, WV WORKS, or Food Stamps AND be 60 years of age or older. Customers must be a recipient of one of these programs during November, December, January, February, and March to get the discount for that month. The discount is a Commission Order, dated March 10, 1984. Allegheny Power Dominion Hope: Twenty percent discount on gas bill December through April for SSI or Food Stamp recipients who are 60 years of age or older.

		Customer Eligibility Requirements						Type of Assistance Offered (Reduced / Waived)							How is Reduction / Waiver Determined?				Funding Sources					UTILITY
	Utility Rate Assistance Program Offered	% of Federal Poverty Level	% of Median State Income	Participation in SSI / AFDC	Annual Income Level	Senior / Disabled Persons	Medical Condition / Need	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Customer Usage	Other	Ratepayers (Voluntary / Mandatory)	State Tax / Surcharge	Federal / State Grants	Charitable Contributions	Other	Low Income Rate Assistance
Wisconsin	Yes	X												Reduced Monthly Bill	X	X			X				Utility funded	The PBF legislation also requires municipal electric utilities and electric cooperatives to collect fees annually per customer, with half of the funds collected going to low-income programs. Many municipals and co-ops retain the fees for their own internal low-income/weatherization programs. If approved for LIHEAP, customers of some municipals and co-ops can receive bill credits, home energy efficiency measures or refrigerator replacements. Cedarburg Light & Water Utility - Energy Assistance Program Jefferson Utilities (3 programs) - [1] Energy Assistance Program; [2] Refrigerator Replacement Program; [3] Home weatherization Program Manitowoc Public Utilities (2 programs) - [1] Commitment to Community Program: A customer receiving a state heating assistance benefit is automatically eligible for this program. An electric assistance benefit will appear as a credit ona future bill. [2] Weatherization Assistance: Based on a home energy analysis, eligible customers may receive insulation, air sealing, heating system repair or replacement, water saving measures and compact fluorescent lighting. Menasha Utilities (3 programs) - [1] Energy Assistance Program: Establish incom
Wyoming	Yes													Reduced Monthly Bill	X									Pacific Power: Pacific Power partners with Wyoming Energy Council, Inc. to replace inefficient appliances such as refrigerators and air-conditioners with Energy Star-certified models. Cheyenne Light Fuel and Power: Will provide a $30 benefit per household to LIEAP eligible customers.

38 **States with Rate Assistance Programs**
13 **States without Rate Assistance Programs**

Programs	Sponsor(s)	Program Type	Program Description
Winter Fuel Payments	UK Government	Rate Assistance	A Winter Fuel Payment is an annual payment to help people aged 60 and over with the costs of keeping warm this winter. If you are aged 60 to 79 and you are entitled to receive a Winter Fuel Payment, this year you will get either £125 or £250, depending on your circumstances in the qualifying week (15 to 21 September 2008). If you are aged 80 or over and you are entitled to a Winter Fuel Payment, this year you will either £200 or £400, depending on your circumstances in the qualifying week. You do not pay tax on Winter Fuel Payments.
Cold Weather Payments	UK Government, E.ON UK and Age Concern	Rate Assistance	Cold weather payments made to vulnerable households who are on certain benefits in periods of very cold weather in their area, to help pay for extra heating costs. To get a Cold Weather Payment the average temperature must be recorded as, or expected to be, 0°C or below for seven days in a row. These include a guaranteed cold weather payment of £10 for all gas customers, whilst those aged 60 or over receive an additional payment based upon the number of days the temperature is below zero between December and February; increase the Cold Weather Payment to all Age Concern gas customers over the age of 80 from £10 to £20. All customers on our Age Concern product also receive a free early warning hypothermia thermometer and four free low energy light bulbs, and all are eligible for further reduced energy efficiency measures.
Warm Front Scheme	Department for Environment, Food and Rural Affairs (Defra)	Energy Efficiency	Warm Front Scheme established in 2000 (previously called Home Energy Efficiency Scheme) provides grants to improve heating and energy efficiency of private sector housing in England. The grant provides energy-efficiency advice, energy-efficient light bulbs, and insulation measures such as cavity wall insulation, loft insulation, hot water thermal jackets, and heating improvements. The scheme is aimed at vulnerable households in receipt of eligible benefits. Warm Front also provides a Benefit Entitlement Check to maximise income. The Warm Front Grant provides a package of insulation and heating improvements up to the value of £2,700 (or £4,000 if oil central heating is recommended).
Warm Front £300 Heating Rebate Scheme	Department for Environment, Food and Rural Affairs (Defra)	Energy Efficiency	On Monday 5 December 2005, the Chancellor made a pre-budget announcement regarding the Government's intention to offer a £300 rebate off the cost of installing a new central heating system for people aged 60 or over who own or privately rent their home. The £300 rebate, which forms part of the Warm Front Scheme, can only be used by householders who either have no heating system or one which is inoperable. The £300 rebate was made available from 11 August 2006 to all householders aged 60 or over who are not in receipt of a qualifying Warm Front benefit.
Home Heat Helpline	Energy Retail Association and Energy Suppliers	Rate Assistance	This is an initiative supported by energy suppliers, aimed at helping to reduce the number of fuel-poor households. The main purpose of the helpline is to encourage vulnerable customers to speak with their energy suppliers either directly or through third parties. The helpline is staffed by trained advisers who can carry out a preliminary assessment of callers' benefit entitlement. They are also linked to each energy supplier's priority care team.
Community Energy Efficiency Fund (CEEF)	Department for Environment, Food and Rural Affairs (Defra)	Rate Assistance	Community Energy Efficiency Fund (CEEF) has been set up to provide financial support in 2007/08 to projects in England and applicants have been invited via a competitive process to apply. The aim is to ensure 300,000 of the most vulnerable pensioner and other vulnerable households are assisted to feel warmer and more comfortable using an area based approach to provide a coordinated set of ad vice and measures to them. Community Energy Efficiency Fund (CEEF) was launched on 13th June 2007 and is administered by Defra.
Energy Best Deal Campaign	Ofgem and the Citizens Advice Bureau	Rate Assistance	The objective of the project will be to provide training sessions for a wide range of front line advice workers as part of the CAB's financial capability work. The aim of the project will be to raise awareness among low-income consumers of the savings that can be made by switching supplier and/or payment method and help to provide reassurance about the switching process.
Low Carbon Buildings Programme	Department for Environment, Food and Rural Affairs (Defra)	Energy Efficiency	Pilot project within the low carbon buildings programme (LCBP) to introduce fuel saving microgeneration to fuel poor communities.
Energy Efficiency Commitment (EEC) / Carbon Emissions Reduction Target (CERT)	Energy Suppliers	Energy Efficiency	Across Great Britain, under the EEC, electricity and gas suppliers are required to meet targets for the promotion of improvements in household energy efficiency. In both the first phase of EEC (EEC1), 2002-05, and the current phase (EEC2), 2005-08, suppliers were required to focus at least 50% of energy savings on a Priority Group of low income consumers. Households in this group are those in receipt of income or disability based benefits or tax/pension credit, similar to the eligibility criteria for the Warm Front Scheme. The consultation proposals on the third phase of EEC 2008-11, now known as the Carbon Emissions Reduction Target, were published in May 2007. Also, that energy suppliers should be required to direct at least 40% of carbon savings to a Priority Group of those in receipt of income/disability based benefits or tax/pension credit or those who are aged 70 or over.
E.ON UK - CaringEnergy Service	E.ON UK	Rate Assistance	This includes energy efficiency advice and measures, a benefits entitlement check, a priority service register as well as a range of tariff and payment options. In 2007, we helped 21,000 customers through the CaringEnergy service and within the service over 1600 customers have benefitted from a Benefits Entitlement check.
StayWarm Tariff	E.ON UK	Rate Assistance	Exclusively designed for the over-60s, StayWarm offers customers a fixed price for all their energy by monthly Direct Debit. The amount they pay is based on the number of people who live in their home and the number of bedrooms their home has. We guarantee that as long as they remain with StayWarm, the price they pay will be fixed for 12 months from when they sign up. During 2007, we continued to hold prices for medium and high-user Staywarm customers on benefits, even though their consumptions would have warranted a price increase. These customers are amongst the most vulnerable of fuel poor customers. All are over 60, many live on their own and they require discounts of several hundred pounds as a means of alleviating fuel poverty.
Warm Deal	Scottish Government	Energy Efficiency	Warm Deal offers a grant for heating for households on particular benefits of up to a maximum of £500 for a range of energy saving measures. If you are aged 60 or over and not in receipt of income-related benefits, you can get a smaller grant of up to £125. The Home Energy Efficiency (Scheme) Scotland Regulations, effective from January 2007, also extended the Warm Deal programme to households with children with disabilities and receiving the Disability Living Allowance. These homes can have free insulation measures installed up to the value of £500.
Central Heating Programme / Over 80s Central Heating Programme	Scottish Government	Rate Assistance	Central Heating Programme provides free central heating and insulation packages to the over 60s. It is available to all households in the private sector who lack central heating and where the householder or partner is aged 60 or over. The Programme was extended in May 2004 to include householders (or partners) aged 80 or over who had partial or inefficient central heating systems. The programme has been further extended from 1 January 2007 to include homeowners aged between 60 and 79 and in receipt of the guaranteed element of Pension Credit are now eligible under the scheme if their home central heating is partial or inefficient.
Home Energy Efficiency Scheme (HEES Wales) / HEES Plus	Welsh Assembly Government	Energy Efficiency	The HEES grant provides a package of heating and insulation improvements up to the value of £3,600 (Oil Central Heating up to the value of £5,000). There are two levels of the grant; HEES is for householders who are pregnant and in receipt of a MAT B1 certificate or families with children under 16; provides grants up to to the value of £2,000. HEES Plus is for householders who are 60 and over, lone parents with children under 16 and persons who are receiving certain sickness or disability related benefits; provides grants up to to the value of £3,600. Partial grant of £500 for those over 60 that do not qualify for HEES/HEES Plus. All must be in receipt of the relevant benefits or allowances. The availability of these improvements will depend on what form of heating or insulation you have in your property. The HEES grant does not cover the cost of upgrading a working heating system. Households will also receive tailored energy efficiency advice, provided by eaga plc's Home Visits team. For those householders over the age of 80 they will automatically qualify for these grants.
Warm Homes - Northern Ireland / Warm Homes Plus	Northern Ireland - Department for Social Development	Rate Assistance	The Warm Homes and the Warm Homes Plus Schemes continue to be the main programme for tackling fuel poverty in Northern Ireland, through the provision of energy efficiency measures to owner-occupied and private sector homes. The Warm Homes grant provides a package of energy efficiency and heating measures, up to the value of £850. Energy efficiency advice, tailored to each household, is provided by eaga plc's Home Visits team in accordance with the Energy Savings Trust's Code of Practice. As part of Warm Homes Plus, those over 60 and who are in receipt of one of the necessary benefits are also eligible for heating measures, as well as the insulation measures offered as part of Warm Homes (The total grant available in this instance for both insulation and heating measures is £4,300).

Programs	Territories: England	Territories: Scotland	Territories: Wales	Territories: Northern Ireland	Funding Level	Funding Sources: Ratepayers (Voluntary / Mandatory)	Funding Sources: Provincial Tax / Surcharge	Funding Sources: Federal / Provincial Grants	Funding Sources: Charitable Contributions	Funding Sources: Other	Customer Eligibility Requirements: Households with Child under 16	Customer Eligibility Requirements: Seniors	Customer Eligibility Requirements: Poverty Level	Customer Eligibility Requirements: Disabled / Medical Condition / Need	Customer Eligibility Requirements: Other
Winter Fuel Payments	X				£2 billion			X				X			
Cold Weather Payments	X				£2.5 million in 2007			X			X	X	X	X	
Warm Front Scheme	X				£800 million for 2008-2011			X			X	X	X	X	
Warm Front £300 Heating Rebate Scheme	X							X				X			
Home Heat Helpline	X				£700 million over 3 years						X	X	X	X	
Community Energy Efficiency Fund (CEEF)	X												X		
Energy Best Deal Campaign	X				£150,000								X		
Low Carbon Buildings Programme	X				£3 million										Fuel poor communitie s
Energy Efficiency Commitment (EEC) / Carbon Emissions Reduction Target (CERT)	X				£1.2 billion					X					40% towards Priority Group of low income consumers
E.ON UK - CaringEnergy Service	X				£2 million for 3 years										
StayWarm Tariff	X											X	X		
Warm Deal		X						X				X		X	
Central Heating Programme / Over 80s Central Heating Programme		X						X				X			
Home Energy Efficiency Scheme (HEES Wales) / HEES Plus			X		£20 million			X			X	X	X	X	
Warm Homes - Northern Ireland / Warm Homes Plus				X	£20 million over two years			X			X	X	X	X	

Programs	Type of Assistance Offered: Monthly Service Charge	Type of Assistance Offered: Commodity Charge	Type of Assistance Offered: Security Deposit	Type of Assistance Offered: Reconnection Fee	Type of Assistance Offered: Late Payment Fee	Type of Assistance Offered: Arrearage	Type of Assistance Offered: Other	How is Assistance Determined?: Fixed Amount	How is Assistance Determined?: % of Total Bill	How is Assistance Determined?: Customer Usage	How is Assistance Determined?: Other	Source(s)
Winter Fuel Payments							Payments up to £400				Payments up to £400	"Winter Fuel Payments." The Pension Service: Part of the Department for Work and Pensions. 15 August 2008 <http://www.thepensionservice.gov.uk/home.asp> Morgan, Eluned. "Energy Poverty in the EU." PSE Socialist Group in the European Parliament. July 2008.
Cold Weather Payments							Payments up to £20				Payments up to £20	"Helping Customers with their Energy Needs." E.ON UK Annual Report 2007. <http://eon-uk.com/about/customersenergyneeds_vulnerablecustomers.aspx> Morgan, Eluned. "Energy Poverty in the EU." PSE Socialist Group in the European Parliament. July 2008.
Warm Front Scheme							Energy efficient improvements up to £2,700 (or £4,000 if oil central heating is recommended)				Energy efficient improvements up to £2,700 (or £4,000 if oil central heating is recommended)	"Fuel Poverty: How to Get Help." Energy: Fuel Poverty. Department for Business Enterprise & Regulatory Reform. 7 August 2008 <http://www.berr.gov.uk/energy/fuel-poverty/help/index.html> The Warm Front Grant <http://www.warmfront.co.uk/index.htm> Morgan, Eluned. "Energy Poverty in the EU." PSE Socialist Group in the European Parliament. July 2008.
Warm Front £300 Heating Rebate Scheme							Rebate of £300				Rebate of £300	"Warm Front £300 Heating Rebate Scheme." Government Contracts. eaga. 15 August 2008 <http://www.eaga.com/government_contracts/heating_rebate.html>
Home Heat Helpline							Helpline				Helpline	"Fuel Poverty: How to Get Help." Energy: Fuel Poverty. Department for Business Enterprise & Regulatory Reform. 7 August 2008 <http://www.berr.gov.uk/energy/fuel-poverty/help/index.html>
Community Energy Efficiency Fund (CEEF)												"Fuel Poverty: Local Activity." Climate Change & Energy - Action in the UK - Household Emissions - Fuel Poverty. June 2008. Department of Environment Food and Rural Affairs. 7 August 2008 <http://www.defra.gov.uk/environment/climatechange/uk/household/fuelpoverty/local/index.htm#ceef>
Energy Best Deal Campaign							Helpline				Helpline	"Help with fuel bills for the poorest consumers". News Release. Department of Environment Food and Rural Affairs. 30 May 2008. <http://www.defra.gov.uk/news/2008/080530a.htm>
Low Carbon Buildings Programme												"Help with fuel bills for the poorest consumers". News Release. Department of Environment Food and Rural Affairs. 30 May 2008. <http://www.defra.gov.uk/news/2008/080530a.htm>
Energy Efficiency Commitment (EEC) / Carbon Emissions Reduction Target (CERT)												"Energy supplier obligations: Carbon Emissions Reduction Target (CERT)." Environmental Protection - Sustainable Energy: Energy Efficiency. June 2008. Department for Environment Food and Rural Affairs. 15 August 2008 <http://www.defra.gov.uk/environment/climatechange/uk/household/supplier/cert.htm> The UK Fuel Poverty Strategy: 5th Annual Progress Report 2007.
E.ON UK - CaringEnergy Service												"Helping Customers with their Energy Needs." E.ON UK Annual Report 2007. <http://eon-uk.com/about/customersenergyneeds_vulnerablecustomers.aspx>
StayWarm Tariff							Fixed price for energy by monthly Direct Debit				Fixed price for energy by monthly Direct Debit	"Helping Customers with their Energy Needs." E.ON UK Annual Report 2007. <http://eon-uk.com/about/customersenergyneeds_vulnerablecustomers.aspx>
Warm Deal							Grants up to £500				Grants up to £500	"Warm Deal" People and Society - Older People - Home Improvements. August 2007. The Scottish Government. 15 August 2008 <http://www.scotland.gov.uk/Topics/People/OlderPeople/Homeimprovements/Warmdeal> Morgan, Eluned. "Energy Poverty in the EU." PSE Socialist Group in the European Parliament. July 2008.
Central Heating Programme / Over 80s Central Heating Programme							Free heating and insulation packages				Free heating and insulation packages	"Central Heating Programme." People and Society - Older People - Home Improvements. August 2007. The Scottish Government. 15 August 2008 <http://www.scotland.gov.uk/Topics/People/OlderPeople/Homeimprovements/Centralheating> Morgan, Eluned. "Energy Poverty in the EU." PSE Socialist Group in the European Parliament. July 2008.
Home Energy Efficiency Scheme (HEES Wales) / HEES Plus							Grants for energy efficiency improvements up to £3,600				Grants for energy efficiency improvements up to £3,600	The Home Energy Efficiency Scheme (HEES Wales) <http://www.heeswales.co.uk/index.htm> Morgan, Eluned. "Energy Poverty in the EU." PSE Socialist Group in the European Parliament. July 2008.
Warm Homes - Northern Ireland / Warm Homes Plus							Grant up to £4,300				Grant up to £4,300	"Warm Homes - Northern Ireland." Government Contracts. eaga. 15 August 2008 <http://www.eaga.com/government_contracts/warmerhomes.htm> The UK Fuel Poverty Strategy: 5th Annual Progress Report 2007.

				States								Funding Sources					Customer Eligibility Requirements					Type of Assistance Offered							How is Assistance Determined?			
Programs	Sponsor(s)	Program Type	Program Description	New South Wales	Queensland	South Australia	Tasmania	Victoria	Western Australia	Funding Level	Participation Level (Households)	Ratepayers (Voluntary / Mandatory)	State Tax / Surcharge	Federal / Provincial Grants	Charitable Contributions	Other	Families	Seniors	Income Level	Disabled / Medical Condition / Need	Other	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Other	Source(s)
Making Ends Meet - Federal Labor's Plan for Older Australians, People with Disabilities and Carers	Australian Government	Rate Assistance	Utilities Allowance: Utilities Allowance comprises of 4 instalments/year and is paid to: all age pension age customers on a qualifying income support payment; and customers of any age receiving Disability Support Pension, Carer Payment, Mature Age Allowance, Partner Allowance, Wife Pension, Widow B Pension, Bereavement Allowance or Widow Allowance; and Disability Support Pension and Carer Payment customers. (a) Utilities Allowance will increase from $107.20 a year to $500 a year for singles, and from $53.60 to $250 a year for each member of a couple; (b) Utilities Allowance will be paid quarterly rather than half yearly; (c) Single customers receiving Utilities Allowance will get $125 every 3 months; (d) Couples receiving Utilities Allowance will get $62.50 each every 3 months; (e) Utilities Allowance will be paid to recipients of Disability Support Pension, Carer Payment, Wife Pension, Widow B Pension and Bereavement Allowance. Your eligibility for Utilities Allowance is automatically assessed.	X	X	X	X	X	X	$5.1 billion over 5 years (incl. $530.4 million in 2007-2008)								X		X	Carer Payment; Wife Pension; Widow B Pension; Bereavement Allowance; Mature Age Allowance; Widow Allowance, and; Partner Allowance							A non-taxable payment; annual rate is $250.00 per member of a couple and $500.00 for single people (or members of a couple separated by illness); paid in 4 instalments/year to qualified income support payment recipients	X			"Utilities Allowance." Individuals: Payments - Concessions or Concession Cards. Centrelink, Australian Government. 8 August 2008 <http://www.centrelink.gov.au/internet/internet.nsf/payments/utilities_allowance.htm>
Coburg Solar City	Moreland Energy Foundation Ltd.	Energy Efficiency	"Energy Hub" is a community enterprise providing energy retrofit services for low income and public housing tenants. As well as smart meters, it will involve the installation of solar systems; discounts on energy efficient products and grants to install energy and water saving measures targeting community residential units, renters and families. The announced Solar Cities are Adelaide, Townsville, Blacktown, Alice Springs and Central Victoria. Expect around 1000 low income households to benefit from energy efficiency audits and retrofitting.	X	X	X	X	X	X	$4.9 million				X					X									Retrofit low income households for energy and water efficiency, such as insulation and shower heads				"Low-Income Households a Priority for Coburg Solar City." News Release. Department of the Environment, Water, Heritage and the Arts. 10 June 2008. <http://www.environment.gov.au/settlements/solarcities/>
Customer Assistance Programs / Financial Hardship Programs	Individual energy companies	Rate Assistance	Most energy and water companies in NSW provide customer assistance programs to help people who are having difficulty paying their bills. Eacl company is different, so you will need to contact your company to find out what assistance they offer and whether you are eligible.	X																								Payment Plans				"Payment assistance, rebates and customer assistance programs." EWON Payment Assistance: Supplier Assistance. Energy & Water Ombudsman NSW (EWON). 6 August 2008 <http://www.ewon.com.au/financial_help/index.html>
Energy Accounts Payment Assistance (EAPA)	State Government	Rate Assistance	Vouchers can be used to help pay electricity or natural gas bills. A NSW Government program to help people experiencing financial difficulty and is administered by the Department of Water and Energy. EAPA vouchers are distributed by community organisations for emergency or crisis situations only. EAPA can be used to pay for consumption of electricity or gas (but not LPG) and for service access charges (SAC). EAPA can't be used for charges such as a disconnection fee, late payment fee, meter test fee, service call charge or as a security deposit. Customers who have been disconnected can use EAPA to reduce the consumption amount of their bill. Under NSW law, a company can't disconnect your electricity if you are waiting to be assessed for EAPA.	X						$9.2 million												X						EAPA can be used to pay for consumption of electricity or gas (but not LPG) and for service access charges (SAC).				"Payment assistance, rebates and customer assistance programs." EWON Payment Assistance. Energy & Water Ombudsman NSW (EWON). 6 August 2008 <http://www.ewon.com.au/financial_help/index.html>
NSW Energy Rebate for Pensioners	State Government	Rate Assistance	If you are a pensioner you may be eligible to receive a rebate to help pay your electricity and gas bills. The rebate will appear on your electricity bill. Increased pensioner energy rebates from $112 to $130 per annum, indexed to the movement in CPI	X						$65.0 million over 5 years																						assistance programs." EWON Payment Assistance: Rebates. Energy & Water Ombudsman NSW (EWON). 6 August 2008 <http://www.ewon.com.au/financial_help/index.h
Life Support Rebate	State Government	Rate Assistance	If you require certain medical equipment in your home that is necessary to sustain your life, for example a kidney dialysis machine or respirator/ventilator, you may entitled to a rebate on your electricity bill. The life support rebate is additional to any pensioner rebate to which yo may be entitled.	X						2005-06: $2.7 million																						"Payment assistance, rebates and customer assistance programs." EWON Payment Assistance: Rebates. Energy & Water Ombudsman NSW (EWON). 6 August 2008 <http://www.ewon.com.au/financial_help/index.html>
Reticulated Natural Gas Rebate	State Government	Rate Assistance	The rebate scheme currently provides a rebate of $55 per year to eligibl concession card holders in Queensland using reticulated natural gas. The rebate, has been backdated to 1 July 2007, to assist eligible concession card holders to meet the increased supply costs of reticulated natural gas. The rebate amount will increase to $57.65 a yea from 1 July 2008 in line with the Consumer Price Index.		X					$5.8 million	50,000																	Fixed Rebate Amount	X			"Reticulated Natural Gas Rebate." Department of Mines and Energy: Gas Retail Prices. Queensland Government. 8 August 2008 <http://www.dme.qld.gov.au/Energy/gas_pensioner_rebate.cfm>
Electricity Rebate	State Government	Rate Assistance	A rebate of $0.3968 per day/approx. $36.20 per quarter (inclusive of GST) applies to the cost of electricity supplied to the home of the eligible concession card holder. Eligible card holders must be the registered consumer of an electricity retailer at premises that are their principal place of residence and the only premises for which the rebate is claimed, and live alone or share the home with: their spouse; other persons who hold a Pensioner Concession Card or Queensland Seniors Card; other persons wholly dependent on them; other persons who receive an income support payment from Centrelink, the Family Assistance Office or the Department of Veterans' Affairs who do not pay rent, or; other persons who live with the card holder to provide care and assistance, and who do not pay rent. Eligible card holders who live in caravan parks or other multi-residential buildings may be eligible for the electricity rebate if: electricity is paid on the basis of individually metered consumption, and; the owner/proprietor is prepared to seek the electricity rebate on behalf of the resident.		X					$86.5 million													X						X			"State Government concessions: Electricity." Queensland Government Concessions: Concessions brochure. April 2008. Queensland Government. 8 August 2008 <http://www.communities.qld.gov.au/community/concessions/brochure/stategovt/electricity.html>
Electricity Life Support Concession	State Government	Rate Assistance	The Electricity Life Support Concession Scheme offers a concession of $24.64 per month (paid quarterly) per machine for eligible users of an oxygen concentrator or $16.47 per month (paid quarterly) for eligible users of a kidney dialysis machine to assist with meeting electricity costs. The scheme provides financial assistance to seriously ill people who use home-based life support systems (oxygen concentrators or kidney dialysis machines) provided they have been medically assessed in accordance with the eligibility criteria determined by Queensland Health.		X					$0.8 million										X								Fixed Rebate Amount	X			"State Government concessions: Electricity life support." Queensland Government Concessions: Concessions brochure. April 2008. Queensland Government. 8 August 2008 <http://www.communities.qld.gov.au/community/concessions/brochure/stategovt/electricity.html>
Home Energy Emergency Assistance (HEEA) Scheme	State Government	Rate Assistance	The HEEA scheme is a Queensland Government scheme designed to help people who are experiencing a crisis or unforseen emergency that is limiting their ability to pay their home electricity or natural gas bill and are under threat of disconnection.		X					$2.7 million																						"Payment assistance & rebates." Consumers: Payment Assistance & Rebates. Energy Ombudsman Queensland (EOQ). 8 August 2008 <http://www.eoq.com.au/payment_assistance_&_rebates.cfm>
Energy Concession	State Government	Rate Assistance	A concession of up to $120 per year on your household energy bills, which covers both electricity and gas use (including LPG bottled gas). You may be eligible if you are: (a) an eligible pensioner; (b) Commonwealth Seniors Health Card Holder; (c) one of a couple receiving a Centrelink benefit; (d) hold a Department for Veteran's Affair Gold Card marked 'War Widow, TPI or EDA'; (e) a single person in receipt of an approved Centrelink benefit or allowance (applicable from 1 July 2005); (f) a full-time student receiving Austudy / Abstudy (including couples) (applicable from 1 July 2005). In addition to the above: (a) you must permanently reside in your home; and (b) you must not share your home with anyone earning an income of more than $3,000 per year, unless that person is a spouse/ partner/ dependant or is in receipt of a pension, benefit or allowance from Centrelink or the Department of Veterans' Affairs.			X				$28.1 million (2005-2006)								X		X	Also, one of a couple receiving a Centrelink benefit; hold a Department for Veteran's Affairs Gold Card marked 'War Widow, TPI or EDA'; a single person in receipt of an approved Centrelink benefit or allowance; a full-time student receiving Austudy /Abstudy (including couples)										Up to $120 per year	"Energy Conession." DFC Services & Programs: Concessions. July 2008. Government of South Australia. 8 August 2008 <http://www.familiesandcommunities.sa.gov.au/Default.aspx?tabid=1604>

				States								Funding Sources					Customer Eligibility Requirements					Type of Assistance Offered							How is Assistance Determined?			
Programs	Sponsor(s)	Program Type	Program Description	New South Wales	Queensland	South Australia	Tasmania	Victoria	Western Australia	Funding Level	Participation Level (Households)	Ratepayers (Voluntary / Mandatory)	State Tax / Surcharge	Federal / Provincial Grants	Charitable Contributions	Other	Families	Seniors	Income Level	Disabled / Medical Condition / Need	Other	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Other	Source(s)
Energy Friends	State Government	Energy Efficiency	Energy Friends is a partnership program of the South Australian Government. Community groups that sign up to the Energy Friends program will receive training and practical resources to allow their members to undertake grass-roots energy action in their local community. (Includes Home Energy Audits)			X																										"Energy friends." Government Programs. April 2008. Department for Transport, Energy and Infrastructure (DTEI). 8 August 2008 <http://www.energy.sa.gov.au/government_programs/energy_friends>
Healthcare and Electricity Concession	State Government	Rate Assistance	This electricity discount is available to Centrelink Health Care card holders and is administered by Aurora Energy on behalf of the Department of Health and Human Services. The discount is 85.43 cents per day all year round and eligible customers do not need to reapply each year. It is not possible to receive this discount in conjunction with the pensioner electricity concession.				X			$23.4 million										X									X			"Discounts and concessions." Residential: Rates changes and discounts. Aurora Energy. 8 August 2008 <http://www.auroraenergy.com.au/residential/rates_charges_and_discounts/discounts_and_concessions.asp> "Electricity and Heating." Tasmanian Government Concessions 2008-2009. July 2008. Tasmania Department of Premier and Cabinet. 8 August 2008 <http://www.dpac.tas.gov.au/concessions/concessions08-09/electricity_and_heating>
Pensioner Electricity Concession	State Government	Rate Assistance	The pensioner concession is given to Tasmanian pensioners who have Pensioner Concession Card issued by Centrelink or the Department of Veterans Affairs. It is administered by Aurora Energy on behalf of the Department of Health and Human Services. Pensioners need only register for this electricity discount once. You will continue to receive the pensioner rebate of 85.43 cents per day all year round and do not need to reapply each year. It is not possible to receive the healthcare card concession in conjunction with the pensioner electricity concession.				X			$9.8 million																			X			"Discounts and concessions." Residential: Rates changes and discounts. Aurora Energy. 8 August 2008 <http://www.auroraenergy.com.au/residential/rates_charges_and_discounts/discounts_and_concessions.asp> "Electricity and Heating." Tasmanian Government Concessions 2008-2009. July 2008. Tasmania Department of Premier and Cabinet. 8 August 2008 <http://www.dpac.tas.gov.au/concessions/concessions08-09/electricity_and_heating>
Heating Allowance Rebate	State Government	Rate Assistance	A means tested heating allowance is available at a rate of $56 per year to assist eligible pensioners with their cost of heating. A payment of $28 is paid twice a year in May and September. This scheme is not limited to electricity as the energy source and is not administered by Aurora Energy. The heating allowance is administered by the Department of Health and Human Services. A single pensioner must not have more than $1,750 in cash assets and married/de facto pensioners must not have more than $2,750 (other conditions apply).				X																						X			"Discounts and concessions." Residential: Rates changes and discounts. Aurora Energy. 8 August 2008 <http://www.auroraenergy.com.au/residential/rates_charges_and_discounts/discounts_and_concessions.asp> "Electricity and Heating." Tasmanian Government Concessions 2008-2009. July 2008. Tasmania Department of Premier and Cabinet. 8 August 2008 <http://www.dpac.tas.gov.au/concessions/concessions08-09/electricity_and_heating>
Life Support Discount	State Government	Rate Assistance	Aurora Energy provides an electricity discount to customers who use an approved life support system, or live with someone who uses one. The discount is about fifty per cent of the cost to run the life support system.				X																									"Discounts and concessions." Residential: Rates changes and discounts. Aurora Energy. 8 August 2008 <http://www.auroraenergy.com.au/residential/rates_charges_and_discounts/discounts_and_concessions.asp> "Electricity and Heating." Tasmanian Government Concessions 2008-2009. July 2008. Tasmania Department of Premier and Cabinet. 8 August 2008 <http://www.dpac.tas.gov.au/concessions/concessions08-09/electricity_and_heating>
Utility Relief Grant Scheme	State Government	Rate Assistance	Administered and funded by the State Government, provides assistance to domestic customers who are unable to pay their utility bills due to short-term financial crisis. Financial assistance is available on electricity gas and water bills. Pensioner Concession Card, Health Care Card, Gol Card holders and low income households who are registered with their utility retailer' hardship program are eligible to apply to the Scheme. Applicants must demonstrate that an unexpected hardship has left them seriously short of money so that they cannot pay their utility bill without assistance, and risk disconnection of supply. In addition, applicants must satisfy at least one of the following criteria: (a) have experienced a significant increase in bills, for example, if caused by a faulty appliance; (b) have experienced a recent decrease in income, for example, if caused by unemployment, illness or breakdown of a household; (c) have experienced high unexpected expenses on essential items, for example, funeral costs or repairs/replacement of essential items; (d) cost of their shelter is more than 30% of the household income; or (e) cost of their ut					X		2005/06: $3.2 million	2005/06: 9,401							X	X	X								The grant provides for either the full or partial payment of an outstanding utility bill, with a maximum grant of six months worth of usage.		X	The grant provides for either the full or partial payment of an outstanding utility bill, with a maximum grant of six months worth of usage.	"Financial assistance and emergency relief." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/financial-assistance-and-emergency-relief>
Non-Mains Utility Relief Grant Scheme	State Government	Rate Assistance	The Non-Mains Utility Relief Grant is available to customers who are unable to pay their outstanding bottled gas accounts or non-mains/carted water accounts. Applicants must demonstrate that they meet the set eligibility criteria, which are the same as the Utility Relief Grant Scheme. Non-concession cardholders who are low income earners and are committed to a payment plan.					X		2005/06: $22,826	2005/06: 83 grants							X	X	X												"Financial assistance and emergency relief." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/financial-assistance-and-emergency-relief>
Capital Grants Scheme	State Government	Rate Assistance	The Capital Grants Scheme provides once-off assistance to concession card households by repairing or replacing essential water, gas or electrical appliances for households who otherwise could not afford to d so, due to financial hardship. The applicant must demonstrate they have no savings to meet the cost of the faulty appliance.					X		2005/06: $0.2 million	2005/06: 177 grants							X		X												"Financial assistance and emergency relief." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/financial-assistance-and-emergency-relief>
Winter Energy	State Government	Rate Assistance	Discount of 17.5% off mains electricity and mains gas bills issued durinc a 6-month period between May and November.					X		2005/06: $45.8 million (electricity) + $37.0 million (gas)	2005/06: 724,989 (electricity) + 541,254 (gas)							X		X												"Energy Concessions." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/energy>
Non-Mains Winter Energy	State Government	Rate Assistance	A three-tiered annual rebate available to people who: Spend $80 or mor on liquefied petroleum gas (LPG) each year; or Spend $80 or more on alternative fuel used as the main domestic energy source (diesel, petrol, heating oil). A $19 rebate is available for purchases from $80–$119, a $95 rebate for purchases from $120–$595 and a rebate of $141 for purchases greater than $595 (2006 amounts). Rebate amounts are adjusted annually in line with increases in the price of LPG. Who are individually metered and billed for electricity, but who pay a caravan par or accommodation owner.					X		2005/06: $1.88 million	2005/06: 22,085							X		X												"Energy Concessions." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/energy>
Life Support Machines	State Government	Rate Assistance	A quarterly rebate applied to electricity bills where a cardholder or a member of the household utilises certain life support machines includinc oxygen concentrators and haemodialysis machines.					X		2005/06: $0.7 million	2005/06: 3,199							X		X												"Energy Concessions." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/energy>
Summer Multiple Sclerosis Concession	State Government	Rate Assistance	A 17.5% discount on the final quarterly summer electricity bill to assist with the costs of summer electrical cooling where a cardholder or a household member has Multiple Sclerosis. The concession may be extended to other qualifying medical conditions if a person is unable to regulate their own body temperature e.g. Parkinson's disease, motor neurone disease, quadriplegia.					X		2005/06: $0.1 million	2005/06: 5,638									X												"Energy Concessions." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/energy>

				States								Funding Sources					Customer Eligibility Requirements					Type of Assistance Offered							How is Assistance Determined?			
Programs	Sponsor(s)	Program Type	Program Description	New South Wales	Queensland	South Australia	Tasmania	Victoria	Western Australia	Funding Level	Participation Level (Households)	Ratepayers (Voluntary / Mandatory)	State Tax / Surcharge	Federal / Provincial Grants	Charitable Contributions	Other	Families	Seniors	Income Level	Disabled / Medical Condition / Need	Other	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Other	Source(s)
Group Homes Winter Energy	State Government	Rate Assistance	Discount of 17.5% off the mains electricity and mains gas bills issued during a 6-month period between May and November. The Group Homes Winter Energy concession only applies if tenants/ residents are responsible for paying the energy accounts; accounts apply to domestic tariff and are issued in the name of the organisation.					X		Included in Winter Energy	2005/06: 37 organizations										Certain conditions apply for the organisation and the account to be eligible.											"Energy Concessions." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/energy>
Electricity Transfer Fee Waiver	State Government	Rate Assistance	Waiver of transfer fee payable to electricity retailer when there is a change of occupancy. Note: The transfer fee waiver is not applicable to newly constructed residences.					X		2005/06: $0.8 million	2005/06: 37,061							X		X												"Energy Concessions." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/energy>
Service to Property Charge	State Government	Rate Assistance	Reduction on the supply charge for concession households with low energy consumption. The Service to Property Charge concession is applied if the cost of electricity used is less than the supply (or service) charge. That charge is then reduced to the same price as the electricity usage cost. Concession is available all year.					X		2005/06: $1.6 million	2005/06: 32,028							X		X												"Energy Concessions." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/energy>
Off-Peak Concession	State Government	Rate Assistance	Reduction of 13% on the off-peak tariff consumption charges components of the electricity bill. The concession is available all year. Note: Off-peak tariffs are mostly used for electric hot water systems and electric floor heating.					X		2005/06: $5.1 million	2005/06: 164,138							X		X												"Energy Concessions." Victorian State Concessions. February 2008. State Government of Victoria, Australia, Department of Human Services. 8 August 2008 <http://www.office-for-children.vic.gov.au/concessions/concessions/energy>
Energy Rebate Scheme	State Government	Rate Assistance	The State provides an energy subsidy to people who are financially disadvantaged. The subsidy is intended to assist with the costs of buying energy of all types (electricity, gas, fuel oil, wood, etc.). However for administrative simplicity, the subsidy is paid through Western Power as a rebate on some electricity costs to residential customers who are holders of eligible concession cards. Holders of Centrelink Health Care Card, Seniors Health Card, Veteran Affairs Gold Cards (War Widow, Dependant, Totally and Permanently Incapacitated), and Pensioner Concession Card are entitled to reduced fees on meter testing and rebates on: Account establishment fee; and Supply charge. Where dependant children are listed on eligible Centrelink cards, customers are also entitled to a rebate on a proportion of the energy charge. Holders of Seniors Cards are entitled to reduced fees on meter testing and to rebates on: Supply Charge. This rebate is also available to eligible permanent caravan and park home residents.						X	$3.1 million (2006)								X	X	X												"State Government Energy Rebate Scheme." Fo Consumers: Subsidies and Rebates. Office of Energy, Government of Western Australia. 8 August 2008 <http://www.energy.wa.gov.au/3/3207/64/state_governmen.pm>
Seniors' Air Conditioning Rebate	State Government	Rate Assistance	Horizon Power provides to eligible seniors a rebate equivalent to the cos of 200kWh of electricity per applicable month to offset the electricity costs associated with operating an air conditioner. The rebate applies: (a) For a specified period depending on where you live; (b) To accounts registered in the applicant's name unless electricity is supplied through a submeter; and (c) For electricity supplied at residential tariff rates (A2). To be eligible for the rebate you must hold a valid Western Australian Seniors Card AND either a Pensioner Concession Card OR a Commonwealth Seniors Health Card.						X	Included in Energy Rebate Scheme								X														"Rebates and Subsidies." Residential: Prices, Fees & Rebates. December 2007. Horizon Power. 8 August 2008 <http://www.horizonpower.com.au/residential/about_account/prices_fees/rebates.html>
Life Support Equipment Electricity Subsidy	State Government	Rate Assistance	This Scheme provides a subsidy to compensate financially disadvantaged persons for the electricity costs of operating life support equipment at home. More specifically, the Scheme is aimed at people who are dependent on specified life support equipment used in their homes under specialist medical advice and are holders of concession cards that are means tested.						X	$0.56 million									X	X												"Rebates and Subsidies." Residential: Prices, Fees & Rebates. December 2007. Horizon Power. 8 August 2008 <http://www.horizonpower.com.au/residential/about_account/prices_fees/rebates.html>
Thermoregulatory Dysfunction Energy Subsidy Scheme	State Government	Rate Assistance	The State Government has introduced a new power bill subsidy for West Australians who suffer from chronic medical conditions which prevents them from controlling their own body temperature. This subsidy helps pay for domestic heating or cooling systems. The new $335 annual subsidy is enough to pay for the operation of a room-sized reverse cycle air-conditioner for six hours every day of the year.						X	$0.5 million										X												"Rebates and Subsidies." Residential: Prices, Fees & Rebates. December 2007. Horizon Power. 8 August 2008 <http://www.horizonpower.com.au/residential/about_account/prices_fees/rebates.html>

					Funding Sources					Customer Eligibility Requirements					Type of Assistance Offered							How is Assistance Determined?			
Programs	Sponsor(s)	Program Type	Program Description	Funding Level	Ratepayers (Voluntary / Mandatory)	Provincial Tax / Surcharge	Federal / Provincial Grants	Charitable Contributions	Other	Families	Seniors	Income Level / Community Services Card	Disabled / Medical Condition / Need	Other	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Other	Source(s)
ENERGYWISE Home Grants	Energy Efficiency and Conservation Authority	Energy Efficiency	EECA's ENERGYWISE™ home grants programme funds improvements to insulation and other energy efficiency measures for homes throughout the country. To be eligible for funding: (1) your property must have been built prior to 1978, when insulation in New Zealand homes became mandatory; (2) you must be eligible for a community services card. The home grants programme targets households on low-incomes; (3) people with health problems such as asthma and other respiratory illnesses are in some areas given priority because of the significant health benefits insulation provides. You are not eligible for a subsidy if you are a Housing New Zealand tenant.				X					X	X								Subsidy for energy efficiency improvements			Subsidy for energy efficiency improvements	"ENERGYWISE Home Grants." Residential Projects. Energy Efficiency and Conservation Authority. 15 August 2008 <http://www.eeca.govt.nz/residential/energywise-home-grants/index.html> "Funding for Homeowners who have a Community Services Card." Funding Available. ENERGYWISE. 15 August 2008 <http://www.energywise.govt.nz/funding-available/community-services-card-homeowners.html>
National Rental Property Insulation Programme	Energy Efficiency and Conservation Authority	Energy Efficiency	Currently landlords are being offered a subsidy of at least 60% on insulation and other energy efficiency measures for existing rental properties occupied by low-income tenants. There are two organisations that do this work on rental properties – Eco Insulation and EECN (Energy Efficiency Community Network). To be eligible: (1) the tenant named on the tenancy agreement must be eligible for a Community Services Card; (2) the property must have been built before 1978; (3) the property should have insufficient ceiling and/or underfloor insulation rent must not be increased within six months of receiving the subsidy.				X					X									Subsidy of 60% for energy efficiency improvements			Subsidy of 60% for energy efficiency improvements	"New Nationwide Rental Project." Residential Projects: Home Grants. Energy Efficiency and Conservation Authority. 15 August 2008 <http://www.eeca.govt.nz/residential/energywise-home-grants/new-nationwide-rental-project.html> "Funding for Landlords with Low-Income Tenants" Funding Available. ENERGYWISE. 15 August 2008 <http://www.energywise.govt.nz/funding-available/landlords.html>
ENERGYWISE Funding	Energy Efficiency and Conservation Authority	Energy Efficiency	The funding will be available to homeowners earning less than $100,000 pa (1 or 2 earners) or $140,000 pa (3 or more earners), with houses or other dwellings built before 1 April 1978. It will also be available to private residential landlords, where they are insulating and applying other energy efficiency measures to residential properties built before 1 April 1978. This programme is looking to reach a wider population group and will include middle income households. Funding is limited to primarily cover the cost of the interest. Home grants targets Community Services Card holders and offers higher levels of funding. Partners will provide access to loan capital for customers. They can provide this directly or establish partnerships with banks or other reputable lenders. EECA will provide an interest subsidy for qualifying customers. A maximum interest subsidy of $1,400 (incl GST) will be paid in respect of any one loan/customer. If customers prefer a grant to an interest subsidy, EECA will pay partners an amount equivalent to 10% of the capital cost of core products purchased (incl. GST), up to a	$23 million for 4 years			X					X									Interest subsidy of $1,400 OR Grant maximum of $530			Interest subsidy of $1,400 OR Grant maximum of $530	"ENERGYWISE Funding for Insulation and Clean Household Heating." Residential Projects. Energy Efficiency and Conservation Authority. 15 August 2008 <http://www.eeca.govt.nz/residential/energywise-funding/index.html>
Clean Heat Programme	Energy Efficiency and Conservation Authority	Energy Efficiency	EECA's clean heat programme is working towards cleaner air, making homes warmer and drier, achieving better health, and efficient use of energy. Through this programme inefficient open fires and solid fuel burners are removed from New Zealand homes and replaced with clean, efficient and sufficiently sized heating appliances. The programme currently targets homes of low income householders situated in a critical air shed area. A critical air shed area is an area of high pollution where the National Environmental Standards (NES) for air quality have been exceeded at least five times in the last 12 months. This programme is funded by the Ministry for the Environment. If you are eligible for a clean heat grant you will pay no more than $500 to replace your home's inefficient heating appliance. Full assistance provides for the full cost of the conversion and complete project management including: the retrofitting of necessary insulation to meet building standards where possible; the removal or sealing up of the existing solid fuel burner or fireplace; and the provision and installation of a	$50 million over 11 years			X					X									Grant			Grant	"Clean Heat" Residential Projects. Energy Efficiency and Conservation Authority. 15 August 2008 <http://www.eeca.govt.nz/residential/clean-heat/index.htm> "Full Assistance for Community Service Card Holders." Clean Heat Project. Environment Canterbury. 15 August 2008 <http://www.cleanheat.org.nz/full-assistance.php>

					Funding Sources					Customer Eligibility Requirements					Type of Assistance Offered							How is Assistance Determined?			
Programs	Sponsor(s)	Program Type	Program Description	Funding Level	Ratepayers (Voluntary / Mandatory)	Provincial Tax / Surcharge	Federal / Provincial Grants	Charitable Contributions	Other	Families	Seniors	Income Level / Community Services Card	Disabled / Medical Condition / Need	Other	Monthly Service Charge	Commodity Charge	Security Deposit	Reconnection Fee	Late Payment Fee	Arrearage	Other	Fixed Amount	% of Total Bill	Other	Source(s)
Warm Homes	MainPower	Energy Efficiency	To be eligible for the programme your property must have been built before 1978 and you must: (1) Hold a current Community Services Card and own your own home or; (2) Be a private sector landlord whose tenant holds a current Community Services Card. The programme covers all areas within North Canterbury and Kaikoura. Offer for Owner-Occupiers - 75% discount on supply and installation of: Ceiling insulation to R3.2; Under floor insulation to R1.4; Door and window draught stopping; Hot water cylinder wraps and lagging of first metreof hot water pipe; Energy efficient light bulbs will also be supplied and installed free of charge. Offer for Landlords - 50% discount on supply and installation of: Ceiling insulation to R3.2; Under floor insulation to R1.4; Door and window draught stopping; Hot water cylinder wraps and lagging of first metreof hot water pipe; Energy efficient light bulbs will also be supplied and installed free of charge. Note that in order to qualify, the tenant living in the property must hold a current Community Services Card.									X									Subsidy			Subsidy	"Warm Homes Promotion." Energy Efficiency and Conservation. MainPower. 15 August 2008 <http://www.mainpower.co.nz/index.cfm/1,85,276,42,html/Warm-Homes-Promotion>

Attachment 25.1

every little bit

HOME IMPROVEMENT INCENTIVES

Energy Efficiency Incentives for
Existing Residential Homes in
Washington & Idaho

For more information or to request additional brochures, please call 800-227-9187

NAME____

PHONE__________/_______________________________

AVISTA ACCT.#_____________________________________

SERVICE ADDRESS__________________________________

CITY____________________________STATE___ZIP________

MAILING ADDRESS__________________________________

CITY____________________________STATE___ZIP________

I hereby request an incentive for the listed work. Attached are the original invoices or legible copies. I have read the "Energy Efficiency Incentive Agreement" on the back of this form and agree to the conditions for participation in this program. I also understand that Avista will make the final determination of any incentive that I may receive. Programs are subject to change without notice. Request for incentive must be submitted within 90 days of completion of energy efficiency measure. *Please allow 6 to 8 weeks for processing.*

SIGNATURE ______________________________ DATE ______________

WA/ID HOME IMPROVEMENT INCENTIVE FORM

Fill out each section that applies. Attach original invoices or legible copies. Incomplete forms cannot be processed. Request for incentive must be submitted within 90 days of completion of project.

HIGH EFFICIENCY EQUIPMENT

☐ **High Efficiency Natural Gas Furnace/Boiler - $400**

HEATING EFFICIENCY[1] | BRAND | MODEL NUMBER | DATE COMPLETE | COST

☐ **High Efficiency Air Source Heat Pump - $400** ☐ **High Efficiency Ground Source Heat Pump - $1500** ☐ **Manufactured Home**

HEATING EFFICIENCY[1] | COOLING EFFICIENCY[1] | BRAND | MODEL # | DATE COMPLETE | COST | COP[1] (GROUND SOURCE)

☐ **Variable Speed Motor - $100**

BRAND | MODEL NUMBER | DATE COMPLETE | COST

☐ **High Efficiency Electric Water Heater - $50**

EFFICIENCY RATING[1] | BRAND | MODEL NUMBER | DATE COMPLETE | COST

☐ **High Efficiency Natural Gas Water Heater/Tank Type - $50** ☐ **High Efficiency Natural Gas Water Heater/Tankless - $200**

EFFICIENCY RATING[1] | BRAND | MODEL NUMBER | DATE COMPLETE | COST

☐ **High Efficiency Central Air Conditioner - $350**

EFFICIENCY RATING[1] | BRAND | MODEL NUMBER | DATE COMPLETE | COST

[1]Efficiency Rating is **AFUE** (Annual Fuel Utilization Efficiency) for furnaces/boilers, **EF** (Energy Factor) for water heaters, **HSPF** and **SEER** (Heating Seasonal Performance Factor and Seasonal Energy Efficiency Ratio) for Heat Pumps and **COP** (Coefficient of Performance) for ground source heat pumps.

CONVERSION FROM ELECTRIC STRAIGHT RESISTANCE

☐ **Electric to Natural Gas Wall Heater - $500**

☐ Electric Baseboard ☐ Forced-Air Furnace

PREVIOUS HEAT SOURCE | BRAND | MODEL NUMBER | DATE COMPLETE | COST

☐ **Electric to Natural Gas Furnace - $1000**

☐ Electric Baseboard ☐ Forced-Air Furnace

PREVIOUS HEAT SOURCE | BRAND | MODEL NUMBER | DATE COMPLETE | COST

☐ **Electric to Air Source Heat Pump - $1000** ☐ **Electric to Ground Source Heat Pump - $1000**

☐ Electric Baseboard ☐ Forced-Air Furnace

PREVIOUS HEAT SOURCE | BRAND | MODEL NUMBER | DATE COMPLETE | COST

☐ **Electric to Natural Gas Water Heater - $250**

BRAND | MODEL NUMBER | DATE COMPLETE | COST

WEATHERIZATION

☐ **Attic Insulation - 25¢ per sq ft.**

☐ Electric ☐ Natural Gas

SQUARE FOOTAGE | OLD R-VALUE | NEW R-VALUE | DATE COMPLETE | PRIMARY HEAT SOURCE | COST

☐ **Wall Insulation - 50¢ per sq ft.**

☐ Electric ☐ Natural Gas

SQUARE FOOTAGE | OLD R-VALUE | NEW R-VALUE | DATE COMPLETE | PRIMARY HEAT SOURCE | COST

☐ **Floor Insulation - 50¢ per sq ft.**

☐ Electric ☐ Natural Gas

SQUARE FOOTAGE | OLD R-VALUE | NEW R-VALUE | DATE COMPLETE | PRIMARY HEAT SOURCE | COST

☐ **Windows - $3.00 per sq ft.**

☐ Electric ☐ Natural Gas

BRAND | SQUARE FOOTAGE | NEW U-FACTOR | DATE COMPLETE | PRIMARY HEAT SOURCE | COST

Program Eligibility & Guidelines The following incentives are available for residential energy efficiency measures. Space heating and weatherization offers apply to residential homeowners in Washington and Idaho who heat their homes primarily with Avista electricity or natural gas. Water heating offers apply to customers heating with Avista electric or natural gas. Conversion offers apply to Avista electric resistance heat customers only. Please see descriptions for complete incentive requirements. All programs are subject to change and **request for rebate must be submitted within 90 days** of job completion. Offers apply to existing homes, for new construction please refer to the residential incentives for new construction.

HIGH EFFICIENCY EQUIPMENT

Natural Gas Furnace/Boiler A $400 incentive is available for installation of a high efficiency natural gas furnace or boiler of 90% AFUE (efficiency) or greater.

Air Source Heat Pump A $400 incentive is available for installation of a high efficiency air source heat pump of 8.5 HSPF (heating efficiency) (7.7 HSPF and 13.0 SEER for manufactured homes. Please make note on form to indicate manufactured home). **HSPF verification requires an ARI Certificate.**

Ground Source Heat Pump A $1500 incentive is available for installation of a ground source heat pump of 3.5 COP or greater. This may not be combined with any other high efficiency incentives.

Variable Speed Motor A $100 incentive is available for installation of a primary heating system that incorporates a variable speed motor. This incentive may be combined with a high efficiency incentive.

Central Air Conditioner A $350 incentive is available for replacing an old but functioning central air conditioning system with a new high efficient model of 14.0 SEER or better. Central air conditioning in this case is defined as a ducted air conditioning system of 1.5 tons (18,000 BTUs) cooling or higher, conditioning at least 75% of the home. This incentive may not be combined with heat pump or variable speed motor incentives. **SEER verification requires an ARI Certificate.**

Water Heater A $50 incentive is available for installation of an electric water heater (tank type) of 0.93 EF (efficiency) or greater; a natural gas water heater (tank type) of 0.60 EF or greater for 50-gallon, 0.62 EF or greater for 40-gallon. A $200 incentive is available for an instantaneous natural gas model (tankless) of 0.82 EF or higher.

CONVERSIONS FROM ELECTRIC

Replacement of Electric Straight Resistance as Primary Heat A $1,000 incentive is available to Avista electric customers who replace electric straight resistance as their primary heat (i.e. electric forced air furnace or electric baseboard heat) with a central natural gas heating system or central heat pump. This incentive may be claimed in addition to the high-efficient incentive. A $500 incentive is available to replace Avista electric heat with a natural gas wall heater.

Electric to Natural Gas Water A $250 incentive is available to Avista electric customers who replace an electric water heater with a new natural gas water heater. This incentive may be claimed in addition to the high-efficient natural gas water heater incentive.

WEATHERIZATION

Insulation Incentives are available for the addition of new insulation that increases the R-Value by R-10 or greater (both fitted/batt type and blown-in). Insulation must be installed only where such cavities separate conditioned from unconditioned areas of the residence.

Ceiling/Attic A 25 cents per square foot incentive is available if existing insulation level is R-19 or less.

Wall and Floor A 50 cents per square foot incentive is available if existing insulation level is R-5 or less. Any insulation installed outside the cavity, such as siding applications, does not meet incentive requirements..

Windows A $3.00 incentive, per square foot of qualifying windows installed, is available to customers who heat with Avista electric or natural gas for the upgrade of windows with a u-factor of .35 or lower. The lower the u-factor, the more efficient the window. Windows must be rated by a recognized organization such as the National Fenestration Rating Council (NFRC) or Department of Energy (DOE). **Square footage, u-factor ratings, and cost must be itemized on the invoice in addition to being listed on the rebate form.**

Attach originals or legible copies of your receipts and mail to:
Residential Incentives Avista - MSC-15 P.O. Box 3727 Spokane, WA 99220-3727

WA/ID ADDITIONAL CONDITIONS

- The incentives listed are applicable to existing single and multifamily residences (up to a fourplex), including manufactured and modular homes.
- Incentives are not available for seasonal or recreational homes; they must be a primary living residence.
- Homeowners are responsible for complying with all applicable codes and regulations.
- Homeowners installing both a high efficient natural gas furnace and high efficient air source heat pump are eligible for both high efficiency incentives. Ground source heat pumps cannot be combined with any other high efficiency incentive.
- Homeowners converting from electric heat may only receive one conversion incentive (either electric to heat pump or electric to natural gas).
- Incentives shall not exceed 50% of the actual measure cost.
- Verification of efficiencies for space and water heating equipment are according to the Gas Appliance Manufacturers Associations (GAMA) Consumers' Directory of Certified Efficiency Ratings.
- Incentives are paid directly to the homeowner.
- Incentives must be submitted within 90 days of completion of energy efficiency measure.
- Avista reserves the right to inspect energy efficiency measures prior to payment and will coordinate inspection as applicable.
- Allow 6 to 8 weeks for processing and payment of incentive.

ENERGY EFFICIENCY INCENTIVE AGREEMENT

DISCLAIMERS. AVISTA HEREBY DISCLAIMS ANY AND ALL IMPLIED OR EXPRESS WARRANTIES (INCLUDING, BUT NOT LIMITED TO IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE) AND SHALL NOT BE RESPONSIBLE FOR ANY REPRESENTATION OR PROMISE WITH RESPECT TO THE EQUIPMENT MATERIALS OR LABOR REQUIRED FOR THE INSTALLATION OF THE EQUIPMENT ON THE PREMISES, OR THE COST OF SUCH EQUIPMENT, MATERIALS AND LABOR.

Avista is providing funding under this Agreement at the request of the Participant. Because of the variability and uniqueness of individual energy use, it is not possible to predict exact energy savings (if any) that may accrue to any particular participant. Avista, by providing funding, does not warrant that the equipment will achieve any reduction in energy costs to the Participant.

RELEASE. As part of the consideration for this Agreement, participant hereby releases and shall indemnify, hold harmless and defend Avista from any and all claims, losses, harm, costs, liabilities, damages and expenses (including attorneys' fees) of any nature whatsoever arising directly or indirectly out of or in connection with the installation of space-and/or water heating equipment, or weatherization measures at the premises or any material and labor required for such installation.

ENTIRE AGREEMENT/APPLICABILITY/ASSIGNMENT. This Agreement contains the entire agreement between the parties and shall not be modified except by a written instrument signed by the parties. Furthermore, this Agreement shall be binding upon the successors and assigns of the parties. Participants shall not assign this Agreement without the prior written consent of Avista. Avista may freely assign, without limitation, its interest herein.

ATTORNEYS' FEES. If any action is brought to enforce this Agreement, the prevailing party in such action shall be entitled, in addition to any other relief, to a ward of reasonable attorneys' fees and costs incurred in such action.

VERIFICATIONS. Avista shall have the right to verify equipment installed on the Premises. These Residential Energy Efficiency Programs are ongoing as part of Avista's continued commitment to energy efficiency. **The programs are subject to change without notice.**

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AVISTA®

The direct use of natural gas

Energy efficiency is more important than ever. With prices rising all around us, for gasoline, groceries, and so much more, using energy wisely makes good sense.

And while it's true that natural gas prices are trending upward, its many advantages — like consistent hot water, even heat, precise temperature control and more — make it a good energy choice for homeowners and businesses.

Natural gas is also used to generate electricity, and demand for that process across the country is expected to increase significantly, with the continued growth in population and businesses. This puts upward pressure on our costs to serve our customers' electric load, because when we use natural gas to generate electricity, it is less than 50% efficient. That is, when we input 100 BTUs of natural gas into a natural gas-fired generator, less than 50% of the BTUs are converted into useful energy in the form of electricity. The remaining BTUs are exhausted at the end of the process as waste heat. By comparison, when 100 BTUs of natural gas are input into in a high efficiency gas furnace in your home, 90% of the BTUs are converted into useful energy in the form of space heat.

So, despite the upward trend in natural gas prices, the best, most efficient, environmentally friendly use of natural gas is to use it directly in your homes and businesses for space heating, water heating, cooking, and drying clothes.

"While other energy technologies are under development, the direct use of natural gas remains the most efficient and environmentally responsible way to make wise use of our available energy supplies," says Avista's CEO, Scott Morris.

Conservation and energy efficiency measures can also help you manage your energy bill. To identify where to focus your energy efficiency efforts, you can analyze your usage patterns with our online energy audit at www.avistautilities.com.

Once you've determined the energy efficiency efforts that will make a difference in your home, please visit the rebate house at www.everylittlebit.com to learn about the many rebates and incentives to help you conserve energy and improve efficiency.

ENERGY $AVER

Free and easy

This won't cost you a thing.

When the sun's just a little much for you, close your drapes and blinds to keep heat out and air conditioned air in.

Cold weather will be around again, and that's when you want to let the sun in to warm you up.

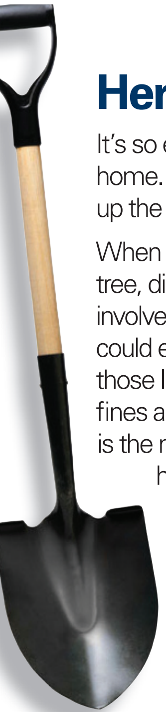
every little bit

Check for more energy saving tips at www.everylittlebit.com

connections

SEPT. 08 connecting you with your hometown utility

Here's the dirt



It's so easy to be safe around your own home. Just put the shovel down and pick up the phone.

When you're sinking a post, planting a tree, digging a ditch, or anything else that involves getting down in the ground, you could easily hit a utility line. Damaging those lines can disrupt service, cost you in fines and repair expenses, or — and this is the most important part — cause you harm.

You can avoid all that in one simple step: Phone the national 811 "Call Before You Dig" number.

That call signals someone to locate and mark the underground lines for you within two working days — for free. And then you'll know what's under your feet and what to watch out for.

We have more information about "Call Before You Dig" and lots more safety tips on our Web site: www.avistautilities.com (key word search: your safety).

Thanks for the assist

Connections readers are one smart bunch!

A couple of months ago, we told you about our efforts to reduce mercury in the environment.

An alert reader sharpened his pencil and noticed we printed a mistake in our story. He kept us on our toes, and we really appreciate it.

Here are the accurate numbers:

Avista began recycling electronic remote transmitters (ERTs) in 1998. Each contains 1.16 grams of mercury, and over the next nine years, we recycled 12,788 ERTs, preventing 32.7 pounds of mercury from reaching the atmosphere.

What's more, Avista disposed of 1,124 cathode ray tube computer monitors — 67,435 pounds' worth — over a five-year period. And when switches in our hydro or substation facilities fail, we replace them with non-mercury switches.

Like you, we strive to do what's best for the environment, and do it right.

One answer is blowing in the wind

Renewable energy: It's on everybody's mind lately. We've been thinking about it too, and so we've acquired the rights to develop a 50-megawatt, $120 million wind farm on 3,200 acres near Reardan, Washington.

Just to put that in context, a single megawatt provides enough energy for 750 homes.

We like the potential wind power represents. We've included wind in our resource mix for several years, and this facility will contribute — on average — 15 megawatts a year. That's less than its 50-megawatt capacity since wind doesn't blow all the time.

There's more wind energy out there, and we're shooting to secure a total of 300 megawatts by 2017. And we're confident we'll get there. We've been developing renewable resources for years.

There's more information about our wind program at www.avistautilities.com (key word search: wind).

Avista cares for our community's seniors…and their caregivers

You might find Avista in some unexpected places.

We serve our community not only by heating your homes and lighting your walkways, but also by extending a helping hand to the more vulnerable members of our community — such as senior citizens.

At the same time, we realize the caregivers of these seniors could use some extra help themselves.

That's why we've teamed up with KHQ.com to form the "Care Giver Resource Center," a wealth of helpful information at your fingertips. We designed the site to answer your questions and introduce you to the many programs and services available to senior citizens in our area.

It addresses such topics as senior housing options, financial affairs, senior life travel, Alzheimer's/dementia, and more.

Simply move your mouse over the KHQ.com "Home" menu at the top left of your screen. Then click on "KHQ Senior Life." to reach the "Senior Life Community Calendar," with details about movie nights, art classes, garden tours, free seminars and other community activities.

On the same page, click the Avista logo to connect to energy-saving tips, information on eligibility for rebates and a list of the many energy assistance programs we offer.

We know that life gets busy and finding the time and resources to care for your loved ones can be a challenge. Let us help so you can enjoy your time together with peace of mind.

connect with us MAILING ADDRESS: 1411 E. Mission, PO Box 3727, Spokane, WA 99220-3727
TOLL-FREE PHONE: (800) 227-9187 | WEB SITE: www.avistautilities.com | E-MAIL: AskAvista@AvistaUtilities.com

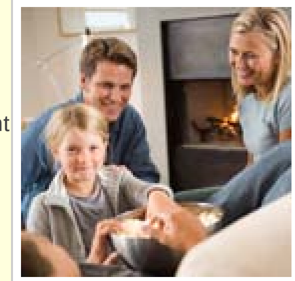
FOR YOUR HOME
- Low Income Assistance
- Ways to Save
- Rebates & Promotions
- PSE's Green Power Program
- Customer Renewable Generation
- Buying a New Home
- Choosing Natural Gas
- Contractor Referral Service
- Electric & Natural Gas Service Requests
- Energy Advisors
- Back-up Generators
- Rates
- Service Guarantees

General Info: 1-888-225-5773

Choosing Natural Gas

How to Switch | Benefits | Heating Systems | Your Feedback

Benefits of natural gas



Choosing natural gas for your home offers valuable benefits, for your budget, the environment, and your comfort.

Energy cost savings

Historically natural gas has cost between 20 percent and 50 percent less than the equivalent amount of electricity, heating oil, or propane. Even with fluctuating energy prices natural gas remains the least expensive and most convenient way to heat homes over electricity, heating oil and propane for furnaces. With space and water heating making up about two-thirds of an average homes' energy usage in the Northwest, you'll see significant savings every month on your bill. When you choose high-efficiency natural gas equipment, the savings are even greater.

Many uses

Natural gas can be used for cooking, space heating, water heating (including on-demand, tankless water heaters), fireplaces, clothes drying, stand-by generators, barbecues, pools, spas, and deck heaters.

Better for the environment

Natural gas is a clean burning fuel – one of the cleanest energy sources available. Harmful air emissions are much less than for heating oil, wood or electricity produced from fossil fuel.

Comfort and convenience

Natural gas delivers comfort! The warm air delivered to your home is about 110 ^{o} F, much warmer than your skin temperature, so your house heats up quickly and feels warm. Heat pumps will deliver air at a temperature lower than your skin temperature and will therefore feel cooler. Natural gas water heaters heat water up twice as fast as electric models, so you receive more hot water sooner.

Reliable and safe

Natural gas is a safe and abundant fuel source. Even during power outages, natural gas cooking ranges, water heaters and fireplaces will continue to work. For safety information about natural gas service and appliances during major power outages and other emergencies, visit our Emergency Preparedness pages under Safety & Reliability on PSE.com

Increased home value

Home buyers routinely ask about natural gas availability when looking for a new home. They want comfort, convenience and lower heating bills that only natural gas can bring. By having natural gas as your home heating fuel you can increase the value of your home.

Rebates

Purchase an ENERGY STAR qualified natural gas furnace, a high efficiency natural gas water heater, or an on-demand, tankless water heater, and receive rebates of $350, $50 and $150 respectively.

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Rebates & Promotions: Converting to Natural Gas

Fuel conversion rebate

- Rebate Description
- Qualifying Rebate Levels & Additional Qualifications

If you're currently heating your home with electricity from PSE, you may be eligible for **up to a $3,950 rebate** to switch your home and water heating source to reliable and affordable natural gas. Click here for more information about qualifying rebate levels and additional qualifications.

An efficient choice

Puget Sound Energy is committed to helping our customers save energy, not only to save money, but to conserve our region's natural resources. You can reduce your energy costs while helping PSE offset the need for securing additional power supplies by converting your electric heating equipment, such as your furnace and water heater, to natural gas.

Benefits of converting to natural gas

In addition to PSE's rebate, you'll also enjoy the many benefits of natural gas:

- Lower energy costs.
- Convenience. Natural gas is delivered to your home directly through underground pipes making it reliable and available to be used in many appliances throughout your home.
- Safety. Natural gas is one of the world's safest sources of energy used by more than 63 million U.S. homes and nearly 750,000 PSE customers.
- Environmental benefits. Natural gas burns cleaner than all other fossil fuels.
- Increased home value. Adding natural gas to your home will pay dividends when you decide it's time to move.

More information about fuel conversion

For more information and to learn if you qualify for the fuel conversion rebate, call a PSE Energy Advisor at 1.800.562.1482, Monday through Friday, 8 a.m. to 5 p.m.

Read more about PSE's fuel conversion rebate and download an application. (560 KB PDF)

For more information about the benefits of choosing natural gas, visit the Choosing Natural Gas section of the PSE Web site.

Request a referral

Use PSE's Contractor Referral Service for a free, no obligation referral to a contractor in your area.

Get ADOBE® READER®

To view and print the PDF-formatted documents linked on this page, you'll need the Adobe ® Acrobat ® Reader. Download a free reader now.

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FOR YOUR HOME
- Low Income Assistance
- Ways to Save
- Rebates & Promotions
  - Overview
  - Appliances
  - Lighting
  - Heating
  - Converting to Natural Gas
  - Insulation
  - Insulation Referrals
  - Water Heating
  - Showerhead Kit
  - Windows
  - Manufactured Homes
- PSE's Green Power Program
- Customer Renewable Generation
- Buying a New Home
- Choosing Natural Gas
- Contractor Referral Service
- Electric & Natural Gas Service Requests
- Energy Advisors
- Back-up Generators
- Rates
- Service Guarantees

General Info: 1-888-225-5773

Rebates & Promotions: Converting to Natural Gas

- Rebate Description
- Qualifying Rebate Levels & Additional Qualifications

Qualifying rebate levels and additional qualifications

If you're currently heating your home with electricity from PSE, you may be eligible for **up to a $3,950 rebate** to switch your home and water heating source to reliable and affordable natural gas.

In addition to the fuel conversion rebate, PSE offers rebates on ENERGY STAR® qualified natural gas equipment to make the switch to natural gas even more affordable. Potential rebate amounts:

PSE fuel conversion rebate tables*

Type of heating	Conversion rebate
Home and water	$1,950 - $3,950
Home only	$500 - $2,500
Water only	$950

** Rebate amount is dependent on current type of home and/or water heating, annual electricity usage and type of heating equipment installed. Rebate amount is limited to 75 percent of total equipment and installation cost.*

PSE equipment rebate levels**

Type of equipment	Equipment rebate
ENERGY STAR® qualified furnace	$350
ENERGY STAR® qualified water heater	$50
ENERGY STAR® qualified tankless water heater	$150

***Other natural gas providers may offer different equipment rebates.*

Additional Qualifications

- Conversion must be completed within an existing single-family residence of four units or less. Manufactured, modular and mobile homes are not eligible.
- Applicant must be a PSE electric customer currently using electricity as a primary source of home and/or water heating.
- Rebate is subject to the current minimum annual electric usage requirements, as determined by PSE.
- Applicant must install ENERGY STAR® qualified natural gas home and/or water heating equipment (fireplaces are not eligible).
- Applicant is ineligible for home heating rebate if a hybrid system and/or heat pump is installed in conjunction with natural gas equipment or if existing heat pump remains on the premises.
- Applicant is responsible for complying with all applicable codes and regulations.
- Applicant must have ordered natural gas service and have an invoice dated after Jan. 30, 2009.
- Rebate form must be submitted within 90 days of fuel and equipment conversion.
- Other requirements may apply.

More information about fuel conversion

For more information and to learn if you qualify for the fuel conversion rebate, call a PSE Energy Advisor at 1.800.562.1482, Monday through Friday, 8 a.m. to 5 p.m.

For more information about the benefits of choosing natural gas, visit the Choosing Natural Gas section of the PSE Web site.

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An efficient choice

Puget Sound Energy is committed to helping our customers save energy, not only to save money, but to conserve our region's natural resources. You can reduce your energy costs while helping PSE offset the need for securing additional power supplies by converting your electric heating equipment, such as your furnace and water heater, to natural gas.

Benefits of converting to natural gas

In addition to PSE's rebate, you'll also enjoy the many benefits of natural gas:

- Lower energy costs.
- Convenience. Natural gas is delivered to your home directly through underground pipes making it reliable and available to be used in many appliances throughout your home.
- Safety. Natural gas is one of the world's safest sources of energy used by more than 63 million U.S. homes and nearly 750,000 PSE customers.
- Environmental benefits. Natural gas burns cleaner than all other fossil fuels.
- Increased home value. Adding natural gas to your home will pay dividends when you decide it's time to move.

Need a contractor?

PSE's Contractor Referral Service makes it easy to find a pre-screened, independent contractor for nearly any product replacement or home-improvement project.

For a free, no obligation referral to a contractor in your area, visit PSE.com or call a PSE Energy Advisor at 1.800.562.1482, Monday - Friday, 8 a.m. - 5 p.m.

Qualifications

- Conversion must be completed within an existing single-family residence of four units or less. Manufactured, modular and mobile homes are not eligible.
- Applicant must be a PSE electric customer currently using electricity as a primary source of home and/or water heating.
- Rebate is subject to the current minimum annual electric usage requirements, as determined by PSE.
- Applicant must install ENERGY STAR qualified natural gas home and/or water heating equipment (fireplaces are not eligible).
- Applicant is ineligible for home heating rebate if a hybrid system and/or heat pump is installed in conjunction with natural gas equipment or if existing heat pump remains on the premises.
- Applicant is responsible for complying with all applicable codes and regulations.
- Applicant must have ordered natural gas service and have an invoice dated after Jan. 30, 2009.
- Rebate form must be submitted within 90 days of fuel and equipment conversion.
- Other requirements may apply.

Converting to natural gas

PUGET SOUND ENERGY
The Energy To Do Great Things

3371 2/09

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PSE's fuel conversion rebate

If you're currently heating your home with electricity from PSE, you may be eligible for up to a **$3,950** rebate to switch your home and water heating source to reliable and affordable natural gas.

Qualifying rebate levels

In addition to the fuel conversion rebate, PSE offers rebates on ENERGY STAR® qualified natural gas equipment to make the switch to natural gas even more affordable. Here are the potential rebate amounts:

PSE fuel conversion rebate levels*

Type of heating	Conversion rebate
Home and water	$1,950 - $3,950
Home only	$500 - $2,500
Water only	$950

* Rebate amount is dependent on current type of home and/or water heating, annual electricity usage and type of heating equipment installed. Rebate amount is limited to 75 percent of total equipment and installation cost.

PSE equipment rebate levels**

Type of equipment	Equipment rebate
ENERGY STAR qualified furnace	$350
ENERGY STAR qualified water heater	$50
ENERGY STAR qualified tankless water heater	$150

**Other natural gas providers may offer different equipment rebates.

For more information and to learn if you qualify for the fuel conversion rebate, call a PSE Energy Advisor at 1.800.562.1482, Monday - Friday, 8 a.m. - 5 p.m.

PSE PUGET SOUND ENERGY
The Energy To Do Great Things

Fuel conversion rebate application

For more information or for help completing this form, please call a PSE Energy Advisor at 1.800.562.1482.

Directions:
Carefully fill out this application and include a copy of your sales receipt or invoice. *Please keep a copy for your records.*

Mail to:
Puget Sound Energy, Fuel Conversion Rebate Program, PO BOX 97034, EST-10W, Bellevue, WA 98009-9734

Fax to: 425.456.2195

PSE ELECTRIC ACCOUNT NUMBER (10 DIGITS)

NAME OF PERSON THE REBATE CHECK SHOULD BE MADE PAYABLE TO | DAYTIME PHONE

FULL INSTALLATION ADDRESS | CITY | STATE | ZIP

MAILING ADDRESS (IF DIFFERENT)

E-MAIL ADDRESS

☐ Yes, sign me up for PSE's free *Energy at Home* e-newsletter.

Number of years in your current home?____________

Current type of heating: ☐ Baseboard ☐ Forced air **Referral number:**____________

Type of conversion: ☐ Home and water heating ☐ Home heating only ☐ Water heating only

☐ **Yes, I have also filled out the "Heating and Water Heating" rebate form for high-efficiency equipment (available at PSE.com)**

PSE will review your rebate application and determine if your natural gas conversion project qualifies for the rebate. Rebate amount is paid directly to the customer. Rebate is limited to one per customer dwelling. Please allow six to eight weeks to receive your rebate check.

By signing below I represent that I have read, understood and agreed to the terms and conditions of this service and all the information on this form is true. I also agree to random inspections for program compliance by a PSE representative.

Further, I acknowledge that my existing primary heating system, either home and/or water, was electric and was replaced with a natural gas system at the location indicated. PSE has made no implied or expressed warranties or representation with regard to this conversion or energy savings from its completion. This is a tariffed service and is subject to change or termination without prior notice.

SIGNATURE ____________________

DATE ____/____/____

What other types of natural gas appliances do you plan on purchasing?

☐ Range ☐ Fireplace
☐ Clothes dryer ☐ Other__________ (Please explain)
☐ Barbecue

For Puget Sound Energy use only

COMMENTS

DATE: ____/____/____ APPROVED ☐ Yes ☐ No

TOTAL AMOUNT REBATED: $__________

Attachment 26.1

TGI Lower Mainland Typical Annual Bills

	2009	2010	2011	2012	2013
Rate Schedule 1 (Residential) Customers					
Typical Annual Usage	**95**	**95**	**95**	**95**	**95**
Basic Charge per month	$11.84	$11.84	$11.84	$11.84	$11.84
Delivery Charge per GJ	$2.795	$2.795	$2.795	$2.795	$2.795
Midstream Charge per GJ	$1.015	$1.015	$1.015	$1.015	$1.015
Cost of Gas per GJ	$5.962	$5.962	$5.962	$5.962	$5.962
TGI Total Annual Bill	**$1,070**	**$1,070**	**$1,070**	**$1,070**	**$1,070**
Carbon Tax per GJ	**$0.7449**	**$0.9949**	**$1.2449**	**$1.4949**	**$1.7449**
Annual Carbon Tax Amount	**$71**	**$95**	**$118**	**$142**	**$166**
Total Annual Bill Inclusive of Carbon Tax	***$1,141***	***$1,165***	***$1,189***	***$1,212***	***$1,236***
Annual Bill Increases Due to Carbon Tax					
Annual Bill Increase per Year		**$24**	**$24**	**$24**	**$24**
Annual Percentage Increase		**2.08%**	**2.04%**	**2.00%**	**1.96%**

	2009	2010	2011	2012	2013
Rate Schedule 3 (Commercial) Customers					
Typical Annual Usage	**2,800**	**2,800**	**2,800**	**2,800**	**2,800**
Basic Charge per month	$132.52	$132.52	$132.52	$132.52	$132.52
Delivery Charge per GJ	$2.037	$2.037	$2.037	$2.037	$2.037
Midstream Charge per GJ	$0.809	$0.809	$0.809	$0.809	$0.809
Cost of Gas per GJ	$5.962	$5.962	$5.962	$5.962	$5.962
TGI Total Annual Bill	**$26,253**	**$26,253**	**$26,253**	**$26,253**	**$26,253**
Carbon Tax per GJ	**$0.7449**	**$0.9949**	**$1.2449**	**$1.4949**	**$1.7449**
Annual Carbon Tax Amount	**$2,086**	**$2,786**	**$3,486**	**$4,186**	**$4,886**
Total Annual Bill Inclusive of Carbon Tax	***$28,338***	***$29,038***	***$29,738***	***$30,438***	***$31,138***
Annual Bill Increases Due to Carbon Tax					
Annual Bill Increase per Year		**$700**	**$700**	**$700**	**$700**
Annual Percentage Increase		**2.47%**	**2.41%**	**2.35%**	**2.30%**

	2009	2010	2011	2012	2013
Rate Schedule 5 (Industrial) Customers					
Typical Annual Usage	**9,700**	**9,700**	**9,700**	**9,700**	**9,700**
Basic Charge per month	$587.00	$587.00	$587.00	$587.00	$587.00
Delivery Charge per GJ	$0.515	$0.515	$0.515	$0.515	$0.515
Demand Charge per GJ per Month	$14.655	$14.655	$14.655	$14.655	$14.655
Cost of Gas per GJ	$6.632	$6.632	$6.632	$6.632	$6.632
TGI Total Annual Bill	**$86,324**	**$86,324**	**$86,324**	**$86,324**	**$86,324**
Carbon Tax per GJ	**$0.7449**	**$0.9949**	**$1.2449**	**$1.4949**	**$1.7449**
Annual Carbon Tax Amount	**$7,226**	**$9,651**	**$12,076**	**$14,501**	**$16,926**
Total Annual Bill Inclusive of Carbon Tax	***$93,549***	***$95,974***	***$98,399***	***$100,824***	***$103,249***
Annual Bill Increases Due to Carbon Tax					
Annual Bill Increase per Year		**$2,425**	**$2,425**	**$2,425**	**$2,425**
Annual Percentage Increase		**2.59%**	**2.53%**	**2.46%**	**2.41%**

All rates are as at July 1st of each year, inclusive of applicable rate riders, and exclusive of any applicable taxes (except the Carbon Tax).
All delivery and commodity rates are held constant at current rates as at July 2009.

Attachment 31.2

Directive 17, 2006 IEP/LTAP
Long Term Rate Increase Forecast

1. Introduction

This report is BC Hydro's compliance with directive 17 from the British Columbia Utilities Commission (BCUC) decision on BC Hydro's 2006 Integrated Electricity Plan and Long Term Acquisition Plan (2006 IEP/LTAP)[1].

The directive states:

> **"…the Commission Panel directs BC Hydro to file a report containing, among other things, a financial forecast of BC Hydro's rates in both real and nominal terms, for a minimum of ten years, but preferably 20 years. Input assumptions should be summarized in a concise, but comprehensive manner."**

The decision (as amended via an errata to the decision, in the BCUC letter of June 1, 2007) goes on to direct:

> **"The Commission Panel further directs BC Hydro to rely on the report for assumptions regarding retail prices in each of the CPR, the load forecast, and DSM evaluation methodologies. Furthermore, the report should identify and explain linkages, if any, of the impact of real electricity prices in the CPR, the load forecast and BC Hydro's DSM evaluation methodologies."**

The forecasting of BC Hydro's electricity rates over an extended period of time (10 to 20 years) requires a significant number of input assumptions with respect to a wide range of variables:

- external forecasts, such as interest rates, inflation rates, and exchange rates;

[1] *In the Matter of British Columbia Hydro and Power Authority's 2006 Integrated Electricity Plan and 2006 Long-term Acquisition Plan,* Decision, May 11, 2007, page 154.

- timing and magnitude of capital programs and projects, and demand-side management (DSM) expenditures (and energy savings);

- other revenue requirement inputs (for example, the different elements of the cost of energy, operating costs, amortization rates, trade income, deferral account transfers and recoveries).

All of these inputs need to be internally consistent. The forecasting exercise is not a trivial task and necessitates many simplifications.

In addition, any such forecast also relies on making assumptions regarding any changes in government policy and changes in legislation and regulations, including, for example, special directions regarding BC Hydro's capital structure for rate setting purposes.

Because of the above, BC Hydro is of the view that a long term rate increase forecast is highly uncertain and is subject to significant variability depending on the assumptions made. In particular, a rate increase forecast beyond a 10 year period relies on so many uncertain assumptions, and in theory could come about from many possible future scenarios, that, in BC Hydro's view, to attempt to make a specific forecast for that period is of little or no value. For that reason BC Hydro chooses to assume nominal rate increases at the rate of inflation (i.e., real rate increases of zero) for the second ten years of the twenty year forecast.

Further, the first ten years of the long term rate increase forecast presented in this report are based on a large number of assumptions and as such must be treated as indicative only, produced solely for the purpose of informing the load forecast and DSM analysis, as required by the BCUC directive. The forecast does not represent BC Hydro's view as to its future revenue requirements applications beyond F2010. Any rate increases requested in those applications will be based on BC Hydro's detailed assessment of its expected revenues and costs at the time of filing, taking into account the operating conditions and plans forecast for the relevant test period.

Section 2 of this report summarises the financial forecast overview and the input assumptions used to develop the forecast. Section 3 of this report provides the rate increase forecast in both nominal and real terms. Section 4 describes how the long term rate increase forecast relates to the 2008 DSM Plan, the 2007 Load Forecast and the 2007 Conservation Potential Review (CPR), and shows the variance from the January 2008 long term rate increase forecast.

2. Forecast Overview and Assumptions

2.1 Forecast Overview

The financial forecast uses F2008 rates, including the deferral account rate rider, as the reference rate, or starting point. The forecast has been developed using a variety of inputs including forecast revenues, operating expenses, capital expenditures, debt balances, and economic variables over a 10 year forecast period (F2009 to F2018). The forecast reflects the Base Resource Plan (BRP) shown in Appendix O to the 2008 LTAP (Exhibit B-1-1). The inputs are used to estimate the incremental revenue required to achieve an assumed return on equity each year during the 10 year period. This incremental revenue can be presented in real or nominal terms, and is an indicative estimate of across-the-board rate increases that the assumptions and inputs would give rise to.

Note that for consistency, the forecast rate increases for the first two years of the financial forecast are based on the revenue requirements included in BC Hydro's Evidentiary Update filing in its F2009/F2010 Revenue Requirements Application (F09/F10 RRA) (Exhibit B-10 in that proceeding). In addition, they take account of the change in the deferral account rate rider from year to year, using BC Hydro's proposed rate rider mechanism, as per the F09/F10 RRA.

2.2 Inputs and Assumptions

The inputs and assumptions used in the financial forecast are described below.

Economic Variables – Forecasts of economic variables provided by the B.C. Ministry of Finance for the period F2009 to F2013 are used as inputs into the financial forecast. These are also consistent with the economic variables in the forecast in the Evidentiary Update to the F09/F10 RRA. Table 1 below summarises the assumptions. For the F2014 to F2018 forecast period, the forecasts for F2013 are assumed.

Table 1 Economic Variables

Economic Variables	F2009	F2010	F2011	F2012	F2013	F2014-F2018
Inflation (BC CPI) (%)	2.1	2.1	2.1	2.1	2.1	2.1
Short Term Interest Rate (%)	4.30	4.78	5.25	5.25	5.25	5.25
Long Term Interest Rate (%)	5.04	5.59	6.33	6.70	6.70	6.70
Exchange Rate C$/U.S.$	1.01	1.05	1.07	1.07	1.07	1.07

Capital Structure – By Orders in Council No. 27 and 28 (January 17, 2008), the B.C. Government amended the definition of BC Hydro's equity included in Special Directive HC1 and Special Direction HC2. The forecast assumes the new definition of equity as set out in HC1 and HC2, and the forecast also assumes that dividend payments to the Province must not result in a greater than 80:20 debt to book equity ratio, to be consistent with Special Directive HC1.

Return on Equity – Consistent with the F09/F10 RRA, the forecast assumes a return on equity for BC Hydro of 11.78 per cent, and applies that throughout the F2009 to F2018 forecast period. The forecast assumes a deemed equity for ratemaking purposes equalling 30 per cent of the sum of BC Hydro's average debt and average equity balances for the year, to be consistent with the amended Special Direction HC2.

Load Forecast – For the F2009 to F2018 period, the forecast assumes the 2007 Load Forecast, which was provided in the 2008 LTAP, with the exception that for the F2009 to F2010 period, the forecast assumes updated load forecast volumes as presented in the F09/F10 RRA Evidentiary Update.

DSM (Energy Savings and Expenditures) – The financial forecast assumes DSM energy savings that are consistent with the DSM Option A– Mid scenario (included as part of the 2008 LTAP BRP) throughout the F2009 to F2018 forecast period.

The forecast assumes:

- DSM expenditures that are consistent with the DSM Plan costs included in the 2008 LTAP; and

- DSM expenditures will continue to be subject to regulatory deferral treatment, and are amortized over a ten-year period.

Domestic Revenue – The forecast calculates domestic sales volumes based on the 2007 Load Forecast and DSM energy savings described above. F2008 rates by customer class (including the deferral account rate rider) are applied to forecast domestic sales volumes to determine forecast total domestic revenue before rate increases, on an annual basis, for the F2009 to F2018 forecast period.

Trade Income – Trade Income is the net income of Powerex Corp., adjusted for rate-setting purposes to be no more than $200 million and no less than $0. The forecast assumes net trade income for F2009 and F2010 as per the Evidentiary Update. For F2011 to F2013, trade income is assumed to increase to $199 million by F2013. For F2014 to F2018, trade income is assumed to be $200 million annually.

Energy Costs – For F2009 and F2010, the forecast assumes the cost of energy forecast as per the Evidentiary Update. These costs, and estimated F2011 energy costs, are based on the resource operating decision process documented in the F09/F10 RRA at section 3.2 “System Optimization Overview”.

For the F2012 to F2018 forecast period, the forecast assumes cost of energy, on an annual basis, based upon the BRP shown in Appendix O of the 2008 LTAP.

Water Rental Costs – For F2009 and F2010, the forecast assumes the water rental costs as per the Evidentiary Update. For this period, as well as for the F2011 to F2018 forecast period, the forecast assumes water rental rates as of January 1, 2008 are applied to forecasted hydroelectric generating capacity and forecasted generation output on an annual basis to estimate water rentals. Additionally, the forecast assumes that water rental rates are indexed to BC Hydro's rate increases from F2009 to F2018, as per the existing indexation mechanism.

Operating Costs – For F2009 and F2010, the forecast assumes operating costs as per the Evidentiary Update. From F2011 operating costs, excluding those subject to regulatory treatment, are assumed to increase by inflation.

Taxes – Taxes include school taxes and grants in lieu of general taxes. For F2009 and F2010, the forecast assumes school taxes and grant amounts as per the Evidentiary Update. From F2011 to F2018 school taxes, generation facility grants, and general grants are assumed to increase by inflation. Revenue grants are based on one per cent of forecast domestic revenue from F2011 to F2018.

Capital Expenditures – The forecast includes estimated capital expenditures by major plant type, developed for this forecasting exercise. These are high level estimates only, and actual capital plans and projects over the ten year period will depend on many variables. For the F2009 to F2010 forecast period, the forecast assumes capital expenditure and additions as per the Evidentiary Update. Transmission capital expenditures estimates for F2009 to F2018 are consistent with the "BCTC - Transmission System Capital Plan F2009 to F2018", as submitted to the BCUC on December 21, 2007.

Amortization – The forecast assumes property, plant and equipment in service are amortized over the expected useful lives of the assets using the straight-line method. All depreciation rates used are the same as those used in the F09/F10 RRA.

Finance Charges - Finance charges represent the cost of BC Hydro's debt portfolio, and mainly comprise of interest charges on BC Hydro debt. The forecast assumes interest costs on existing debt are based on actual interest rates at the time the debt was issued. Interest costs on future debt are based on forecast debt issues at forecast interest rates. BC Hydro has used interest rate forecasts provided by the B.C. Ministry of Finance for F2009 to F2013 (see Table 1).

Deferral Accounts – The forecast assumes the ongoing treatment of the Deferral Accounts and other regulatory accounts as either previously approved by the BCUC or as proposed by BC Hydro in the F09/F10 RRA, including the deferral account rate rider mechanism.

3. Forecast Rate Increases

As noted in section 1 above, the forecast increases provided below are indicative only, rely on a large number of assumptions, and have been produced solely for the purpose of informing the load forecast and the DSM analysis.

The rate increase forecast from F2009 uses F2008 rates, including the deferral account rate rider, as the reference or starting point. For the first two years of the forecast the rate increases are based on those applied for in BC Hydro's F09/F10 RRA Evidentiary Update, and also include the changes in the rate rider. Accordingly the rate increases for F2009 and F2010 are 4 per cent and 9 per cent respectively in nominal terms (2 per cent and 6 per cent respectively, in real terms).

For the following eight years the forecast of annual rate increases in real terms are estimated to be as follows: for F2011, 7 per cent; for F2012 through F2014, 4 per cent; for F2015 and F2016, 6 per cent; for F2017, 3 per cent; and for F2018, 1 per cent. Nominal rate increases for each year would be around 2 per cent higher, based on the forecast of inflation. As noted previously, for the F2019 to F2028 period, rates are assumed to rise at the rate of inflation (B.C. Consumer Price Index (CPI)), forecast at 2.1 per cent per year.

4. Use of Forecast Output

For the purpose of determining the 2007 Load Forecast and the energy savings and lost revenue associated with the 2008 DSM Plan, BC Hydro has incorporated the effects of indicative rate increases as estimated in the long term rate increase forecast.

4.1 Demand Side Management Analysis

Given the timing of preparing the 2008 DSM plan, a January 2008 version of the long term rate increase forecast was used in the estimation of lost revenues associated with that plan. Lost revenues are an input to the Non-Participant test. The January 2008 forecast was also used in the estimation of energy savings from assumed new stepped rate structures in the 2008 DSM Plan, by informing the specific pricing levels within the modelled rate structures.

4.2 2007 Load Forecast

A January 2008 version of the long term rate increase forecast was also used as an input to the 2007 Load Forecast presented in the 2008 LTAP. The rate increase forecasts impact the after-DSM load forecast in two ways, and these impacts are determined separately. Firstly, the assumed across-the-board rate increases under current rate structures produce a demand response (given an assumed price elasticity), and reduce the before-DSM load forecast. Secondly, assumed new stepped rate structures (with prices based on the forecast rate increases), produce a demand response (given assumed price elasticity). These rate structure-induced energy savings are considered to be part of DSM savings and are subtracted to produce the after-DSM load forecast.

4.3 2007 Conservation Potential Review (CPR)

A long term rate increase forecast was not available in time for the 2007 CPR. The BCUC, in its decision concerning the 2006 IEP/LTAP at page 154, recognized that the financial forecast may not be available in time for the 2007 CPR, and also noted that the financial forecast "was not an item in the terms of reference" for the 2007 CPR. The 2007 CPR referenced the 2006 Load Forecast. In the 2006 Load Forecast rates were assumed to increase in nominal terms at the rate of inflation. This is the same assumption used in the 2007 CPR.

4.4 Current Forecast Compared to January 2008 Rate Increase Forecast

The January 2008 long term rate increase forecast was prepared and used for load forecasting and DSM analysis purposes, in the development of BC Hydro's 2008 LTAP[2]. Since that time, updates have been made to the forecast inputs and assumptions including: (1) updated capital expenditure estimates; (2) updated energy cost estimates related to an updated energy portfolio from the 2008 LTAP; (3) new deemed equity definition; (4) updated water rental rates, and; (5) inclusion of the deferral account rate rider in calculating annual rate increases.

[2] The forecast was filed as an undertaking in BC Hydro's Residential Inclining Block Rate proceeding (Undertaking No. 7, Exhibit B-28).

The difference between the current long term rate increase forecast and the January 2008 long term rate increase forecast is shown in Table 2. The variations between the two forecasts illustrate generally the sensitivity of rate increase forecasting to the inputs and assumptions, and demonstrate why such a forecast must be viewed as indicative only.

Table 2 Variance from January 2008 forecast

	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019-F2028
Increase (decrease)	(2)%	0%	2%	(3)%	6%	6%	4%	2%	1%	2%	0%

BC Hydro, as a result of the variance between the current long term rate increase forecast and the January 2008 forecast, analysed the effect of this current forecast on the load forecast.

The analysis suggests that the current long term rate increase forecast results in additional rate structure-induced energy savings averaging approximately 600 GWh per year from F2017 through F2028 (approximately 1 per cent of the forecast load after DSM in F2017). After integration with other DSM initiatives, net incremental savings would likely be lower since some of the additional rate structure-induced savings would displace savings from DSM programs.

The analysis also suggests that the current long term rate increase forecast reduces the forecast load before DSM by an additional approximate average of 600 GWh per year from F2017 through F2028.

BC Hydro does not intend to update the 2007 Load Forecast to reflect these changes as there are other uncertainties and developments that have occurred since the forecast was produced that would also need to be reflected.

Attachment 31.3.1

Attachment 33.3

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 39.1

Terasen

Search

News
Leadership team
Investor centre
› Annual report
The environment
Community relations
History
Contact us

Annual report

Letter from R.L. (Randy) Jespersen, President & CEO

From the first natural gas service, to the pursuit of delivering alternative energy solutions today, Terasen and its predecessor companies have always been innovative - with a vision for British Columbia's future. With this in mind, the theme for the 2008 Terasen Inc. Annual Report is *Delivering BC's energy future*.

For Terasen, 2008 was an exceptional year. I invite you to use this report as a guide to our overall performance.

We produced balanced business results, invested more than $213 million in BC, and improved our customer satisfaction rating for the fifth year in a row.

As leaders in energy efficiency and conservation, Terasen is well positioned to help meet BC's climate action targets. In 2008, we helped customers save more than 610,000 gigajoules of natural gas, the equivalent of heating over 6,400 homes.

As an emerging leader in alternative energy solutions, Terasen led the way with one of the first biogas capture projects in the province and continues to develop geothermal projects and district energy systems - initiatives that support BC's Energy Plan. Such endeavours show our leadership in developing uses for clean, renewable energy.

Participating in the growth and well-being of the cities and towns we serve is important for us at Terasen. We work hard to demonstrate this in what we do every day - from expanding BC's energy infrastructure to the many volunteer efforts of our employees.

Committed to safety and excellence, Terasen serves more than 931,000 customers in over 125 BC communities. Going forward, we will continue to build on our successes, and create value for our customers, Fortis Inc. and BC communities, while being a great place to work.

» 2008 annual report (PDF 2.4 MB)

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Terasen

Delivering BC's energy future

Annual Report 2008

About Terasen

Terasen Inc., a Canadian corporation headquartered in Vancouver, British Columbia, is the parent company of the regulated Terasen Gas companies and Terasen Energy Services Inc. Together they serve more than 931,000 customers in over 125 BC communities. British Columbians trust Terasen to deliver energy safely and reliably.

A wholly owned subsidiary of Fortis Inc., Terasen, together with its subsidiaries, is one of the largest distributors of natural gas in the greater Pacific Northwest and a leading provider of alternative energy systems. It serves more than 95 per cent of BC's natural gas customers and delivers more than 20 per cent of the Province's energy needs.

In 2008, Terasen invested more than $213 million in British Columbia.

Terasen Gas safely and reliably delivers the natural gas and propane that warms people's homes, cooks their dinners, heats their water and helps run their businesses. Three companies make up the Terasen Gas group: Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.

Terasen Energy Services Inc. provides both regulated and non-regulated alternative energy, delivered through integrated energy systems, to multi-family developments, larger commercial buildings and resorts. This includes geothermal, solar and other renewable energy forms combined with conventional fuels such as natural gas, propane and electricity. The operations of these integrated energy systems are managed through a shared services contractual arrangement with Terasen Gas.

Solutions for today and tomorrow

Terasen maintains a strong focus on operational excellence including environmentally sound practices. As a leader in BC's energy mix, the company plays a foundational role in the economic, environmental and energy framework of the Province.

Terasen is committed to successfully meeting BC's climate action challenges. Well managed with a solid reputation among regulators, First Nations, municipalities and employees, Terasen works with customers and communities providing energy solutions to help them meet their economic and environmental goals.

By providing innovative solutions, the company is adapting to the Province's changing energy needs. Respected and trusted, Terasen's integrated approach to piped energy solutions is delivering BC's energy future.

Contents

Our performance

A year of solid results

Terasen is a healthy, growing company and a leading provider of piped energy and related infrastructure. A well-managed company with solid earnings, it is efficient, productive and innovative in meeting customers' energy needs.

Terasen lives its commitment to the environment and the communities it serves. In 2008, the company ensured the public's ongoing trust, delivered stable rates, maintained its safety record, and increased customer connections.

Adapting well to the Province's changing energy mix, Terasen is a solution provider with a vision for BC's energy future.

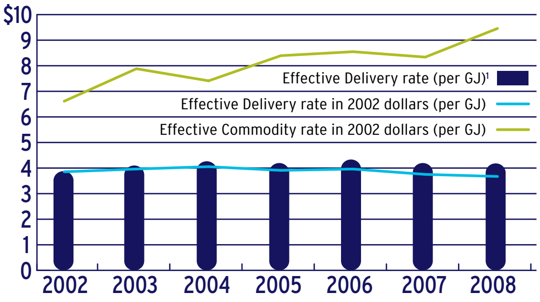
Terasen Gas highlights

Financial[1]	2008	2007	2006
Net earnings *In millions of dollars*	$ 118.9	$ 111.7	$ (651.1)
Gross revenues *In millions of dollars*	$1,905.2	$1,750.8	$1,739.2
Operating expenses *In millions of dollars*	$ 199.3	$ 192.0	$ 189.5
Capital programs before contributions *In millions of dollars*	$ 227.9	$ 178.2	$ 161.5
O&M per customer	$ 229.15	$ 224.27	$ 231.41
Performance[2]	**2008**	**2007**	**2006**
Overall customer satisfaction rating	79.7%	79.3%	77.7%
Emergency response time[3] *In minutes:seconds from dispatch to site*	20:42	20:36	21:30

1 Consolidated results of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.
2 Terasen Gas Inc.
3 The 2008 target for this measure was less than 21:06.

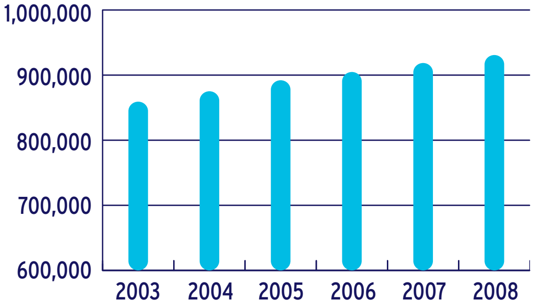
Commodity and delivery rates

In Lower Mainland



1 GJ refers to gigjoule

Terasen Gas customers[1]



1 Consolidated results of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.

Letter to Shareholder

When the Government of BC put forth its bold vision for the Province's environment, economy and energy framework, it essentially set new challenges for many, including Terasen.

We believe policy makers showed wisdom by recognizing that meaningful reductions in greenhouse gas emissions must come from both the industrial and consuming sectors. Given that Terasen delivers more than 20 per cent of the energy consumed in BC, an amount comparable to the total electricity consumed, we are expected to find and facilitate energy solutions to help meet the Province's climate action targets.

Uniquely positioned as a trusted, reliable service provider, we are promoting the efficient direct application of natural gas and expanding integrated energy solutions. Piped energy, whether natural gas, propane or alternative renewable energies, will be a foundation on which a sustainable energy system will be built over the long term. Interacting with BC's existing power grid, the two will be mutually supportive and deliver energy services at efficiency levels vastly higher than we see today.

By building on our core competencies and carefully executing our strategic plan, we are pursuing new, environmentally responsible opportunities.

Innovative leaders

Last year, Terasen became one of the first utilities in North America to explore the potential of biogas. Our project with a West Vancouver wastewater treatment facility will capture biogas and inject it into our existing delivery system. The pilot is the first of its kind in the Province.

With our Request for Expressions of Interest for biogas production we will pursue methane recovery opportunities from landfills, waste treatment and agriculture facilities. Such innovative partnerships reflect our leadership in capturing and developing practical uses for clean, economic, renewable energy.

We expanded our reach into commercial and multi-family housing markets, while pursuing technologies such as thermal and individual gas metering. We worked with FortisBC and BC Hydro on energy efficiency and conservation initiatives.

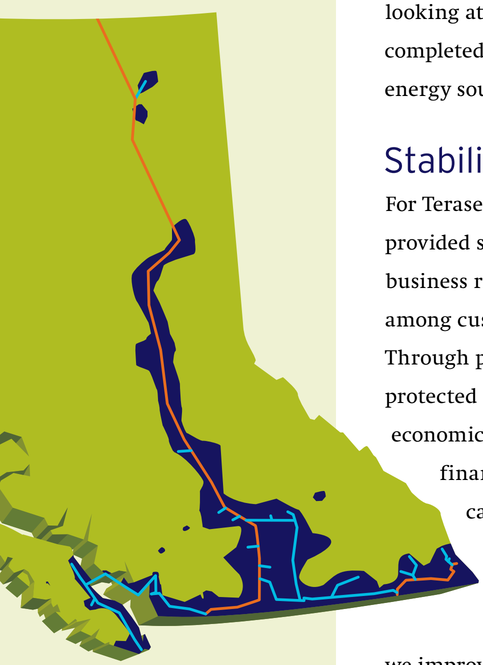
Responsible stewards

Since 1995, Terasen has continued to reduce greenhouse gas emissions from our operations. In fact, our mainland utility's average annual emissions aligned with Canada's Kyoto obligations from 2000 through the latest reporting period. We also remained vigilant in maintaining our environmental management practices, protecting the land, air and waters of BC.

Area of operations

Ever mindful of the environmental impacts business and industry produce, we introduced a compressed natural gas vehicle program for the transportation sector. We also submitted an Energy Efficiency and Conservation Application, which is before the BC Utilities Commission. It is designed to help customers conserve energy, reduce emissions and improve the affordability of natural gas service.

As BC's emerging leader in alternative energy systems, we worked on a variety of projects and signed a number of agreements in 2008. These projects reflect how we can use our resources more efficiently—by looking at energy as an integrated system. Once completed, these projects will harness renewable energy sources, and ensure clean energy delivery.



Stability and growth

For Terasen, 2008 was an exceptional year. We provided safe, reliable service, produced balanced business results, and maintained a solid reputation among customers, regulators and local governments. Through prudent financial management we protected customer interests. Despite challenging economic times and volatile capital markets, our financial performance maintained access to capital important for our operations.

Our strong commitment to operational excellence remained focused. In fact, we improved our customer satisfaction record for the fifth year in a row. We invested more than $213 million in BC, connected 18,360 new homes and businesses to our system, and held our delivery rates essentially flat for five consecutive years. We helped our customers save more than 612,500 gigajoules of natural gas, the equivalent of heating more than 6,400 homes. We also hired more than 190 new employees. As a result, Terasen is well positioned to contribute to Fortis' focused growth. We will continue to invest in the future, creating value for our customers, the communities we serve, employees and our shareholder.

Continued excellence

Going forward, we will capitalize on value-added growth opportunities, including the development and execution of sound environmental and energy regulatory policy. We will remain focused on operational excellence and continue to retain and invest in our talented employees.

Fulfilling a key element in Whistler's Sustainable Energy Plan, we will complete the Whistler pipeline and convert the community's propane system to natural gas. Our energy infrastructure will expand with the continuing construction of the Mt. Hayes natural gas storage facility on Vancouver Island.

We will also implement technology improvements, continue our focus on system integrity management, expand customer service offerings and contribute to Vancouver and Whistler's 2010 Olympic security preparedness. With our corporate performance and reliable service, we have proven ourselves a leader in serving the diverse energy needs of British Columbians.

Expectations around the economy, energy and the environment will continue to evolve. Be assured, Terasen is delivering BC's energy future.

H. Stanley Marshall
President and CEO,
Fortis Inc.
Chair, Board of Directors
Terasen Inc.

R.L. (Randy) Jespersen
President and CEO
Terasen Inc.

Engaging our stakeholders

Whether as an educator, expert, partner or energy provider, Terasen engages with stakeholders in many ways. The company maintains mutually beneficial relationships with customers, local governments, our shareholder, regulators and employees.

As an educator

As a leader in BC's energy mix, Terasen has a responsibility as an educator. The company's strategic education campaigns help customers learn about energy efficiency, natural gas safety and the rates they pay.

Safety education is a primary objective for Terasen employees who, once again, volunteered to teach natural gas safety to elementary school children. Additionally, communications aimed at the public, contractors and municipalities promoted responsible excavation practices, appliance maintenance and seasonal safety.

Meanwhile, the Customer Choice campaign marked its second year in 2008 and continued to educate the public about their energy supplier options. Energy efficiency and conservation information was also made readily available through the web, radio, newspaper and print items.

As an expert

An example of Terasen's solid reputation among regulators is its work with the Oil and Gas Commission. Recognizing the company's operational experience and history of safety and system integrity, the Commission invited Terasen to participate in the development of BC's new Pipeline and Facilities Regulations.

As a partner

Terasen is committed to being an integral part of the climate change solution.

"We serve over 125 of the 133 communities that signed BC's Climate Action Charter," said David Bodnar, director, community, government and aboriginal relations, Terasen Gas. "So it makes sense for us to provide solutions to assist in their efforts to become carbon neutral."

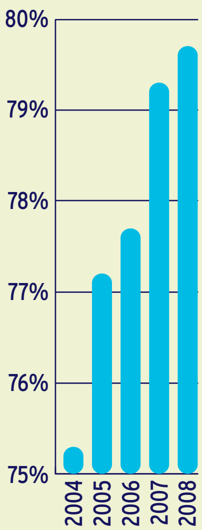
Terasen is doing just that with a range of solutions. From district energy systems and natural gas powered fleet vehicles, to biogas capture and joint energy efficiency programs—Terasen works in partnership with its stakeholders every day.

Comfort experts appear in Terasen Gas' education campaigns to promote energy efficiency, natural gas safety and Customer Choice.

As an energy provider

When it comes to satisfying customers, Terasen continues to improve on its own record. In 2008, its customer satisfaction rating was the highest in the measure's history, with 79.7 per cent indicating a high level of satisfaction. In fact, Terasen set a new customer satisfaction record in each of the last five years.

Customer satisfaction



Sustainable solutions

Kristen Mucha of Terasen Energy Services understands sustainable energy solutions. Here, she makes a site visit to Richmond's Waterstone Pier; its geothermal system provides heating and air conditioning.

Terasen Energy Services specializes in innovative alternative energy solutions with a focus on sustainability. Solutions range from geothermal systems for stand-alone buildings to complete district energy systems serving multiple buildings.

One fleet at a time

Terasen's compressed natural gas vehicle program helps businesses conserve energy, while reducing operating costs and emissions.

With technology provider FuelMaker, 100 forklifts were converted from propane to natural gas for Euro Asia Transload. The converted fleet will save 150 tonnes of carbon dioxide annually, the equivalent of removing 150 vehicles from the road. Additionally, the fleet will produce 95 per cent less carbon monoxide—a significant improvement for the employees' indoor air quality.

Initiating change for a greener future

A green blueprint

Since 1995, Terasen has reduced emissions from its operations through voluntary, efficiency-based programs.

It mitigates environmental impacts by:

- optimizing equipment
- improving operating practices
- purchasing emission offsets
- using over 100 alternative fuel fleet vehicles, including Honda's passenger vehicle, the Civic GX (fueled by compressed natural gas—the cleanest-burning hydrocarbon available)

Terasen is a leader in energy efficiency, conservation and environmental management practices. Environmental protection measures, such as the monitoring plan used for the Columbia River pipeline upgrade, are fully integrated into Terasen's business.

Living our green commitment

In 2008, Terasen applied to its regulator to expand funding for energy efficiency programs. If approved, the enhanced programs would help customers significantly reduce their natural gas use by about 1.5 million gigajoules annually. Environmental benefits would include reducing 78,500 tonnes of greenhouse gases annually, the equivalent of removing almost 16,000 vehicles from the road. Funding would be treated as a capital investment in the company's system, benefiting customers, Terasen and the environment.

Getting to zero

About 40 per cent of BC's greenhouse gases come from transportation, with commercial vehicles being the biggest emitters. Terasen's compressed natural gas vehicle program provides a clean energy alternative that significantly reduces vehicle emissions.

"I congratulate Terasen and its partners in supporting BC's Energy Plan by promoting clean, efficient natural gas vehicles as an energy alternative," said former Minister of Energy, Mines and Petroleum Resources, Richard Neufeld, at the program launch. "It is through the support of companies like yours that we will reach the Province's climate action goals."

Last year, Terasen, FortisBC, the City of Kelowna and the Clean Air Foundation launched "Cool Shops," a free energy audit program that helped about 300 businesses reduce their annual collective greenhouse gas emissions by 36 tonnes.

Renewable by design

Consumer demand for sustainable, affordable homes has increased dramatically in the past few years. Meanwhile, Terasen continues to promote renewable, alternative energies. A deal with The Beedie Group will see Terasen design, build and manage a $25 million district energy system for The Village at Fraser Mills in Coquitlam, BC.

"We sought out Terasen Energy Services—a leader in alternative energy systems—to develop and manage a district energy system that would contribute to a leading-edge, sustainable community," said Ryan Beedie, president of The Beedie Group.

Innovative capture

Terasen is leading the way with BC's first biogas capture project. With QuestAir Technologies and Metro Vancouver, the pilot project will capture biogas from the Lions Gate Wastewater Treatment Plant and deliver it through Terasen's existing distribution system. The project, which supports BC's Energy Plan, will provide enough fuel for 100 homes and reduce greenhouse gases by 500 tonnes annually.

By working with municipalities, businesses and technology partners, Terasen is initiating change for a greener future.

Managing business soundly

Through enterprise risk management, system integrity practices and the company's alignment with ISO 14001 environmental management system standards, Terasen manages its business soundly.

A simple equation

People plus technology plus processes is a simple equation for solid business results. Take, for example, Terasen's Distribution Mobile Solution. It improved scheduling, dispatching and tracking of work and resources. By improving such efficiencies, Terasen enhanced service and reduced its costs and carbon footprint.

By land and water

In 2008, Terasen applied to its regulator to replace two pipelines crossing the Fraser River that provide natural gas to five municipalities. If approved, the replacement of the 20 and 24-inch pipelines will address potential seismic activity and mitigate river erosion. The new crossings will exemplify Terasen's risk mitigation and system integrity management practices.

End of an era

The year saw Terasen complete a program to replace the remaining low-pressure piping in its natural gas distribution system. During the past three years, 95 kilometres of steel main and 7,100 steel services were replaced with polyethylene. By doing so, Terasen ensured ongoing system integrity, safety and reliability. Completed under budget and ahead of schedule, the Vancouver Low Pressure Replacement project marked the end of an era.

Terasen also completed seven pipeline projects including improvements and relocations for provincial and municipal highway projects.

A river runs over it

Running beneath the Columbia River, a new natural gas pipeline now serves Castlegar. Using state-of-the-art, horizontal drilling equipment, Terasen installed 300 metres of new pipe, replacing the old transmission pipeline once suspended above the river by aerial towers. As with all Terasen construction projects, life in and around the river was protected, including an endangered fish species, the white sturgeon.

Fuel for growth

After five years of community consultation, a $200 million project to construct a natural gas storage facility on Vancouver Island received approval from the BC Utilities Commission. The Mt. Hayes facility is a significant addition to BC's energy infrastructure.

"Mt. Hayes will help deliver a secure natural gas supply for Vancouver Island and mainland customers well into the future," said Cynthia Des Brisay, vice president, gas supply and transmission, Terasen Gas.

Sound business management and a commitment to excellence will drive Terasen's growth and continued success today and tomorrow.

About Mt. Hayes

Terasen's natural gas storage facility provides substantial community benefits including:

- about $50 million in local construction
- direct employment for about 40 construction workers
- nine full time jobs

In service by late 2011, the facility will be supplied by the company's existing system.

Once complete, it will mean:

- cost-competitive storage close to customers
- reduced dependency on remote storage
- increased flexibility to meet energy needs

A solid foundation

At the Mt. Hayes project site, more than 1,000 cubic metres of concrete forms the foundation that will support the thermos-like structure.

When complete, the storage tank will measure about 50 metres high, 60 metres in diameter, and hold 1.5 billion cubic feet of liquefied natural gas.

Growing community spirit

Kirsten Walker, a Terasen Gas employee, was one of many employees and family members who volunteered a Saturday to help plant Terasen Garden at Holland Park in Surrey.

The event was one of three regional projects that marked Terasen's inaugural Community Giving Day. Selected by employees, each project received a $30,000 corporate donation.

Caring for communities

From public consultation and innovative training, to planting an urban garden—Terasen cares.

Involving communities

In 2008, construction began at Mt. Hayes, the site of Terasen's new natural gas storage facility on Vancouver Island. An important part of BC's energy infrastructure, the project is the outcome of extensive community involvement.

"Terasen demonstrated a real desire to work with us in its development of a significant project on our traditional land. We encourage other businesses to follow their lead," stated the late Chief Peter Seymour, Chemainus First Nation.

Terasen, the Chemainus First Nation and Cowichan Tribes signed a landmark equity agreement—the first partnership of its kind. It provides them the opportunity to share a 15 per cent equity interest in the Mt. Hayes natural gas storage facility, gaining valuable business understanding and an important revenue stream for years to come.

Preparing tomorrow's workforce

Terasen led a joint utility construction "boot camp" to train and prepare First Nations youth for potential employment in the utility construction industry.

The initiative between several BC utilities and aboriginal community representatives also received recognition and partial funding from the Province and the Sto:Lo Nation.

"The program gave us the opportunity to learn in a flexible and supportive environment," said David Harris, Chemainus First Nation.

Mr. Harris is now employed with a Chemainus crew subcontracted to install power lines to the Mt. Hayes site.

Driving community giving

Equipped with smiles and determination, employees volunteered their own time in Terasen's inaugural Community Giving Day. Selected by employees, three regional projects each received a $30,000 corporate donation.

Employees planted Terasen Garden at Surrey's Holland Park. Featuring indigenous plants and beautiful landscaping, "the garden is a definite asset to the park," said Steve Whitton, Surrey Parks development coordinator.

On Vancouver Island, volunteers supported Community Living Victoria, and in Kelowna partnered with Habitat for Humanity.

Meanwhile, Warm Hearts, the charitable foundation created, funded and managed by employees, continued its heartfelt work. Since 1994, Warm Hearts has donated close to $500,000 to BC charities. In 2008, Terasen also topped up employee donations by 50 per cent through its new Community Giving Program.

Contributing to the communities where its employees live and work is another way Terasen invests in BC's future.

Where we live and work

In 2008, Terasen employees made a difference in their communities in many ways. Events they participated in included:

- Terasen's Community Giving Day in Surrey, Kelowna and Victoria
- Great Canadian Shoreline Cleanup
- Environmental Mind Grind
- Heart & Stroke Big Bike
- CANstruction Vancouver
- Dress for Success Vancouver
- Give Where You Live fundraising campaign
- Kamloops Christmas Parade
- Kelowna Festival of Trees / Adopt-a-family
- Warm Hearts Toy Drive for Transition Homes

Investing in employees

Terasen employees are known for their hard work, dedication and innovative ideas—which is why retaining, attracting and developing valued employees is an ongoing priority.

Retaining expertise

Terasen employees are part of a culture that promotes lifelong learning and advancement, while rewarding leadership, performance and results. Employees enjoy competitive benefits and a healthy work-life balance. As well, the company supports employee-directed community giving.

Attracting talent

Terasen continues to be successful in attracting high-calibre talent despite 2008's competitive labour market. In a survey, 98 per cent of new employees cited Terasen's reputation as strongly influencing their decision to join the company. Career and development opportunities were cited by 96 per cent, and attractive benefits were identified by 92 per cent.

Developing careers

Terasen is dedicated to helping employees build long-standing careers. With a comprehensive approach to learning, the company develops talent through a variety of programs including those for trade apprenticeships, engineers-in-training, co-op and intern students.

Developing leaders is also an important part of Terasen's approach to talent management. Managers participate in development opportunities such as the company's Manager-in-Training program and the Western Energy Institute's Emerging Leaders program. Additionally, Terasen's Learning Management System provides a solid foundation for employee development, succession planning and recruitment.

Every day the company works hard to make Terasen a great place to work, where employees can thrive in their careers and continue to support the company's exciting growth objectives.

A great place to work

"In 2008, we hired 193 new employees, more than a 30 per cent increase over 2007. And our voluntary attrition rate is about 4 per cent, well below our industry peers' rate of 6.9 per cent."
Jan Marston,
vice president,
human resources
and operations
governance,
Terasen Gas

Looking forward

From the first natural gas service in Vancouver and Victoria, to the pursuit of alternative energy solutions today, Terasen and its predecessor companies have always been innovative—with a vision for British Columbia's future.

Efficient and adaptive, Terasen will continue to make important advances as the Province's needs and expectations change. Working together with communities, policy makers, regulators, and those progressive in the industry, Terasen is making its mark.

Energy solutions

Committed to doing what makes sense, Terasen will help BC move towards a leaner carbon future. Uniquely positioned across the Province as a safe, trusted, reliable and efficient operator of piped energy solutions, Terasen has a strong foundation for profitable growth opportunities.

Whistler pipeline

In 2008, construction continued on the new 50-kilometre natural gas pipeline from Squamish to Whistler.

A significant contribution to BC's energy infrastructure, the pipeline is also a key element in Whistler's Sustainable Energy Plan that calls for the existing propane system to be converted to natural gas. This conversion will reduce greenhouse gas emissions by about 15 per cent and help meet Whistler's growing energy demands.

As the energy and environment world evolves, Terasen will continue to pursue integrated energy opportunities in more diverse areas to serve the energy needs of British Columbians in the decades to come.

For 2009 and beyond, Terasen's priorities include:

- **Staying focused on operational excellence**—including safety, customer satisfaction, financial performance, and environmental responsibility
- **Contributing to BC's infrastructure**—by continuing construction of the Mt. Hayes storage facility and completing the Whistler pipeline
- **Offering alternative energies and energy efficiency opportunities**—for a cleaner, greener and more affordable future
- **Growing the business**—by pursuing new applications for natural gas and solutions that integrate piped and alternative energies
- **Retaining, attracting and investing in employees**—the cornerstone of Terasen's success

Building on its core strengths and public trust, Terasen *is* delivering British Columbia's energy future.

Management's Discussion and Analysis

For the year ended December 31, 2008

February 6, 2009

This discussion should be read in conjunction with the consolidated financial statements of the Company and related notes for the years ended December 31, 2008 and 2007. In this Management's Discussion and Analysis (MD&A), we, us, our, the Company and Terasen mean Terasen Inc., its subsidiaries, joint ventures and investments in significantly influenced companies. Terasen Gas refers to Terasen Gas Inc.; TGVI refers to Terasen Gas (Vancouver Island) Inc.; TGW refers to Terasen Gas (Whistler) Inc.; TES refers to Terasen Energy Services Inc.; CWLP refers to CustomerWorks LP; Trans Mountain refers to Terasen Pipelines (Trans Mountain) Inc.; Corridor refers to Terasen Pipelines (Corridor) Inc.; Terasen Pipelines refers to Terasen Pipelines Inc.; Express refers to the Express and Platte Pipeline Systems; the Petroleum Pipeline companies refers to Trans Mountain, Corridor, Terasen Pipelines and Express; KMI refers to Knight Inc. (formerly known as Kinder Morgan, Inc.); and Fortis or the parent refers to Fortis Inc.

The financial data included in this discussion has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), and all dollar amounts are in Canadian dollars unless otherwise stated.

Forward-looking statement

Certain statements contained in this Management's Discussion and Analysis contain forward-looking information within the meaning of applicable securities laws in Canada (forward-looking information). The words "anticipates," "believes," "budgets," "could," "estimates," "expects," "forecasts," "intends," "may," "might," "plans," "projects," "schedule," "should," "will," "would," and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this Management's Discussion and Analysis includes, but is not limited to, statements regarding: the Company's expectation to generate sufficient cash from operations to meet its working capital needs and to maintain its financial capacity and flexibility; the Company's expected capital expenditures for 2009, including estimated construction costs, the expectation to finance those expenditures with a combination of proceeds from shareholder advances, short and long-term borrowings and internally generated funds and the expectation that capital spending will not significantly decline in 2009; the Company's belief that changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts; the Company's expectation that delivery margins will not be impacted by migration of residential customers to alternative commodity suppliers; and the Company's expectation that it will not experience difficulty in servicing its debt obligations and paying common dividends.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to: receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability as a result of a catastrophic event or environmental upset; the competitiveness of natural gas pricing when compared with alternate sources of energy, continued population growth and new housing starts; the availability of natural gas supply, access to capital including no material adverse ratings actions by credit ratings agencies; interest rates; the ability to hedge certain risks including counterparties to derivative instruments failing to meet obligations; and no material change in pension expenses or funding requirements.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors that could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk; operational disruptions and environmental risk; price competitiveness risk including the impact of carbon taxes or other environmental policies of government; changes in economic conditions including population changes and declining housing starts; risk related to the development of the TGVI franchise; natural gas supply risks; capital and credit ratings risk including material adverse ratings actions by credit ratings agencies; interest rate risk; counterparty credit risk including counterparties to derivative instruments failing to meet obligations; and pension expense and funding risk. For additional information with respect to these risk factors, reference should be made to the section entitled "Commitments, events, risks and uncertainties" in this Management's Discussion and Analysis.

All forward-looking information in this Management's Discussion and Analysis is qualified in its entirety by this cautionary statement and, except as required by law, the Company undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

About Terasen

On February 26, 2007, KMI, the Company's former parent, announced it had entered into a definitive agreement with Fortis to sell Terasen and its principal natural gas transmission and distribution assets, including its subsidiaries Terasen Gas and TGVI, as well as other activities including TES. The sale did not include the petroleum transportation subsidiaries nor investments under the Kinder Morgan Canada name. The purchase price of approximately $3.7 billion included the assumption of approximately $2.4 billion of debt. The transaction closed on May 17, 2007. The Company classified its petroleum operations income and cash flow as discontinued. The Company converted any accrued interest and inter-company payables into equity and recorded this as contributed surplus.

The result of the above transactions is that Terasen's holdings are primarily natural gas transmission and distribution assets. All petroleum transportation assets, liabilities, revenues and expenses were sold after these transactions.

Natural gas transmission and distribution

Terasen's natural gas transmission and distribution operations consist primarily of Terasen Gas and TGVI in addition to several small related utility operations. Terasen Gas is the largest distributor of natural gas in British Columbia, serving approximately 834,000 residential, commercial and industrial customers in more than 100 communities. Major areas served by Terasen Gas are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of the province. TGVI serves approximately 95,000 residential, commercial and industrial customers on Vancouver Island and the Sunshine Coast area and TGW serves approximately 2,500 residential and commercial customers in the Whistler region. Terasen Gas and TGVI provide transmission and distribution services to their customers, and obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through the Company's Southern Crossing Pipeline, from Alberta.

Petroleum transportation

Terasen's petroleum transportation operations were the Trans Mountain, Corridor, Express and Platte pipelines. These operations were conducted under the Kinder Morgan Canada name. Trans Mountain transported crude oil and refined products from Edmonton, Alberta to Burnaby, British Columbia and also delivered Canadian crude oil to several refineries in Washington State. Trans Mountain also owned the Westridge Marine Terminal, which is located at tidewater in the Port of Vancouver, and a jet fuel pipeline connecting to Vancouver

International Airport. Corridor owned a dual pipeline system that transported diluted bitumen and diluent between the Muskeg River mine near Fort McMurray and the Shell upgrader north of Edmonton, Alberta. Corridor commenced commercial operations in May 2003. Terasen also owned a one-third interest in the Express Pipeline and the Platte Pipeline that transported crude oil from Hardisty, Alberta to the Rocky Mountain region of the United States and on to Wood River, Illinois.

These operations were sold in 2007 and are classified as discontinued operations at December 31, 2007 as described above.

Other activities

In addition to Terasen's core businesses of natural gas transmission and distribution and petroleum transportation, Terasen owns interests in several smaller businesses including a 30 per cent interest in CWLP and TES. CWLP provides billing and customer care services to utilities, municipalities and retail energy companies. CWLP has outsourced the provision of its customer care services to an entity owned and operated by Accenture Inc. TES provides innovative, safe and reliable alternative energy solutions with a focus on sustainability.

RESULTS OF OPERATIONS

NET EARNINGS	Three months ended December 31		Twelve months ended December 31	
In millions of dollars	**2008**	2007[2]	**2008**	2007[2]
Natural gas transmission and distribution				
Terasen Gas	**$ 38.2**	$ 41.3	**$ 88.8**	$ 81.7
TGVI and TGW	**8.7**	8.2	**30.1**	30.0
	46.9	49.5	**118.9**	111.7
Discontinued operations[1]	**-**	-	**-**	(410.2)
Other activities	**(2.3)**	(8.9)	**(17.2)**	(75.3)
Net earnings	**$ 44.6**	$ 40.6	**$ 101.7**	$ (373.8)

1 During the second quarter of 2007, Terasen entered into a series of transactions with affiliated companies whereby the assets of the Petroleum Pipeline companies were sold to the affiliated companies in April and May 2007. For a description of the transactions, see DISCONTINUED OPERATIONS below.

2 Amounts have been restated to reflect the amalgamation of Terasen during the first quarter of 2007. See Note 1 of the December 31, 2008 annual financial statements for further details.

Terasen reported earnings of $44.6 million for the three months ended December 31, 2008 compared with earnings of $40.6 million in the corresponding quarter of 2007. For the twelve months ended December 31, 2008, earnings were $101.7 million compared to a loss of $373.8 million in the twelve months of 2007. The earnings have increased due to the absence of a goodwill impairment charge taken in the first quarter of 2007 and lower interest expense in 2008.

In 2008, net earnings increased by $475.5 million compared to 2007. The significant items that impacted net earnings in 2008 compared to the previous year were as follows:

CERTAIN ITEMS

In millions of dollars	
2007 write-off of goodwill related to Trans Mountain	$ 441.9
Lower earnings in 2008 due to the sale of the Petroleum Pipelines business part way through 2007	(31.7)
2008 interest savings, net of tax, on the conversion of subordinated debt to preferred shares	30.7
2007 higher interest and other expenses due to higher borrowings in corporate and transaction related expenses that were not charged to the Trans Mountain business	28.3
2007 one-time gain on the sale of land	(8.2)
Settlement of retroactive amending Québec tax legislation	7.5
Lower loss in International due to a one-time tax provision taken in 2007	7.0
	$ 475.5

Interest expense was substantially lower in 2008 due to the conversion of subordinated debt into preferred shares in 2007. The conversion results in lower net interest expense of $30.7 million in 2008 compared to 2007. The sale of the Petroleum Pipelines business in May resulted in lower earnings of $31.7 million in 2008 compared to 2007. Corporate interest and expenses were lower in 2008 due to the conversion discussed above, and lower expenses due to transaction-related expenses incurred in 2007.

SELECTED ANNUAL INFORMATION

Years ended December 31	**2008**	2007	2006
In millions of dollars			
Total revenues[1]	**$ 1,921.5**	$ 1,768.5	$ 1,783.4
Net income (loss) before discontinued operations[1]	**101.7**	36.4	(764.2)
Net income (loss)	**101.7**	(373.8)	(687.3)
Common dividends paid	**77.0**	-	-
Total assets (restated)[1]	**4,758.6**	4,425.1	7,282.2
Long-term debt[2]	**1,841.6**	1,673.7	2,121.5
Current portion of long-term debt	**$ 78.5**	$ 470.6	$ 285.9

1 Total revenues in 2007 and 2006 have been restated to reflect the reclassification of the Petroleum Pipeline companies as discontinued operations. Total assets for 2006 have been restated to reflect the reclassification of amounts between other assets and other long-term liabilities and deferred credits.

2 Excluding current portion of long-term debt.

Results by business segment

NATURAL GAS TRANSMISSION AND DISTRIBUTION

In millions of dollars	Three months ended December 31		Twelve months ended December 31	
	2008	2007	**2008**	2007
Revenues	**$ 607.4**	$ 547.9	**$ 1,905.2**	$ 1,750.8
Operating expenses				
Cost of natural gas	**417.9**	366.7	**1,267.8**	1,128.6
Operation and maintenance	**57.9**	52.2	**199.3**	192.0
Depreciation and amortization	**24.2**	23.0	**97.3**	94.1
Property and other taxes	**13.4**	13.4	**53.5**	53.1
	513.4	455.3	**1,617.9**	1,467.8
Operating income	**94.0**	92.6	**287.3**	283.0
Financing costs	**(33.6)**	(33.4)	**(131.4)**	(125.7)
Earnings before income taxes and gain on sale of land	**60.4**	59.2	**155.9**	157.3
Gain on the sale of land	**-**	8.2	**-**	8.2
Earnings before income taxes	**60.4**	67.4	**155.9**	165.6
Income tax expense	**(13.5)**	(17.9)	**(37.0)**	(53.8)
Net earnings (loss)	**$ 46.9**	$ 49.5	**$ 118.9**	$ 111.7

For the three months ending December 31, 2008, revenues from natural gas transmission and distribution increased by $59.5 million while for the twelve months ending December 31, 2008, revenues from natural gas transmission and distribution increased by $154.4 million, compared to the corresponding periods in 2007. Revenues for the quarter and year to date from natural gas transmission and distribution increased in 2008 compared to 2007 mainly as a result of cooler weather in 2008 and the effect of higher commodity cost of gas charged to customers, which are flowed through in customer rates.

Natural gas transmission and distribution net earnings increased from $111.7 million in 2007 to $118.9 million in 2008. The increase in earnings is mainly due to strong operating performance in both Terasen Gas and TGVI and the tax benefit related to the settlement with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of retroactive amending Québec tax legislation. For the three months ended December 31, 2008, net earnings decreased by $2.6 million mainly due to the recognition of the gain on sale of land in 2007.

Terasen Gas

For the three months ended December 31, 2008, earnings decreased from $41.3 million in 2007 to earnings of $38.2 million in 2008. For the twelve months, earnings increased from $81.7 million in 2007 to earnings of $88.8 million in 2008. The decrease in earnings for the three months is mainly due to the recognition of the one-time gain on the sale of surplus land in the prior year offset partially by a higher allowed return on equity in 2008. The increase in earnings for the twelve months is mainly due to the settlement in 2008 of various tax matters including those with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of retroactive amending Québec tax legislation plus the effect of a higher allowed return on equity in 2008.

Revenues from Terasen Gas increased by $52.3 million for the three months and $139.9 million for the twelve months ending December 31, 2008, compared to the corresponding periods in 2007.

Cost of natural gas changed on a year-over-year basis, up $47.9 million in the fourth quarter and $134.9 million for the twelve months ended December 31, 2008. Higher revenues and cost of natural gas for the three and twelve months ended December 31, 2008 reflect higher consumption in the current quarter and on a year to date basis due to cooler weather and higher commodity cost of gas charged to customers. Changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts.

Terasen Gas net customer additions during 2008 were 9,256, down from 9,939 in 2007. The weakening housing and construction markets contributed to lower net customer additions in 2008 compared to 2007. In addition, the growth in multi-family housing impacted net additions as natural gas use is less prevalent in this type of dwelling. Terasen Gas industrial and transportation sales volumes decreased by 4,521.4 terajoules (TJ), mainly due to lower volumes for pulp and paper customers. Terasen Gas earns approximately the same margin regardless of whether a customer contracts for sales or transportation service.

For the three and twelve months ended December 31, 2008, operation and maintenance expenses increased by $5.2 and $6.0 million respectively, as compared with the corresponding periods of 2007. The increase in operating and maintenance expenses for the three months and twelve months is a result of higher labour costs in the current year partially offset by lower non-labour costs in the current year versus the comparative period. Non-labour costs are lower in the current year primarily due to the absence of incremental costs in 2007 associated with the Fortis transaction offset by higher bad debt and customer care costs in the current quarter and on a year-to-date basis. For the three months and twelve months ended December 31, 2008, financing costs increased by $0.3 million and $3.5 million respectively. Higher borrowing costs in the current year are due to higher borrowing rates in the current period and incrementally greater short-term borrowings versus the same period in the prior year. Income taxes for the three and twelve months of 2008 were lower than in the comparable periods of 2007 due to lower earnings, a lower effective tax rate and the net impact of the settlement of various tax matters including the retroactive amending tax legislation. During the year, the Company reached a settlement with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of retroactive amending Québec tax legislation. The legislation was passed in 2006 for the purpose of challenging certain inter-provincial Canadian tax structures. As a result of the tax settlement, an earnings benefit of approximately $5.6 million was recognized.

Regulation

Terasen Gas' rates are based on estimates of several items, such as natural gas sales volumes, cost of natural gas, and interest rates. In order to manage the risks of forecast error associated with some of these estimates, a number of regulatory deferral accounts are in place.

Two mechanisms to ameliorate unanticipated changes in forecast items have been implemented specifically for Terasen Gas. The first, originally called the Gas Cost Reconciliation Account (GCRA), relates to the recovery of all gas costs through a deferral account that captures variances (overages and shortfalls) from forecasts. Balances are either refunded to or recovered from customers via a quarterly review and application to the British Columbia Utilities Commission (BCUC). Creation of the GCRA was approved by the BCUC in October 1993. Effective April 2004, the GCRA was split into two new deferral accounts called the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA). The CCRA and MCRA were created to support customer commodity choice (unbundling) and the refund/recovery mechanism works the same as that used for the GCRA. The second mechanism seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism (RSAM).

The RSAM and CCRA/MCRA accounts reduce Terasen Gas' earnings exposure to earnings volatility by deferring any variances between projected and actual gas consumption and gas costs, and refunding or recovering those variances in rates in subsequent periods. Variances in usage by large volume, industrial transportation and sales customers are not covered by these deferral accounts as their usage is more predictable and less likely to be significantly affected by weather.

In 2008, the net balances of the RSAM and CCRA/MCRA accounts decreased to a receivable of $22.5 million from a receivable of $72.9 million in 2007. Mark-to-market adjustments on commodity cost hedges, which are out of the money at December 31, 2008 and 2007, account for $4.5 million of the change. In order to ensure that the balances in the CCRA/MCRA account are recovered on a timely basis, Terasen Gas prepares and files quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas costs. These rate adjustments ignore the temporal effect of derivative valuation adjustments on the balance sheet and instead reflect the forward forecast of gas costs over the recovery period.

Short-term and long-term interest rate deferral accounts are also in place to absorb interest rate fluctuations. The interest rate deferral accounts effectively fixed the interest rate on short-term funds attributable to Terasen Gas' regulated assets at 5.00 per cent during 2008 and 4.75 per cent for 2007. The effective fixed short-term interest rate for 2009 has been set at 4.25 per cent. Any variations from this rate are deferred.

Allowed Return on Equity (ROE) and capital structure

Terasen Gas' allowed ROE is determined annually based on a formula that resets annually off a forecast of 30 Year Canada Bonds plus a 3.90 per cent risk premium when the forecast yield on 30 Year Canada Bond is 5.25 per cent. The risk premium is adjusted annually by 75 per cent of the difference between 5.25 per cent and the forecast yield on 30 Year Canada Bonds. For 2008, the application of the ROE formula set Terasen Gas' allowed ROE at 8.62 per cent, up from 8.37 per cent in 2007. The deemed equity component for Terasen Gas is 35.01 per cent, unchanged from 2007. For 2009, the allowed ROE has been set at 8.47 per cent for Terasen Gas.

2008-2009 Performance Based Rate Plan (PBR)

In July 2003, Terasen Gas received BCUC approval of a negotiated settlement for a 2004-2007 PBR. The PBR Settlement establishes a process for determining Terasen Gas' delivery charges and incentive mechanisms for improved operating efficiencies. The four-year agreement included incentives for Terasen Gas to operate more efficiently through the sharing of the benefits between Terasen Gas and its customers. The PBR Settlement includes 10 service quality measures designed to ensure Terasen Gas maintains adequate service levels. It also sets out the requirements for an annual review process that will provide a forum for discussion between Terasen Gas and interested parties regarding its current performance and future activities.

Operation and maintenance costs and base capital expenditures were subject to an incentive formula reflecting increasing costs due to customer growth and inflation, less an adjustment factor based on 50 per cent of inflation during the first two years of the PBR and 66 per cent of inflation during the last two years. Base capital expenditure amounts are a function of customer numbers and projected customer additions. The PBR Settlement provides for a 50/50 sharing mechanism of earnings above or below the allowed return on equity beginning in 2004.

In 2007, Terasen Gas applied for an extension of the 2004-2007 PBR settlement agreement. The application requested approval to extend the existing settlement term for 2008-2009. On March 23, 2007, the BCUC approved the application as filed.

Unbundling

Over the past several years, Terasen Gas, the BCUC and a number of interested parties have laid the groundwork for the introduction of natural gas commodity unbundling. On November 1, 2004, commercial customers of Terasen Gas became eligible to sign up to buy their natural gas commodity supply directly from third-party suppliers. Terasen Gas continues to provide delivery of the natural gas. Approximately 80,000 commercial customers are eligible to participate in commodity unbundling. By December 31, 2008, 19,800 customers elected to participate in this program.

During 2006, the BCUC approved offering commodity supply choice to residential customers. The BCUC agreed to open a portion of the Province's residential natural gas market to competition, allowing homeowners to sign long-term fixed price contracts for natural gas with companies other than Terasen Gas starting in May 2007. Consumers can choose to remain with Terasen Gas or sign with a marketer, in which case they began receiving gas at the marketer's rate starting in November 2007. Terasen Gas will continue to provide delivery service to unbundled customers and delivery margins are not expected to be impacted by migration of residential customers to alternative commodity suppliers. Approximately 748,000 residential customers are eligible to participate in commodity unbundling. By December 31, 2008, 115,500 customers elected to participate in this program.

Municipal leasing transactions

The Company has leasing arrangements that allow Terasen Gas to continue to operate the gas distribution assets by effectively selling the assets to the municipality and leasing them back for a 17-year period. After 17 years, Terasen Gas has an option to repurchase the assets at depreciated value. At December 31, 2008, Terasen Gas had entered into transactions involving a total value of $153 million. In addition the municipalities participating in the leasing transactions have the right each year to acquire any new asset additions within their boundaries at cost, subject to the same repurchase option at the end of the initial 17-year lease term.

Terasen Gas (Vancouver) Island

Earnings from TGVI increased from $30.0 million in 2007 to $30.1 million in 2008.

For the twelve months ending December 31, 2008, revenues from TGVI increased by $14.5 million compared to the corresponding period in 2007. Cost of natural gas changed on a year-over-year basis, up $4.3 million. Higher revenues and cost of natural gas for the twelve months ended December 31, 2008 reflect higher consumption in the year due to cooler weather on a year-over-year basis. Changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts.

TGVI net customer additions during 2008 were 3,574, down slightly from 3,922 customer additions in 2007. The weakening housing and construction markets contributed to lower net customer additions in 2008 compared to 2007. In addition, the growth in multi-family housing impacted net additions as natural gas use is less prevalent in this type of dwelling. TGVI industrial and transportation sales volumes decreased by 1,215.2 TJ compared to the previous year. The decrease is primarily due to the Vancouver Island Joint Venture requiring lower volumes in 2008 compared to 2007.

For the twelve months ended December 31, 2008, operation and maintenance expenses increased by $1.3 million compared with the corresponding period of 2007. The increase in operations and maintenance expenses was mainly a result of higher inspection and maintenance costs in 2008 compared to 2007. For the three and twelve months ended December 31, 2008, depreciation and amortization increased by $1.0 million and $3.3 million respectively, compared to the corresponding periods of 2007. The increase in depreciation is due to increased capital assets spending in 2007 compared to the prior years. Financing costs for the twelve months ended December 31, 2008 were higher than the comparable period due to incrementally higher rates of interest on the debenture issued in 2008 compared to short-term borrowings in the prior year. Income taxes were higher for the twelve months ended December 31, 2007 due to higher income.

Regulation

TGVI is also regulated by the BCUC. In 1995, an agreement was entered into between TGVI, the Province of British Columbia (the Province) and the Government of Canada, which included a Special Direction that was issued to the BCUC. The agreement, which expires no sooner than December, 2011, includes the following terms:

- TGVI receives, for the benefit of its customers, an annual payment until 2011 from the Province based on the wellhead price of natural gas in BC. This payment amounted to $43.1 million in 2008, up from $35.1 million in 2007.
- The accumulated revenue deficiency resulting from overall revenues being below the cost of service prior to 2003 had been recorded in a Revenue Deficiency Deferral Account (RDDA). When Terasen acquired TGVI, the amount of the RDDA was $85 million, for which Terasen paid a price of $61 million. The accumulated RDDA recorded on Terasen's consolidated financial statements totals $3.6 million as at December 31, 2008, corresponding to a balance for TGVI regulatory purposes of $7.1 million. The balance on Terasen's consolidated financial statements is down $17.5 million from December 31, 2007. Terasen is committed to fund these revenue deficiencies by purchasing preferred shares or subordinated debt issued by TGVI. The BCUC was directed to set rates beginning in 2003 that amortize the RDDA balance over the shortest period reasonably possible, having regard for TGVI's competitive position relative to alternative energy sources and the desirability of reasonable rates. The earnings impact of the RDDA discount is discussed under "Results—Natural gas transmission and distribution."
- Any variances in the achieved ROE in a particular year from the allowed ROE (other than variances resulting from operation and maintenance costs) are deferred and recorded in the RDDA. The RDDA accumulated by TGVI is funded by the Company. Recovery of the deficiency through rates charged to customers is dependent upon regulatory approval and must be balanced against maintaining the competitiveness of TGVI's service relative to alternative energy sources. As a result, most risks associated with TGVI's annual financial results (other than operating costs) are, subject to BCUC approval, transferred to customers through the RDDA. The Company began recovery of the deficiency in 2003.

Similar to Terasen Gas, in 2007 TGVI applied for a two-year extension of its settlement agreement, which would have expired at the end of 2007. The BCUC approved the application, which grants the extension until the end of 2009. The extension provides for a continuation of the operation and maintenance cost incentive arrangements previously in place. The allowed ROE for TGVI was 9.32 per cent for 2008 compared to 9.07 per cent in 2007. The deemed equity component for TGVI is 40 per cent, unchanged from 2007. Due to a decrease in the forecast benchmark 30-year Canada Bond, TGVI's ROE for 2009 has been set at 9.17 per cent.

To ensure prompt recovery of the RDDA, the BCUC has approved a rate-setting mechanism for TGVI whereby customer rates are set at levels in excess of TGVI's cost of service, but effectively capped by the price of competitive alternative fuels (electricity or heating oil). This has resulted in significant RDDA amortization in both 2008 and 2007. However, RDDA recovery is sensitive to the relative pricing of natural gas and electricity in TGVI's service area, as well as to margin generated under TGVI's firm transportation agreements discussed below. There is no certainty that TGVI will be able to charge rates that will be sufficient to fully recover the RDDA prior to the expiry of the Provincial royalty payments at the end of 2011.

Contractual arrangements

In 2007, the BCUC approved several agreements between TGVI and BC Hydro, subject to certain conditions. The principal agreement approved was a long-term Transportation Service Agreement (TSA) under which TGVI will provide BC Hydro with both firm and interruptible transportation service. Firm service will be provided in respect of the contract demand volume prevailing from time to time under the TSA. The initial term of the TSA is from January 1, 2008 to April 12, 2022. The initial contract demand is 45 TJ per day, which BC Hydro can change to a minimum of 40 TJ per day or a maximum of 50 TJ per day by giving 12 months notice. Tolls for firm and interruptible service will be determined by the BCUC from time to time. BC Hydro may elect to terminate the TSA on or after November 1, 2015 upon giving two years notice. In addition, BC Hydro may reduce the contract demand or terminate the TSA if TGVI gives notice of its intention to construct expansion facilities of a material nature (excluding the Mt. Hayes Storage Facility) that would impact transportation tolls payable by BC Hydro. If BC Hydro elects to terminate, it may by the terms of the TSA be required to make a termination payment to TGVI that would in essence compensate TGVI for incremental revenue requirements relating to expansion facilities constructed by TGVI after January 1, 2008, but prior to BC Hydro's notice of termination.

On November 15, 2007, the BCUC granted a Certificate of Public Convenience and Necessity (CPCN) to TGVI for construction of a liquefied natural gas storage facility near Mt. Hayes on Vancouver Island and related works on TGVI's existing pipeline system, subject to certain conditions. On April 1, 2008, the BCUC provided final approval to construct and operate a natural gas storage facility at Mt. Hayes on Vancouver Island. The project has an estimated construction cost of $200 million and is expected to be in service in 2011, at which time it will be included in TGVI's rate base for regulatory purposes. In addition, TGVI entered into a foreign exchange futures contract to mitigate the foreign exchange risk associated with the US dollar portion of the Engineering, Procurement and Construction (EPC) contract.

The BCUC also approved a 35-year storage and delivery agreement between TGVI and Terasen Gas, subject to certain amendments, under which TGI will contract for at least two-thirds of the storage capacity and deliverability provided by the storage facility. TGVI may reduce the level of storage and delivery provided to TGI for the last 15 years of the agreement to reflect capacity required to serve customers on TGVI's pipeline system.

DISCONTINUED OPERATIONS

	Three months ended December 31		Twelve months ended December 31	
In millions of dollars	**2008**	2007	**2008**	2007
Net (loss) earnings from discontinued operations	**$ -**	**$ -**	**$ -**	$ (410.2)

On April 30, 2007, Terasen sold the assets of the Trans Mountain system to Kinder Morgan Energy Partners for proceeds of $549 million US. During the month of May, the remaining Petroleum Pipelines businesses within Terasen were transferred to a company affiliated with Kinder Morgan Energy Partners for fair value. In return for the assets, the Company redeemed $1,311.5 million of preferred shares. The Company has recorded an after-tax charge to equity in the amount of $531.2 million related to the sale of these businesses. Additionally, the Company recorded a goodwill impairment charge of $441.9 million during the first quarter of 2007.

OTHER ACTIVITIES

In millions of dollars	Three months ended December 31		Twelve months ended December 31	
	2008	2007	**2008**	2007
Revenues	**$ 4.9**	$ 2.7	**$ 16.3**	$ 17.7
Operating expenses:				
Cost of revenues	**-**	0.4	**0.2**	8.0
Operation and maintenance	**0.6**	2.5	**4.9**	5.8
Depreciation and amortization	**2.3**	1.4	**6.7**	5.6
Property and other taxes	**-**	-	**-**	0.2
	2.9	4.3	**11.8**	19.6
Operating income (loss)	**2.0**	(1.6)	**4.5**	(1.9)
Financing costs	**(8.6)**	(8.4)	**(36.1)**	(96.8)
Loss before income taxes	**(6.6)**	(10.0)	**(31.6)**	(98.7)
Income taxes recovery	**4.3**	1.1	**14.4**	23.4
Net loss	**$ (2.3)**	$ (8.9)	**$ (17.2)**	$ (75.3)

During the fourth quarter of 2008, revenues from other activities increased by $2.2 million while during the twelve months of 2008, revenues from other activities decreased by $1.4 million on a year-over-year basis. At the end of the first quarter of 2007, CWLP lost a major customer contract that resulted in substantially lower revenue and cost of revenue compared to prior periods. In 2008, the Company invested in FortisWest Inc. (FortisWest) preferred shares that has resulted in increased revenue from the fixed preferential cumulative cash dividend associated with this investment. Cost of revenues from other activities declined by $0.4 million for the three months and $7.8 million for the twelve months ended December 30, 2008. The cost of revenues is lower due to the loss of major contracts as discussed above. Operations and maintenance expense is lower by $1.9 million and $0.9 million for the three and twelve months ended December 31, 2008 due to a charge recognized in the prior year for the loss on the wind-up of one of the Terasen International businesses. Depreciation and amortization is higher by $0.9 million and $1.1 million for the three and twelve months ended December 31, 2008. The depreciation is a result of accelerated depreciation on the assets within CWLP. The depreciation was accelerated to recover the assets value by the end of CWLP's contract with its major customer rather than their original expected useful lives. Finance charges for the fourth quarter of 2008 were higher by $0.2 million while during the twelve months of 2008, finance charges were $60.7 million lower on a year-over-year basis. The finance charges were lower for the twelve months of 2008 due to the conversion of the subordinated debt into preferred shares in May 2007. The conversion was part of the overall transaction upon the sale of Terasen to Fortis. Income tax recovery for the twelve months ended December 31, 2008 decreased by $9.0 million mainly due to the conversion of the subordinated debt to equity during May 2007.

Commitments, events, risks and uncertainties

The Company is subject to commitments, events, risks or uncertainties that may affect the Company's future performance including revenue and income or loss. The Company's key risk factors include, but are not limited to the following:

Regulation

Through the regulatory process, the BCUC approves the return on equity that Terasen Gas and TGVI are allowed to earn, in addition to various other aspects of utility operations. In addition, the recovery of costs incurred in constructing and operating the gas utility is subject to the approval of the BCUC. Fair regulatory treatment that allows Terasen Gas and TGVI to earn a fair risk adjusted rate of return comparable to that available on alternative, similar risk investments is essential for maintaining service quality as well as ongoing capital attraction and growth. Since 1994, subject to minor modifications, the allowed ROE has been set based on a formula linked directly to forecast 30-year Canada Bond yields that have steadily declined in recent years. It is essential that the Company maintain good relationships with its various regulators and customer representatives. Terasen Gas and TGVI will be challenging the current generic ROE adjustment mechanism and increases to deemed equity thickness to more fair and appropriate levels. The Company intends to file an application with the BCUC in the second quarter of 2009.

Terasen Gas' 2004-2007 PBR settlement agreement, which has been extended through 2009, includes incentive mechanisms that provide Terasen Gas with an opportunity to earn returns in excess of the allowed return on equity determined by the BCUC. TGVI's regulatory settlement, which has been extended through 2009, includes operation and maintenance cost incentives. Upon expiry of these settlements, there is no certainty as to whether new negotiated settlements will be entered into, or what the terms of the new settlements might be.

Terasen Gas and TGVI are currently preparing rate applications with anticipated filing with the BCUC in the second quarter of 2009. BCUC approval of rates for 2010, and for future years, will be required. There can be no assurance that the rate orders issued will permit the Company to recover all costs actually incurred and to earn the expected rate of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the Company, the undertaking or timing of proposed upgrades or expansion projects, the issue and sale of securities, ratings assigned by rating agencies, and other matters which may, in turn, negatively impact the Company's results of operations or financial position.

Operations and the environment

The Company is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety. The costs arising from compliance with such laws, regulations and guidelines may be material to the Company. The process of obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, contentious and expensive. Potential environmental damage and costs could arise due to a variety of events and could be material if an event happened. However, there can be no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs may have a material effect on the business, results of operations, financial condition and prospects of the Company.

The Company is exposed to environmental risks that owners and operators of properties in British Columbia generally face. These risks include the responsibility of any current or previous owner or operator of a contaminated site for remediation of the site, whether or not such person actually caused the contamination. In addition, environmental and safety laws make owners, operators and persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval. The Company has not been notified of any such regulatory action in regard to the operation or occupation of its facilities. However, it is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety laws could also lead to significant increases in costs to the Company.

The Company is exposed to various operational risks, such as pipeline leaks; accidental damage to, or fatigue cracks in mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas, which could result in significant operational disruptions and/or environmental liability. The Company believes it has taken all reasonable and prudent steps to minimize its exposure in the case of a catastrophic event or environmental upset. The Company conducts its operations utilizing an Environmental Management System that specifies impacts, control measures and audit protocols. The Company maintains comprehensive facility risk assessment, pipeline integrity management and damage prevention programs and pipeline security systems as preventive measures to mitigate the risk of a pipeline failure or other loss of system integrity. These programs are intended to reduce both the likelihood and severity of the business interruption and/or environmental liability that could result from a pipeline failure or loss of integrity.

A major natural disaster, such as an earthquake affecting the Greater Vancouver region or Vancouver Island, could severely damage Terasen Gas' or TGVI's natural gas transmission and distribution systems. The Company has detailed emergency preparedness plans in place to respond to natural disasters, accidents and emergencies, and regularly tests these plans in simulations involving employees and other emergency response organizations. The Company also has an insurance program which provides coverage for business interruption, liability and property damage, although the coverage offered by this program is limited. In the event of a large uninsured loss caused by a natural disaster, the Company would apply to the BCUC for recovery of these costs through higher rates. However, there is no assurance that the BCUC will approve any such application.

The actions necessary to abandon pipeline systems at the eventual end of their useful lives have not been defined and the costs of these actions may not be fully recovered in rates or tolls. Until such time as the specified requirements of abandonment and the funding mechanism for the eventual recovery of negative salvage is determined, the Company, like other Canadian pipeline systems, makes no provision for these amounts.

Terasen Gas' and TGVI's natural gas transmission and distribution systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the Company determines expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures which the Company believes are necessary to maintain, improve and replace their assets; the failure by the Company to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures despite maintenance programs could have a material effect on the Company.

The Company continually develops capital expenditure programs and assesses current and future operating and maintenance expenses that will be incurred in the ongoing operation. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. If actual costs exceed regulatory-approved capital expenditures, it is uncertain as to whether such additional costs will receive regulatory approval for recovery in future customer rates. The inability to recover these additional costs could have a material effect on the financial condition and results of operations of the Company. See "Regulation" for further discussion on regulatory risk.

Competitiveness

Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, because electricity prices in British Columbia continue to be set based on the historical average cost (primarily hydro-electric dams) of production, rather than based on market forces, they have remained artificially low compared to market-priced electricity. As a result, the price of electricity for residential customers in British Columbia is now only marginally higher than for natural gas. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future.

The Company employs a number of tools to reduce its exposure to natural gas price volatility. These include purchasing gas for storage and adopting hedging strategies, which include a combination of both physical and financial transactions, to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive against electric rates. Activities related to the hedging of gas prices are approved by the BCUC and gains or losses accrue entirely to customers.

If natural gas pricing becomes uncompetitive with electricity prices or the price of other forms of energy, the Company's ability to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the Company's cost of service in rates charged to customers.

In 2008 the Government of British Columbia introduced changes to energy policy including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels that impact the competitiveness of natural gas versus non-carbon based energy sources or alternate energy sources. It did not, however, introduce carbon tax on imported electricity generated through the combustion of carbon-based fuels. The future impact of these changes in energy policy may have a material impact on the competitiveness of natural gas relative to other energy sources.

There can be no assurance that the current regulatory-approved flow through mechanisms in place allowing for the flow through of the cost of natural gas will continue to exist in the future. An inability of the Company to flow through the full cost of natural gas could materially affect the Company's results of operations, financial position and cash flows.

Labour relations

Approximately 75 per cent of the employees of the Company are members of labour unions that have entered into collective bargaining agreements with the Company. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by the Company. The Company considers its relationships with its labour unions to be positive but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed.

The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have an adverse effect on the results of operations, cash flow and net income of the Company.

Impact of changes in economic conditions

Typical of utilities, economic conditions in the Company's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. New customer additions at the

Company are typically a result of population growth and new housing starts, which are affected by the state of the provincial economy. The Company is also affected by changes in trends in housing starts from single-family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. Housing starts in 2008 were more moderate compared to the previous number of years, and the growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. Higher energy prices can dampen economic activity and reduce consumption by customers. Natural gas and crude oil prices are closely correlated with natural gas and crude oil exploration and production activity in certain of the Company's service territories. The level of these activities can influence energy demand.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of Terasen Gas and TGVI, including various mitigating measures approved by regulators, helps to reduce the impact that lower energy demand, associated with poor economic conditions, may have on the Company's earnings. However, a severe and prolonged downturn in economic conditions could materially affect the Company despite regulatory measures available for compensating for reduced demand. For instance, significantly reduced energy demand in the Company's service territories could reduce capital spending that would in turn impact rate base and earnings growth. Despite current depressed economic conditions and natural gas prices, which are expected to continue during 2009, the Company does not anticipate any significant decrease in capital spending in 2009.

Risk related to TGVI

TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service and to recover revenue deficiencies from prior years. Recovery of accumulated revenue deficiencies from prior years puts gas at a cost disadvantage relative to electricity. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement (VINGPA) provides royalty revenues from the Government of British Columbia which currently covers approximately 20 per cent of the current cost of service. These revenues are due to expire at the end of 2011, after which time TGVI's customers will be required to absorb the full commodity cost of gas, all other costs of service and the recovery of any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining $60.8 million non-interest bearing senior government debt, which is currently treated as a government contribution against rate base, will be required to be repaid. As this debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates, making gas less competitive with electricity on Vancouver Island.

Natural gas supply

The Company is dependent on a limited selection of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas where the majority of the Company's natural gas distribution customers are located. Regional market prices have been higher from time to time than prices elsewhere in North America as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in BC and the US Pacific Northwest.

In addition, the Company is critically dependent on a single source transmission pipeline. In the event of a prolonged service disruption on the Spectra transmission system, the Company's residential customers could experience outages, thereby affecting revenues and incurring costs to safely relight customers.

Capital resources and liquidity

The Company's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) will not be sufficient to fund the repayment of all outstanding liabilities when due as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and to repay existing debt.

Generally, the Company is subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings impact the level of credit risk spreads on new long-term debt issues and on the Company's credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the Company's finance charges. Also, a significant downgrade in Terasen or Terasen Gas' credit ratings could trigger margin calls and other cash requirements under Terasen Gas' natural gas purchase and natural gas derivative contracts. The Company's corporate investment-grade credit ratings were confirmed and maintained during the year and the Company does not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the current global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria that may result in changes to credit rating practices and policies.

The recent and expected continued volatility in the global financial and capital markets will likely increase the cost of and affect the timing of issuance of long-term capital by the Company in 2009. The cost of borrowing is expected to increase as new long-term debt is expected to be issued at higher rates due to an increase in credit spreads. Due to the regulated nature of Terasen Gas and TGVI, the expected higher cost of borrowing of Terasen Gas and TGVI is eligible to be recovered in future customer rates.

To help mitigate liquidity risk, Terasen Gas and TGVI have secured multi-year committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

Transition to International Financial Reporting Standards

The Accounting Standards Board of the Canadian Institute of Chartered Accountants has announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board, effective January 1, 2011. IFRS will require increased financial statement disclosure as compared to Canadian GAAP, and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by the Company. The Company is currently considering the impact a conversion to IFRS would have on its future financial reporting. Additional information on the Company's transition to IFRS is provided in the "Future accounting pronouncements" section of this MD&A.

Interest rates

The allowed returns on equity for Terasen Gas and TGVI are determined by formulae that result in lower allowed ROEs if forecast long-term Canada bond yields decline. Terasen Gas' and TGVI's exposure to short-term interest rates are covered by regulatory deferral accounts; however, the Company is exposed to changes in short-term interest rates through debt on non-regulated operations.

Employee future benefits

The Company maintains defined benefit pension plans and there is no certainty that the pension plan assets will be able to earn the assumed rate of returns. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed return on the assets causing material changes in the pension expense and funding requirements. The regulated operations of the Company currently have a deferral mechanism that allows for deferral of the pension expense that is approved for recovery in rates and the actuarial pension expense. Net pension expense is impacted by, among other things, the amortization of experience and actuarial gains or losses and expected and actual return on plan assets. Market-driven changes impacting other pension assumptions, including the assumed discount rate, may also result in future contributions to pension plans that differ significantly from current estimates as well as causing material changes in pension expense. There is also measurement uncertainty associated with pension expense, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation due to measurement uncertainty inherent in the actuarial valuation process.

Counterparty credit risk

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Company is also exposed to significant credit risk on physical off-system sales. Terasen deals with high credit quality institutions in accordance with established credit approval practices. Due to recent events in the financial markets including significant international government intervention in the banking systems and financial markets the Company has further limited the financial counterparties that it transacts with and reduced available credit to, or taken additional security from, the physical off-system sales counterparties it deals with. To date, the Company has not experienced any counterparty defaults and does not expect any counterparties to fail to meet their obligations; however, the credit quality of counterparties, as recent events have indicated, can change rapidly.

First Nations lands

Terasen Gas, TGVI and TGW provide service to customers on First Nations lands and maintain gas distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Company is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as the Company. However, there can be no certainty that the settlement process will not adversely affect the business of the Company.

Critical accounting estimates

The preparation of the Company's consolidated financial statements in accordance with GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The Company's critical accounting estimates are discussed below.

Regulation

Generally, the accounting policies of the Company's regulated operations are subject to examination and approval by the respective regulatory authorities. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated operations and have been recorded based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Company's regulated operations operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known. As at December 31, 2008, the Company recorded $121.2 million in current and long-term regulatory assets (December 31, 2007 - $128.2 million) and $68.8 million in current and long-term regulatory liabilities (December 31, 2007 - $31.2 million).

Capital asset amortization

Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2008, the Company's consolidated utility capital assets were $2.9 billion, or approximately 61 per cent of total consolidated assets, compared to consolidated utility assets of $2.8 billion, or approximately 64 per cent of total consolidated assets, as at December 31, 2007. Changes in amortization rates can have a significant impact on the Company's amortization expense.

As part of the customer rate setting process, appropriate amortization rates are approved by the respective regulatory authorities for the Company's regulated operations.

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed for the regulated operations. Based on the results of these depreciation studies, the impact of any over or under amortization as a result of actual experience differing from that expected and provided for in previous amortization rates is generally reflected in future amortization rates and amortization expense, and such differences are reflected in future customer rates.

Capitalized overheads

As required by the BCUC, Terasen Gas, TGVI and TGW capitalize overhead costs that are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. These General Expenses Capitalized (GEC) are allocated over constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the respective regulators. In 2008, GEC totaled $32.7 million (2007 - $32.6 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a significant impact on the amount recorded as operating expenses and utility capital assets.

Goodwill impairment assessments

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

The Company is required to perform an annual impairment test and at such time any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. In July of each year, the Company reviews for impairment of goodwill, which is based on current information and fair market value assessments of the reporting units being reviewed. Fair market value is determined using net present value financial models and management's assumption of future profitability of the reporting units. There was no impairment provision required on $818.1 million in goodwill recorded on the Company's balance sheet as at December 31, 2008.

Employee future benefits

The Company's defined benefit pension plans and Other Post Employment Benefits (OPEB) plans are subject to judgments utilized in the actuarial determination of the expense and related obligation. The main assumptions utilized by management in determining pension expense and obligation are the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets.

The assumed long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating pension expense for 2009, is 7.25 per cent, consistent with the assumed long-term rate of return used for 2008.

The assumed discount rate, used to measure the Company's accrued pension benefit obligations on the applicable measurement date in 2008, and to determine pension expense for 2009 was 6.25 per cent, up from 5.25 per cent used in 2007. The discount rate increased as a result of the impact of increased credit risk spreads on investment grade corporate bonds due to volatility in the capital markets.

The long-term rate of return is based on the expected average return of the assets over a long period given the relative asset mix. The discount rate is determined with reference to the current market rate of interest on high-quality debt instruments with cash flows that match the time and amount of expected benefit payments.

Terasen expects consolidated pension expense for 2009 related to its defined benefit pension plans to be approximately $0.7 million lower than in 2008. The lower expense is due to the effect of the change in discount rate partially offset by lower returns on the assets in 2008.

The following table provides the sensitivities associated with a 100 basis point increase in the expected long-term rate of return on plan assets and discount rate on 2008 net benefit expense and the accrued benefit pension asset and liability recorded in the Company's consolidated financial statements, as well as the impact on the accrued pension benefit obligation.

Increase (decrease) (in millions of dollars)	Accrued benefit assets	Accrued benefit liability	Net benefit expense	Benefit obligation
1% increase in the expected rate of return	$ 2.6	$ (0.1)	$ (2.6)	$ -
1% decrease in the expected rate of return	(2.6)	0.1	2.6	-
1% increase in the discount rate	(0.8)	(0.7)	0.1	(18.5)
1% decrease in the discount rate	(2.7)	1.1	3.7	21.0

The above table reflects the changes before the effect of the regulatory deferral account that would defer most of the effect on the expense.

Other assumptions applied in measuring defined benefit pension expense and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The Company's OPEB plans are also subject to judgments utilized in the actuarial determination of the expense and related obligation. Except for the assumptions of the expected long-term rate of return on plan assets and average rate of compensation increase, the above assumptions, along with health care cost trends, were also utilized by management in determining OPEB plan expense and obligations.

As disclosed under the "Commitments, events, risks and uncertainties" section of this MD&A, Terasen Gas has regulatory-approved mechanisms to defer variations in pension expense from forecast pension expense, used to set customer rates, as a regulatory asset or a regulatory liability.

As at December 31, 2008, the Company had a consolidated accrued benefit asset of $226.3 million (December 31, 2007 - $261.2 million) and a consolidated accrued benefit liability of $351.0 million (December 31, 2007 - $360.2 million). During 2008, the Company recorded consolidated net benefit expense of $12.9 million (2007 - $16.0 million).

Asset Retirement Obligations (AROs)

In measuring the fair value of AROs, the Company is required to make reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. The Company does not currently have any identified AROs and as such no amounts have been recorded as at December 31, 2008 and 2007. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the transmission and distribution systems are reasonably expected to operate in perpetuity due to the nature of their operation; and applicable licences, permits and laws are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and to ensure the continued provision of service to customers. In the event that environmental issues are identified, or the applicable licences, permits, laws or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

Revenue recognition

The Company recognizes revenue on an accrual basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish gas consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated gas sales to customers for the period since the last meter reading at the approved rates. The development of the sales estimates requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas consumption will result in adjustments to gas revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2008, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $246.7 million (December 31, 2007 - $173.8 million) on annual consolidated operating revenues of $1.9 billion (2007 - $1.8 billion).

Contingencies

The Company is subject to various legal proceedings and claims that arise in the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Company's financial position or results of operations. Contingencies are described in Note 17 to the Company's annual financial statements.

QUARTERLY FINANCIAL INFORMATION

In millions of dollars	For the three months ended									
2008	Mar 31[1]		Jun 30		Sep 30		Dec 31		Total	
Revenues	$	638.6	$	394.2	$	276.4	$	612.3	$	1,921.5
Net income (loss)		52.4		5.7		(1.0)		44.6		101.7
2007[1]										
Revenues (restated)[2]	$	639.1	$	346.1	$	232.7	$	550.6	$	1,768.5
Net income (loss) before discontinued operations		27.5		(22.4)		(9.3)		40.6		36.4
Net income (loss)		(396.4)		(8.7)		(9.3)		40.6		(373.8)

1 Amounts have been restated to reflect the amalgamation of Terasen during the first quarter of 2007. See Note 1 of the December 31, 2008 annual financial statements for further details.

2 Revenues for 2007 have been restated to reflect the reclassification of the Petroleum Pipelines companies as discontinued operations.

Because of natural gas consumption patterns, the natural gas transmission and distribution operations of Terasen Gas normally generate higher earnings in the first and fourth quarters and lower earnings in the second quarter, which are partially offset by losses in the third quarter. As a result of the gas distribution segment seasonality, interim earnings statements are not indicative of earnings on an annual basis.

March 2008/2007—Earnings increased by $448.8 million due to the absence of a goodwill impairment charge of $441.9 million in the first quarter of 2007 slightly offset by the sale of the Petroleum Pipelines businesses in 2007. The March 2007 earnings include results from the Petroleum Pipelines segment while the results in 2008 do not as a result of the sale of the businesses. Additionally, earnings are higher in the current year due to the conversion of the subordinated debt into preferred shares in May 2007.

June 2008/2007—Earnings increased by $14.4 million due to the conversion of subordinated debt into preferred shares in May 2007 offset slightly by lower earnings due to the sale of the Petroleum Pipelines businesses in 2007. Additionally, more customers and an increase in the return on equity increased the earnings from the natural gas transmission and distribution operations.

September 2008/2007—Earnings increased by $8.3 million mainly due to the settlement of the retroactive amending tax legislation. As a result of the tax settlement, an earnings benefit of approximately $7.5 million was recognized. Additionally, more customers and an increase in the return on equity increased the earnings from the natural gas transmission and distribution operations.

December 2008/2007—Earnings increased by $4.0 million mainly due to higher return on equity, lower operations and maintenance expense and lower tax expense in the current period versus the prior year.

Liquidity and capital resources

Terasen expects to generate sufficient cash from operations to meet its working capital needs and to maintain its financial capacity and flexibility.

CONSOLIDATED CASH FLOW

	Three months ended December 31		Twelve months ended December 31	
In millions of dollars	**2008**	2007	**2008**	2007
Cash flow provided by (used for):				
Operating activities	**$ 79.8**	$ (5.9)	**$ 255.5**	$ 113.5
Investing activities	**(52.3)**	(39.7)	**(314.5)**	(306.2)
Financing activities	**(25.3)**	63.7	**74.2**	199.3
Net (decrease) increase in cash	**$ 2.2**	$ 18.1	**$ 15.2**	$ 6.6

Cash flow from operating activities

Cash flow from operating activities increased from $113.5 million in 2007 to $255.5 million in 2008 due to a number of factors. Net earnings from continuing operations were $65.3 million higher in 2008 as a result of the items outlined on page 18. Cash from operations refers to cash generated before the impact of working capital. Cash from operations for the three months ended December 31, 2008 was $66.1 million compared to $54.7 million in the corresponding period of 2007. Cash from operations for the twelve months ended December 31, 2008 was $201.0 million, compared to $123.0 million in the corresponding period of 2007. The increase in cash from operations for the three and twelve months ended December 31, 2008 is mainly a result of higher net earnings in the comparable periods of 2008 versus 2007.

Between December 31, 2007 and December 31, 2008, accounts receivable, inventories of gas in storage and supplies, accounts payable and accrued liabilities, excluding the mark-to-market on gas derivative, have increased while the current portion of rate stabilization accounts decreased as a result of the cooler weather and higher commodity cost of gas charged to customer. Due to the greater impact of these changes in 2008 as compared to 2007, cash flow generated from operating activities has increased.

Investing activities

Capital expenditures totaled $213.0 million in the twelve months ended December 31, 2008 compared with $174.6 million in the corresponding period in 2007. The increase in capital expenditures was primarily attributable to work on the Mt. Hayes Natural Gas Storage project on Vancouver Island and the Whistler Pipeline project.

Additionally, Terasen invested $150 million in FortisWest preferred shares.

In 2007, there was a net use of cash of $163.2 million related to the disposal of the Petroleum Pipelines businesses during the second quarter. The cash flows of the comparative periods have been restated to reflect the classification of the Petroleum Pipelines businesses as discontinued operations.

Financing activities

On February 15, 2008, TGVI issued $250.0 million of Medium-Term Note Debentures at a coupon interest rate of 6.05 per cent. The proceeds were used to repay the current operating facility.

On May 13, 2008, Terasen Gas issued $250.0 million of Medium-Term Note Debentures at a coupon interest rate of 5.80 per cent. The proceeds were used to repay current debt maturities of $188.0 million, which matured on June 2, 2008, and the remainder of the proceeds were used to pay down Terasen Gas' operating line.

On June 30, 2008, TGVI made a $6.5 million payment on its government loans, of which approximately $3.9 million was refinanced through borrowings under its $20 million non-revolving credit facility and the remaining amount funded with cash on hand.

On December 1, 2008, Terasen repaid the Series 1 Medium-Term Note Debentures using short-term borrowings from Fortis.

To finance the Company's investment in FortisWest preferred shares, Terasen borrowed an additional $150 million from its parent company.

On June 1, 2007 and July 18, 2007, Terasen reduced the capacity of its credit agreement by $270 million and $80 million respectively, to bring the operating limit to $100 million.

On June 30, 2007, TGVI made a $1.4 million payment on its government loans, of which approximately $0.8 million was refinanced through borrowings under its $20 million non-revolving credit facility and the remaining amount funded with cash on hand.

On August 24, 2007, Terasen Gas renegotiated and extended its credit facility for five years with similar terms to the original facility and common for such term credit facilities. The $500 million unsecured committed revolving credit facility is with a syndicate of banks and matures in August 2012. In 2008, under the terms of the agreement, the facility was extended to mature in August 2013.

On October 2, 2007, Terasen Gas issued $250.0 million of Medium-Term Note Debentures at a coupon interest rate of 6.00 per cent. The proceeds were used to repay the current debt maturities that matured during October 2007.

As at December 31, 2008, the Company and its subsidiaries had lines of credit in place totalling $950.0 million to finance cash requirements. The borrowings on these lines are included in short-term notes. These lines enable the respective companies to borrow directly from their bankers, issue bankers' acceptances and support commercial paper issuance. Bank lines of $552.9 million were unutilized at the end of 2008. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the Canadian market at rates generally below bank prime. Terasen does not have, nor does it expect to have, any defaults or arrears.

The Company declared dividends on common shares of $77.0 million during 2008. No dividends on common shares were declared in 2007.

Contractual obligations

The Company's subsidiaries and proportionately consolidated entities have entered into operating leases for certain building space and natural gas transmission and distribution assets. In addition, Terasen Gas and TGVI have entered into gas purchase contracts that represent future purchase obligations. The following table sets forth the Company's operating leases, gas purchase obligations and employee benefit plan contributions due in the years indicated:

In millions of dollars	Operating leases	Purchase obligations	Employee benefit plans	Total
2009	$ 17.4	$ 416.5	$ 10.8	$ 444.7
2010	16.1	26.9	8.5	51.5
2011	15.8	22.8	-	38.6
2012	15.3	-	-	15.3
2013	13.5	-	-	13.5
Thereafter	85.5	-	-	85.5
	$ 163.6	$ 466.2	$ 19.3	$ 649.1

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at December 31, 2008. The employee benefit plan contributions have been estimated up to the date of the next actuarial valuation for each plan unless the valuation falls in the next twelve months, then the Company has provided for an estimate of the contributions. Employee benefit plan contributions beyond the date of the next actuarial valuation cannot be accurately estimated.

In prior years, TGVI received non-interest bearing, repayable loans from the Federal and Provincial governments of $50 million and $25 million respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for property, plant and equipment. The government loans are repayable in any fiscal year after 2002 and prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. In 2006, all of the repayment criteria were met when TGVI obtained additional financing through a new credit agreement. In addition, since the conditions continue to be met (an annual test) TGVI is expected to make a repayment on the loans in 2009 of approximately $8.1 million (2007 - $6.5 million). As the loans are repaid and replaced with non-governmental loans, property, plant and equipment and long-term debt will increase in accordance with the approved capital structure, as will the rate base used in determining rates. The amounts are not included in the obligations in the table above as the amounts and timing of repayments are dependent upon the approved RDDA recovery each year and the ability to replace the loans with non-government subordinated debt financing on reasonable commercial terms.

Financial position

The following table outlines the significant changes in the consolidated balance sheets as at December 31, 2008 compared to December 31, 2007, other than assets and liabilities related to the Petroleum Pipelines businesses that were sold in May 2007.

Balance sheet item	Increase (decrease) ($ millions)	Explanation
Rate stabilization accounts (including current and long-term)	(51.9)	The decrease in the net asset position is mainly due to the fair value mark-to-market for the gas derivatives being lower at December 31, 2008 versus December 31, 2007. Additionally, the company has been collecting higher amounts from customers while gas prices have declined.
Accounts receivable	44.5	The increase in accounts receivable is due to cooler weather and an increase in the commodity cost of gas charged to customers in 2008 compared to 2007.
Short-term notes	48.5	The increase is due to the reclassification of borrowings by TGVI from long-term debt to short-term notes during the year. When TGVI issued its medium-term notes, the credit facility was re-classified to short-term notes to reflect the nature of the borrowings. This is partially offset by the lower borrowings in Terasen Gas due to additional long-term debt issued in the year.
Accounts payable and accrued liabilities	69.8	The increase is mainly due to higher gas cost payable due to cooler weather in the current year compared to the prior year.
Long-term investments	150.0	The Company acquired Series C Preferred Shares of FortisWest Inc., a subsidiary of Fortis Inc., on May 1, 2008.

Working capital

Terasen's working capital requirements fluctuate seasonally based on natural gas consumption. Given the relatively low-risk regulated nature of its business, Terasen is able to maintain negative working capital balances. Terasen maintains adequate committed credit facilities to meet its working capital requirements. On an annual basis, Terasen generates sufficient cash flow to meet its working capital requirements.

Cash flow

It is expected that operating expenses and interest costs will generally be paid out of operating cash flows, with varying levels of residual cash flow available for capital expenditures and/or for dividend payments. Cash required to complete capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Terasen and long-term debt issues.

The Company's ability to service its debt obligations and pay dividends on its common shares is dependent on the financial results of the Company and the related cash payments from these subsidiaries. Cash required to support capital expenditure programs is expected to be derived with borrowings from Fortis. Depending on the timing of cash payments from the subsidiaries, borrowings under the Company's credit facility or from Fortis may be required from time to time to support the servicing of debt and payment of dividends.

The Company does not expect any significant decrease in operating cash flows in 2009, in light of the expected continued downturn in the global economy and, therefore, does not anticipate any difficulty in servicing its debt obligations and paying common dividends. Also, the Company does not anticipate any difficulty in sourcing the cash required to fund the 2009 capital expenditure programs.

Dividend restrictions

As part of its approval of the acquisition of Terasen by KMI, as well as the subsequent sale from KMI to Fortis Inc, the BCUC imposed a number of conditions intended to ring-fence Terasen Gas and TGVI from Terasen. These restrictions included a prohibition on the payment of dividends unless Terasen Gas or TGVI has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. As a result of this and the decision issued by the BCUC on March 2, 2006, Terasen Gas and TGVI must maintain a percentage of common equity to total capital that is at least as much as that determined by the BCUC from time to time for rate-making purposes. In 2008 and 2007, none of these restrictions constrained the distribution of subsidiary earnings not otherwise needed for reinvestment.

Credit ratings

Securities issued by Terasen and Terasen Gas are rated by DBRS Inc. (DBRS) and Moody's Investors Service Inc. (Moody's). The ratings assigned to securities issued by the Terasen group of companies are reviewed by these agencies on an ongoing basis.

The table below summarizes the ratings assigned to the Company's various securities. The DBRS rating for Terasen and Terasen Gas is as of May 20, 2008. The Moody's rating for Terasen is as of July 17, 2008 and for Terasen Gas is as of May 28, 2008.

CREDIT RATINGS

	DBRS	Moody's
Terasen Inc.		
Unsecured long-term debt:	BBB (High)	Baa2
Capital securities	BBBy	Baa3
Terasen Gas Inc.:		
Commercial paper	R-1 (Low)	-
Secured long-term debt	A	A2
Unsecured long-term debt	A	A3
Terasen Gas (Vancouver Island) Inc.:		
Unsecured long-term debt	BBB (High)	A3

During the year, Terasen discontinued its commercial paper rating with DBRS.

In 2004, after reassessing its relationship with Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies (Canada) Corporation (S&P), Terasen discontinued the engagement of S&P to provide credit ratings on the debt of Terasen and Terasen Gas. Terasen believes the credit ratings issued by Moody's and DBRS will be sufficient to service the requirements of creditors and maintain the Company's access to capital. S&P continues to provide an unsolicited rating on Terasen's outstanding debt based on publicly available information. As of December 17, 2008, Terasen's unsecured long-term debt was rated BBB+ and Terasen Gas was rated A by S&P. There is a provision in Terasen's $100 million credit facility that a downgrade of Terasen's unsecured long-term debt rating below BBB (low) or Baa3 by DBRS or Moody's, respectively, would shorten the remaining term of Terasen's credit facility to ten months.

In addition, a downgrade of Terasen Gas below investment grade by any of the major credit rating agencies could trigger margin calls and other cash requirements under Terasen Gas' gas purchase and commodity derivative contracts.

Projected capital expenditures

Terasen has estimated total 2009 consolidated capital expenditures before contributions in aid of construction of $307.7 million. Major capital expenditures in 2009 include construction of the Mt. Hayes Natural Gas Storage Project ($73.7 million), the Gateway Infrastructure Project ($15.5 million), the Fraser River South Bank South Arm (SBSA) Rehabilitation Project ($25.4 million), the review of the potential replacement of the Customer Information System (CIS) ($13.9 million) and the Squamish to Whistler Pipeline Project ($16.3 million).

Mt. Hayes Natural Gas Storage Project

On April 1, 2008, the BCUC provided final approval to construct and operate a natural gas storage facility at Mt. Hayes on Vancouver Island. Once the approval was received, TGVI entered into an Engineering, Procurement and Construction (EPC) contract with a third party. In addition, TGVI entered into a foreign exchange futures contract to mitigate the foreign exchange risk associated with the US dollar portion of the EPC contract. Construction of the facility is now underway and is expected to be fully commissioned by late 2011. Overall, the project is projected to cost approximately $200.0 million to complete.

Gateway Infrastructure Project

As the result of the Provincial government's Gateway initiative, a regional infrastructure program to improve the movement of people, goods and transit throughout Greater Vancouver, Terasen Gas will be required to relocate some of its pipeline system. Total anticipated spending for the project expected to be fully recoverable is approximately $30.0 million with $15.5 million estimated for 2009.

Fraser River SBSA Rehabilitation Project

Terasen Gas filed a CPCN application in the fourth quarter of 2008 requesting approval to perform extensive rehabilitation of the current 20-inch and 24-inch underwater transmission pipeline crossings of the south arm of the Fraser River serving Vancouver and Richmond. Terasen Gas expects to receive approval for this project in early 2009 with completion anticipated to be in 2010.

Customer Information System Project

The Company is currently conducting a review of the existing customer care services arrangements with its outsourced provider to ensure the needs of customers will be met in the future. Later in 2009, the Company expects to file a CPCN application requesting approval and funding for the development of a replacement CIS system with spending in 2009 estimated to be $13.9 million.

Whistler Pipeline Project

TGVI's construction of the 50-kilometre pipeline lateral from Squamish to Whistler continues and, as at the end of December 2008, approximately 49 kilometres of the pipeline had been constructed. Originally scheduled to be completed by summer 2008, the pipeline lateral is now expected to be completed in April 2009. Upon completion of the pipeline, the Company will convert the Resort Municipality of Whistler from propane to natural gas during the spring and summer of 2009. TGW expects that the overall cost of the conversion to be up to $4 million above the costs currently approved for recovery by the BCUC due to a higher number of appliances to convert, higher labour rates and longer duration. The Company is assessing the impact of this cost overrun, as well as mitigating options with respect to managing the expected conversion cost increase.

The Company expects to finance capital expenditures in 2009 with a combination of proceeds from shareholder advances, short and long-term borrowings and internally generated funds.

Off-balance sheet arrangements

There are no material off-balance sheet arrangements.

Transactions with related parties

The Company's current parent company Fortis Inc. provided corporate management services totalling approximately $4.3 million (2007 - $5.0 million) provided by Fortis Inc. and former parent company, Kinder Morgan Inc. for the year ended December 31, 2008.

The Company was charged interest of approximately $11.6 million (2007 - $3.7 million) during the year ended December 31, 2008 by Fortis Inc. on the borrowings from the parent company including borrowings for the purchase of the FortisWest shares. The amount due to parent company is unsecured and due on demand and accrues interest at a bankers acceptance rate plus twenty five basis points.

On May 1, 2008, the Company borrowed $150.0 million from its parent company, Fortis Inc. The proceeds were used to purchase 6,000,000 Series C Preferred Shares (Shares) of FortisWest, a subsidiary of Fortis Inc. The Shares entitle the Company to a fixed preferential cumulative cash dividend at a rate of 6.75 per cent annually with dividends paid quarterly. The interest is also paid quarterly and the advance is due on demand and secured by a pledge of the Shares. For the period from May 1, 2008 to December 31, 2008 the Company paid interest of $6.5 million to Fortis Inc. on the demand loan and the Company received dividends from FortisWest of $6.7 million on the Shares.

The Company's parent, Fortis Inc., grants stock options to certain employees of the Company under its stock option plans. For the year ended December 31, 2008, the Company was charged, and recorded an expense of $0.3 million (2007 - $0.1 million) for the fair value of the stock compensation granted by Fortis Inc.

Related party transactions are recorded at the exchange amount.

Changes in accounting policies

Effective January 1, 2008, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants (CICA).

a) Section 3862, *Financial Instruments—Disclosures*, and Section 3863, *Financial Instruments—Presentation*, requires disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed.
b) Section 1535, *Capital Disclosures*, requires the Company to disclose additional information about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding the Company's objectives, policies and processes for managing capital.
c) Section 3031, *Inventories*, requires inventories to be measured at the lower of cost or net realizable value, disallows the use of a last-in first-out inventory costing methodology, and requires that, when circumstances that previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This standard is to be applied retrospectively. As at January 1, 2008, supplies and other inventories of $8.2 million ($7.6 million as at January 1, 2007) were reclassified to property, plant and equipment

from inventory on the balance sheet as they are held for the development, construction, maintenance and repair of other property, plant and equipment. During the year ended December 31, 2008, gas in storage inventories of $1,267.8 million (2007 - $1,128.6 million) were expensed and reported in cost of natural gas on the consolidated statement of earnings and comprehensive earnings.

Future accounting pronouncements

International Financial Reporting Standards (IFRS): In February 2008, the Accounting Standards Board (AcSB) confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an IFRS Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011.

On June 27, 2008, the Canadian Securities Administrators (CSA) issued Staff Notice 52-321, Early Adoption of IFRS, which indicated that the CSA would be prepared to grant an exemption to allow Canadian financial statement issuers to adopt IFRS early on a case-by-case basis, provided that they could demonstrate that they met certain conditions. Terasen is not planning to adopt IFRS early.

The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section - *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to the IFRS Omnibus Exposure Draft.

Terasen is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Terasen does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required, as well as systems changes that may be necessary to gather and process the required information.

Terasen commenced its IFRS conversion project in 2007 and has established a formal project governance structure that includes the audit committees, senior management and a project team. Overall project governance, management and support is coordinated by Fortis. Regular reporting occurs to the Audit Committee of the Board of Directors. An external expert advisor has been engaged to assist in the IFRS conversion project.

The Terasen IFRS conversion project consists of three phases: Scoping and Diagnostics, Analysis and Development, and Implementation and Review.

Phase One: Scoping and Diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, has been completed. The resulting identified areas of accounting difference of highest potential impact to the Company, based on existing IFRS, are rate-regulated accounting, property, plant and equipment, provisions and contingent liabilities, employee benefits, impairment of assets, income taxes, and initial adoption of IFRS under the provisions of IFRS 1 *First-Time Adoption of IFRS*.

Phase Two: Analysis and Development is nearing completion, and involves detailed diagnostics and evaluation of the financial impacts of various options and alternative methodologies provided for under IFRS; identification and design of operational and financial business processes; initial staff and audit committee training; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application upon transition to IFRS; summarization of 2011 IFRS disclosure requirements; and development of required solutions to address identified issues.

It is anticipated that the adoption of IFRS will have an impact on information systems requirements. The Company is assessing the need for system upgrades or modifications to ensure an efficient conversion to IFRS. As part of Phase Two, information systems plans are being prepared for implementation in Phase Three. The extent of the impact on the Company's information systems is not reasonably determinable at this time.

Phase Three: Implementation and Review, expected to commence mid-year 2009, will involve the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and further training programs across the Company's finance and other affected areas, as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS in business processes; and, audit committee approval of IFRS compliant financial statements.

Terasen will continue to review all proposed and continuing projects of the IASB, particularly the project on rate-regulated activities that was recently added to the IASB's technical agenda, and proposed amendments to IFRS 1 for entities with operations subject to rate regulation, and will participate in any related processes as appropriate.

Rate-regulated operations: In March 2007, the AcSB issued an Exposure Draft on rate-regulated operations that proposed: (i) the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, of the CICA Handbook providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation be removed; (ii) the explicit guidance for rate-regulated operations provided in Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*, be removed; and (iii) Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation*, be retained as is.

The AcSB has also observed that relying on US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71), as another source of Canadian GAAP in the absence of CICA Handbook guidance addressing the specific circumstances of entities subject to rate regulation, is consistent with Section 1100 when the qualifying criteria of FAS 71 are met.

In August 2007, the AcSB issued a Decision Summary on the Exposure Draft that supported the removal of the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, and the amendment to Section 3465, *Income Taxes*, to recognize future income tax liabilities and assets, as well as an offsetting regulatory asset or liabilities for entities subject to rate regulation. Both changes will apply prospectively for fiscal years beginning on or after January 1, 2009. It was also decided that the current guidance pertaining to property, plant and equipment, disposal of long-lived assets and discontinued operations, and consolidated financial statements be maintained and that the existing AcG-19 will not be withdrawn from the Handbook but that the guidance will be updated as a result of the other changes. The AcSB also decided that the final Background Information and Basis for Conclusions associated with its rate regulation project would not express any views of the AcSB regarding the status of US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, as an "other source of GAAP" within the Canadian GAAP hierarchy.

Effective January 1, 2009, the impact on the Company of the amendment to Section 3465, *Income Taxes*, will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to or recovered from customers in future gas rates. Currently, the Company uses the taxes payable method of accounting for income taxes on regulated earnings. The estimated effect on the Company's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2008, would have been an increase in future tax liabilities of $321.3 million, including those associated with income taxes that will become payable on future revenues as they are collected from customers when the tax timing differences reverse. There would also be a corresponding increase in regulatory assets. Terasen is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate-regulated operations.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Company must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, 3061, 3465, and 3475. All assets and liabilities arising from rate regulation do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, Financial Statement Concepts. These assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Company's consolidated financial statements if it had adopted the removal of the temporary exemption in Section 1100, for the year ended December 31, 2008. Terasen is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate-regulated operations.

Effective January 1, 2009, the Company will be adopting the new CICA Handbook Section 3064, *Goodwill and Intangible Assets,* which converges Canadian GAAP for goodwill and intangible assets with IFRS. The new standard provides for more comprehensive guidance on intangible assets, in particular for internally developed intangible assets. The Company is still assessing the financial reporting impact of adopting this standard.

Financial and other instruments

FAIR VALUE ESTIMATES

	December 31, 2008		December 31, 2007	
In millions of dollars	**Carrying value**	**Estimated fair value**	Carrying value	Estimated fair value
Held in trading				
Cash and short-term investments[1]	**$ 33.0**	**$ 33.0**	$ 17.8	$ 17.8
Loans and receivables				
Accounts receivable[1,2]	**392.9**	**392.9**	348.4	348.4
Long-term receivable[1,2]	**9.1**	**9.1**	9.2	9.2
Other financial liabilities				
Short-term notes[2]	**353.5**	**353.5**	305.0	305.0
Accounts payable and accrued liabilities[2]	**455.0**	**455.0**	385.2	385.2
Due to parent company[2]	**470.3**	**470.3**	135.3	135.3
Long-term debt, including current portion[4,5,6]	**1,920.1**	**1,959.2**	2,144.3	2,356.4

1 Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.

2 Carrying value approximates amortized cost.

3 The fair market value is not readily available.

4 Carrying value is measured at amortized cost using the effective interest rate method.

5 Carrying value at December 31, 2008 is net of unamortized deferred financing costs of $15.6 million (2007 - $12.3 million). On January 1, 2007, deferred financing costs were reclassified from other assets in accordance with the transitional provisions of CICA Section 3855. The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

6 Fair value is calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2008, or by using available quoted market prices.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

Derivative instruments

The Company hedges its exposure to fluctuations in natural gas prices and foreign exchange rates through the use of derivative instruments. The table below indicates the valuation of the derivative instruments as at December 31, 2008.

ASSET (LIABILITY)

			December 31, 2008		December 31, 2007	
In millions of dollars	Number of swaps and options	Term to maturity (years)	**Carrying value**	**Fair value**	Carrying value	Fair value
Foreign exchange forward contract:						
TGVI	1	3	**$ 7.4**	**$ 7.4**	$ -	$ -
Terasen Gas and TGVI[1]:						
Natural gas commodity swaps	228	Up to 3	**$ (84.2)**	**$ (84.2)**	$ (79.4)	(79.4)
Gas purchase contract premiums	74	Less than 3	**(7.6)**	**(7.6)**	5.2	5.2

1 The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates. The natural gas derivatives fair values have been determined using published market prices for natural gas commodities. The gains and losses associated with natural gas derivatives are recorded in deferral accounts, subject to regulatory approval, and passed through to customers in future rates.

Outstanding share data

February 4, 2009	
Common shares issued and outstanding	17,037,853
8.0% capital securities issued and outstanding	$125,000,000

Terasen is a direct wholly-owned subsidiary of Fortis Inc. At December 31, 2008, all of the common shares of the Company are owned by Fortis Inc.

The 8.0 per cent capital securities are exchangeable on or after April 19, 2010 for common shares of the Company at 90 per cent of the market price, subject to the right of the Company to redeem the securities for cash. A maximum of 125,000,000 common shares could be issued if this right was exercised.

Additional information

Additional information relating to Terasen Inc. is available on SEDAR at www.sedar.com.

Consolidated financial statements

Years ended December 31, 2008 and 2007

Management's report

Financial reporting

Management is responsible for the accompanying consolidated financial statements. These financial statements have been prepared in conformity with Canadian generally accepted accounting principles and, where appropriate, include amounts that are based on management's best estimates and judgments.

The Board of Directors, through its Audit Committee, oversees Management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the consolidated financial statements for issuance to the shareholder.

Internal control over financial reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to the Company's Management regarding the preparation and presentation of the consolidated financial statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's independent auditors, Ernst and Young LLP, conducted their audits in accordance with Canadian generally accepted auditing standards. Their report outlines the scope of their audits and gives their opinion on the consolidated financial statements.

Signed: R.L. (Randy) Jespersen
President and CEO

Signed: Scott A. Thomson
Vice President, Regulatory Affairs
and Chief Financial Officer

Vancouver, Canada,
February 3, 2009

Auditors' report

To the Shareholder of

Terasen Inc.

We have audited the consolidated balance sheets of Terasen Inc. as at December 31, 2008 and 2007 and the consolidated statements of earnings (loss) and comprehensive earnings (loss), deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Vancouver, Canada,
January 30, 2009

Ernst & Young LLP
Chartered Accountants

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) AND COMPREHENSIVE EARNINGS (LOSS)

In millions of dollars *Years ended December 31*	**2008**	2007
Revenues		
Natural gas transmission and distribution	**$ 1,905.2**	$ 1,750.8
Other activities (Note 16)	**16.3**	17.7
	1,921.5	1,768.5
Expenses		
Cost of natural gas	**1,267.8**	1,128.6
Cost of revenues from other activities	**0.2**	8.0
Operation and maintenance	**204.2**	197.8
Depreciation and amortization	**104.0**	99.7
Property and other taxes	**53.5**	53.3
	1,629.7	1,487.4
Operating income	**291.8**	281.1
Financing costs (Note 13 and 16)	**167.5**	222.5
Gain on sale of property, plant and equipment	**-**	(8.2)
Earnings before income taxes and discontinued operations	**124.3**	66.8
Income tax expense (Note 14)	**22.6**	30.4
Earnings before discontinued operations	**101.7**	36.4
Discontinued operations, net of income taxes (Note 4)	**-**	(410.2)
Net earnings (loss) and comprehensive earnings (loss)	**$ 101.7**	$ (373.8)

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF DEFICIT

In millions of dollars *Years ended December 31*	**2008**	2007
Deficit, beginning of year	**$ (1,538.5)**	$ (669.0)
Adjustment to deficit (Note 2)	**-**	35.5
	(1,538.5)	(633.5)
Charge to deficit related to the disposal of the Pipelines businesses to affiliated companies (Note 4)	**-**	(531.2)
Net earnings (loss) and comprehensive earnings (loss)	**101.7**	(373.8)
	(1,436.8)	(1,538.5)
Dividend on common shares	**(77.0)**	-
Deficit, end of year	**$ (1,513.8)**	$ (1,538.5)

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

In millions of dollars *As at December 31*	2008	2007
Assets		
Current assets:		
Cash and short-term investments	$ **33.0**	$ 17.8
Accounts receivable	**392.9**	348.4
Inventories of gas in storage and supplies	**211.6**	194.9
Prepaid expenses	**3.4**	6.0
Current portion of rate stabilization accounts (Note 7)	**76.5**	78.3
	717.4	645.4
Property, plant and equipment (Note 6)	**2,985.2**	2,852.3
Long-term investment (Note 16)	**150.0**	-
Goodwill (Note 2)	**818.1**	824.1
Rate stabilization accounts (Note 7)	**-**	18.7
Future income taxes (Note 14)	**12.1**	13.1
Other assets (Note 8)	**75.8**	71.5
	$ **4,758.6**	$ 4,425.1
Liabilities and Shareholder's equity		
Current liabilities:		
Short-term notes	$ **353.5**	$ 305.0
Accounts payable and accrued liabilities	**455.0**	385.2
Income and other taxes payable	**84.0**	47.4
Current portion of rate stabilization accounts (Note 7)	**23.7**	-
Current portion of long-term debt (Note 9)	**78.5**	470.6
Due to parent company (Note 16)	**470.3**	135.3
	1,465.0	1,343.5
Long-term debt (Note 9)	**1,841.6**	1,673.7
Rate stabilization accounts (Note 7)	**7.7**	-
Other long-term liabilities and deferred credits (Note 10)	**212.0**	200.3
	3,526.3	3,217.5
Shareholder's equity:		
Common shares (Note 11)	**1,475.3**	1,475.3
Preferred shares (Note 11)	**1,179.8**	1,179.8
Contributed surplus (Note 11)	**91.0**	91.0
Deficit	**(1,513.8)**	(1,538.5)
	1,232.3	1,207.6
	$ **4,758.6**	$ 4,425.1

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board:

Signed: R.L. (Randy) Jespersen Director

Signed: Harold Calla, Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions of dollars *Years ended December 31*	2008	2007
Cash flows provided by (used for)		
Operating activities		
Earnings before discontinued operations	$ 101.7	$ 36.4
Adjustments for non-cash items:		
Depreciation and amortization	104.0	99.7
Future income taxes	1.0	1.5
Gain on sale of property, plant and equipment	-	(8.2)
Other	(5.7)	(6.4)
	201.0	123.0
Changes in working capital	54.5	(9.5)
	255.5	113.5
Investing activities		
Property, plant and equipment	(213.0)	(174.6)
Disposal of discontinued operations, net of cash disposed (Note 4)	-	(163.2)
Long-term investment	(150.0)	-
Proceeds from sale of land	14.1	-
Other assets and deferred credits	34.4	31.6
	(314.5)	(306.2)
Financing activities		
Increase (decrease) in short-term notes	48.5	(26.0)
Increase in long-term debt	500.0	287.6
Reduction of long-term debt	(732.3)	(250.0)
Advances from parent company	335.0	135.3
Change in contributed surplus for capital contribution (Note 1)	-	52.4
Dividends on common shares	(77.0)	-
	74.2	199.3
Net increase in cash	15.2	6.6
Cash and short-term investments at beginning of year	17.8	11.2
Cash and short-term investments at end of year	$ 33.0	$ 17.8
Supplemental cash flow information:		
Interest paid in the year	$ 166.2	$ 237.9
Income taxes paid in the year	12.5	103.4
Non-cash transactions: Mark-to-market on certain gas derivatives deferred in rate-stabilization accounts	17.6	(65.6)
Settlement of accounts payable and accrued liabilities and subordinated debt through issuance of common and preferred shares	-	2,563.9
Settlement of intercompany payable as a contribution to capital	-	19.7
Government loan capitalized in property, plant and equipment	8.1	6.5
Property, plant and equipment purchases included in accounts payable and accrued liabilities	11.3	(1.4)
Net non-cash proceeds arising on the sale of property	-	8.2
Mark-to-market on foreign exchange forward deferred in other long-term liabilities and deferred credits	7.4	-

Cash is defined as cash and short-term investments.
The accompanying notes are an integral part of these consolidated financial statements.

Notes to consolidated statements of financial statements

(Tabular amounts in millions of dollars, except where stated otherwise)
Years ended December 31, 2008 and 2007

Terasen Inc. (Terasen or the Company) provides energy transportation and utility asset management services. Terasen operated in two primary business segments which were separately managed to assess operational performance.

a) Natural gas transmission and distribution operations involve the transmission and distribution of natural gas and propane for residential, commercial, institutional, and industrial customers in British Columbia. The operations are conducted through Terasen Gas Inc. (Terasen Gas), serving the Lower Mainland and Interior of British Columbia; Terasen Gas (Vancouver Island) Inc. (TGVI), serving Vancouver Island and the Sunshine Coast; and Terasen Gas (Whistler) Inc. (TGW).

b) Petroleum transportation operations were carried out through Terasen Pipelines (Trans Mountain) Inc. (Trans Mountain), which owned and operated a common carrier pipeline system for crude and refined petroleum products transported from Edmonton, Alberta to Vancouver, British Columbia and Washington State; Terasen Pipelines (Corridor) Inc. (Corridor), which owned a pipeline in northern Alberta transporting diluted bitumen; and the one-third owned entities Express Pipeline LP and Express US Holdings LP (the Express System). The Express System transported crude oil from Hardisty, Alberta, through the Rocky Mountain region of the United States and on to Wood River, Illinois. These operations were sold in 2007 and are classified as discontinued operations at December 31, 2007 as described in Note 4.

c) Other activities include international consulting activities, the Company's 30 per cent interest in CustomerWorks LP (CWLP), Terasen Energy Services (TES) and corporate financing costs and administration charges.

On February 26, 2007, Knight Inc. (formerly known as Kinder Morgan, Inc.) (KMI), the Company's former parent announced that it had entered into a definitive agreement with Fortis Inc. to sell Terasen and its principal natural gas transmission and distribution assets, including its subsidiaries Terasen Gas and Terasen Gas (Vancouver Island) Inc. as well as other activities including Terasen Energy Services. The sale did not include the petroleum transportation subsidiaries nor investments under the Kinder Morgan Canada name. The purchase price of approximately $3.7 billion included the assumption of approximately $2.4 billion of debt. The transaction closed on May 17, 2007. The Company has classified its petroleum transportation operations income and cash flow as discontinued. The Company converted any accrued interest and inter-company payables into equity and recorded this as contributed surplus.

1. Amalgamation

On February 16, 2007, Terasen was amalgamated with Terasen Pipelines (Trans Mountain) Inc. and 0731297 BC Ltd. under the name "Terasen Inc." which is the Company represented in these financial statements. 0731297 BC Ltd. was the direct parent of Terasen Inc. prior to the amalgamation and acquired the shares of Terasen as part of the KMI acquisition of Terasen on November 30, 2005. It is the amalgamated corporation that is represented in the Terasen consolidated financial statements as at December 31, 2008 and for the years ended December 31, 2008 and 2007. Post-amalgamation Terasen continued to own all the assets it owned immediately prior to the amalgamation including the gas distribution business operated by Terasen Gas.

As a result of this amalgamation, the Terasen consolidated financial statements as at December 31, 2006 and for the years ended December 31, 2006 and 2005 do not reflect the same entity as, and are not directly comparable with the consolidated financial statements shown in this document as at December 31, 2007 and for the year ended December 31, 2007 that relate to the amalgamated corporation.

PURCHASE COST

	(millions)
Shares of KMI issued	$ 1,338.7
Debt issued	2,491.3
Transaction costs	18.5
	$ 3,848.5

In accordance with the purchase method of accounting, the purchase cost was allocated to the underlying assets acquired and liabilities assumed based primarily upon their estimated fair values at the date of acquisition. The estimated fair values were based on a combination of independent appraisals and internal estimates. The excess of purchase cost over the net identifiable tangible and intangible assets acquired represents goodwill. The goodwill is not deductible for tax purposes. The purchase cost and purchase price allocation are summarized in the following table:

PURCHASE PRICE ALLOCATION

	(millions)
Current assets	$ 788.5
Property, plant and equipment	4,244.1
Investment in Express	455.5
Rate stabilization—long-term	51.5
Other assets	93.2
Goodwill	2,271.6
Current liabilities	(1,581.7)
Long-term debt and debentures	(2,060.6)
Long-term liabilities	(163.1)
Future income taxes	(250.5)
	$ 3,848.5

During the fourth quarter of 2008, Terasen Gas recognized the benefit of certain tax loss carry forwards which were restricted when KMI acquired the Company in 2005. The benefit of these tax loss carry forwards were recognized within Terasen Gas. Goodwill has been adjusted by $6.0 million for the benefit of these loss carry forwards.

2. Significant accounting policies

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses in the financial statements, as well as the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and reflect the following summary of significant accounting policies.

Basis of presentation

The consolidated financial statements include the accounts of the Company, its subsidiaries, and its proportionate share of the accounts of jointly-controlled entities. Investments in entities that are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method.

Certain of the prior year comparative figures have been reclassified to conform with the current year's presentation.

Changes in accounting policies

Effective January 1, 2008, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants (CICA).

a) Section 3862, *Financial Instruments—Disclosures*, and Section 3863, *Financial Instruments—Presentation*, require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed. The new disclosures are included in Note 15.

b) Section 1535, *Capital Disclosures*, requires the Company to disclose additional information about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding the Company's objectives, policies and processes for managing capital. The new disclosures are in Note 15.

c) Section 3031, *Inventories*, requires inventories to be measured at the lower of cost or net realizable value, disallows the use of a last-in first-out inventory costing methodology, and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This standard is to be applied retrospectively. As at January 1, 2008, supplies and other inventories of $8.2 million ($7.6 million as at January 1, 2007) were reclassified to property, plant and equipment from inventory on the balance sheet as they are held for the development, construction, maintenance and repair of other property, plant and equipment. During the year ended December 31, 2008, gas in storage inventories of $1,267.8 million (2007 - $1,128.6 million) were expensed and reported in cost of natural gas on the consolidated statement of earnings (loss) and comprehensive earnings (loss).

Financial instruments

The Company utilizes derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange, interest rates and energy commodity prices.

a) Section 3855, *Financial Instruments—Recognition and Measurement*, prescribes the criteria for recognition and presentation of financial instruments on the balance sheet and the measurement of financial instruments according to prescribed classifications. This section also addresses how financial instruments are measured subsequent to initial recognition and how the gains and losses are recognized.

   The Company is required to designate its financial instruments into one of the following five categories: held for trading; available for sale; held to maturity; loans and receivables; and other financial liabilities. All financial instruments are to be initially measured at fair value.

Financial instruments classified as held for trading or available for sale are subsequently measured at fair value with any change in fair value recorded in net earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

All derivative financial instruments are recorded on the balance sheet at fair value. Mark-to-market adjustments on these instruments are included in net earnings, unless the instruments are designated as part of a cash flow hedge relationship, and then the effective portion of changes in fair value are recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in net earnings. For the rate regulated operations, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates, is subject to regulatory deferral treatment to be recovered from or refunded to customers in future rates.

In accordance with the standard's transitional provisions, the Company recognizes as separate assets and liabilities only embedded derivatives acquired or substantively modified on or after January 1, 2003.

The Company has designated its financial instruments as follows:

- Cash and short-term investments are classified as "Held for Trading" and are recorded at fair value. Due to the relatively short period to maturity of these financial instruments the carrying values approximate their fair values.
- Accounts receivable and long-term receivables are classified as "Loans and Receivables." These financial assets are recorded at values that approximate their amortized cost using the effective interest method.
- Short-term notes, accounts payable and accrued liabilities, due to parent company, long-term debt and related issue costs are classified as "Other Financial Liabilities." These financial liabilities are recorded at values that approximate their amortized cost using the effective interest method.

Deferred financing costs will be taken into earnings using the effective interest method over the life of the related debt. Prior to January 1, 2007, deferred financing costs were amortized using the straight-line method of amortization. As allowed by the standard, a one-time adjustment of $1.7 million has been made to retained earnings to reflect the difference between the straight-line method and the effective interest method of amortization prior to January 1, 2007.

The Company recognizes transaction costs associated with financial assets and liabilities, that are classified as other than held for trading, as an adjustment to the cost of those financial assets and liabilities recorded on the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument.

b) Section 1530, *Comprehensive Income*, requires the presentation of a statement of comprehensive income and provides guidance for the reporting and display of other comprehensive income. Comprehensive income represents the change in equity of an enterprise during a period from transactions and other events arising from non-owner sources including gains and losses arising on translation of self-sustaining foreign operations, gains and losses from changes in fair value of available for sale financial assets and changes in fair value of the effective portion of cash flow hedging instruments. The Company has not recognized any adjustments through other comprehensive income for the years ended December 31, 2008 and 2007.

c) Section 3865, *Hedges,* specifies the criteria under which hedge accounting may be applied, how hedge accounting should be performed under permitted hedging strategies and the required disclosures. The Company's cash flow hedges are for the purchase of natural gas. Given that the Company is subject to rate regulation, the ineffective portion of changes in the fair value of these hedges is deferred as an asset or liability until it is settled, offset by an asset or liability on behalf of customers. Upon settlement, the recognized gain or loss is recorded as a regulatory asset or liability and is collected from or refunded to ratepayers in subsequent periods. The Company recognized an additional liability of $1.1 million to counterparties for unrealized losses related to gas purchase hedges at January 1, 2007 and an amount recoverable from ratepayers of $1.1 million. Amounts recoverable from ratepayers are recorded in rate stabilization accounts.

The Company utilizes cash flow hedges to hedge the variability in interest payments on the underlying debt instruments. Cash flow hedges for rate-regulated businesses are recorded in Other assets with the offset to Other long-term liabilities and deferred credits while the non-regulated cash flow hedges are recorded in Other assets and Long-term debt. The adoption of this new standard on January 1, 2007 increased Other assets by $0.9 million, increased Long-term debt by $0.1 million and increased Other long-term liabilities and deferred credits by $0.8 million.

Under the Canadian standard prior to January 1, 2007, certain equity investees of the Company had designated future US dollar revenues as a hedge of the foreign currency risk associated with US dollar debt. The investees defer the exchange gains and losses on the US dollar long-term debt and recognize an adjustment to the related revenues at the time the revenue is earned. These arrangements do not qualify for hedge accounting under the new Canadian standard. Accordingly, the Company recorded a one-time adjustment of $38.6 million to the value of its investment offset by an increase of $4.8 million of future income taxes for a net adjustment to retained earnings of $33.8 million.

Foreign currency translation

The Company's former US-based petroleum transportation operations are integrated and were translated into Canadian dollars using the temporal method. Under this method, monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Non-monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect on the dates the assets were acquired or liabilities assumed. Revenues and expenses are translated at the average rates of exchange prevailing during the month the transactions occurred. Under this method, exchange gains and losses on translation are reflected in income when incurred.

Regulation

The natural gas transmission and distribution companies are subject to the regulation of the British Columbia Utilities Commission (BCUC), an independent regulatory authority. Both Terasen Gas and TGVI have multi-year agreements that expire at the end of 2009. These multi-year agreements are cost-of-service based agreements with allowed rates of return on approved rate base set by the BCUC. For 2008, the allowed ROE for Terasen Gas was 8.62 per cent (2007 - 8.37 per cent) and for TGVI was 9.32 per cent (2007 - 9.07 per cent). The allowed rates of return are based on a notional debt-equity ratio of 64.99 per cent debt and 35.01 per cent equity for Terasen Gas and 60 per cent debt and 40 per cent equity for TGVI. The entities have annual review processes for rate approvals, and the allowed rates of return are reset annually unless directed differently by the BCUC. For 2009, the allowed ROE has been set at 8.47 per cent for Terasen Gas and 9.17 per cent for TGVI.

The Trans Mountain and Express System operations were governed by contractual arrangements with shippers and were regulated in Canada by the National Energy Board and, in the United States, tariff matters are regulated by the Federal Energy Regulatory Commission. Both of these regulatory authorities are independent bodies.

Corridor's operations were governed by contractual arrangements with shippers and were subject to regulation by the Alberta Energy and Utilities Board (AEUB), an independent regulatory authority. Corridor's rates were cost-of-service based and determined using formulas embedded in agreements with shippers.

Over 95 per cent of the Company's operations are subject to rate regulation by independent regulatory agencies. These regulatory authorities exercise statutory authority over such matters as rates of return, construction and operation of facilities, accounting practices, rates and tolls, and contractual agreements with customers. Rates are bundled to include transmission and distribution services, where applicable.

In order to recognize the economic effects of regulation, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under GAAP for non-regulated businesses.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in other assets whereas current regulatory assets are rate stabilization accounts which are recorded as current portion of rate stabilization accounts. Regulatory liabilities are recorded in other long-term liabilities and deferred credits.

The impacts of rate regulation on the Company's operations for the twelve months ending December 31, 2008 and 2007 and as at December 31, 2008 and 2007 are described in these Significant Accounting Policies, and in Note 6 "Property, plant and equipment," Note 7 "Rate stabilization accounts," Note 8 "Other assets," Note 10 "Other long-term liabilities and deferred credits," Note 12 "Employee benefit plans," Note 13 "Financing costs," and Note 14 "Income taxes."

Inventories

Inventories of gas in storage are valued at weighted-average cost. The cost of gas in storage is recovered from customers in future rates.

Long-term investments

Investments in entities, when the Company exercises significant influence on their activities, are accounted for under the equity method and are presented in long-term investments in the consolidated balance sheets. Long-term investments in non-quoted equity instruments where the Company does not have significant influence are carried at cost and are presented in long-term investments in the consolidated balance sheets.

When the carrying value exceeds the fair value and the decline in fair value is other than temporary, long-term investments are written-down to their fair value.

Property, plant and equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures for system expansions, betterments and replacements, an allocation of overhead costs and an allowance for funds used during construction. When allowed by the regulators, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

Depreciation of regulated assets is recorded on a straight-line basis over their useful lives. Depreciation rates for regulated assets are approved by the respective regulators, and for non-regulated assets require the use of management estimates of the useful lives of assets. Depreciation of non-regulated equipment is recorded using the declining balance method.

The cost of regulated depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation, as is any gain or loss incurred on disposal.

Impairment of long-lived assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. There was no impairment of long-lived assets for the years ended December 31, 2008 and 2007.

Asset retirement obligations

The Company will recognize the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Company will concurrently recognize a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset. The fair value of the asset retirement obligation is to be estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

Changes in the obligation due to the passage of time are to be recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are to be recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Company's natural gas transmission and distribution and petroleum transportation systems are not currently determinable, the Company has not recognized an asset retirement obligation as at December 31, 2008 and 2007. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates or tolls.

Rate stabilization accounts

TGVI maintains a BCUC approved Revenue Deficiency Deferral Account (RDDA) to accumulate unrecovered costs of providing service to customers or to drawdown such costs where earnings exceed an allowed return as set by the BCUC. The RDDA has accumulated the allowed earnings in excess of achieved earnings prior to 2003 and is to be recovered through future rates.

Terasen Gas is authorized by the BCUC to maintain rate stabilization accounts that mitigate the effect on its earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility. The Revenue Stabilization Adjustment Mechanism (RSAM) accumulates the margin impact of variations in the actual versus forecast volume use for residential and commercial customers.

The Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA) accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in rates. The two accounts segregate costs that are allocable to all sales customers (MCRA) and all residential customers and certain commercial and industrial customers for whom Terasen Gas acquires gas supply (CCRA). TGVI has a Gas Cost Variance Account (GCVA) that mitigates the effect on its earnings of natural gas cost volatility. The GCVA is recoverable in rates from customers in TGVI's service areas in future periods. All rate stabilization account balances for both TGVI and Terasen Gas are amortized and recovered through rates as approved by the BCUC.

Deferred charges

The Company defers certain costs that the regulatory authorities or contractual arrangements require or permit to be recovered through future rates or tolls. Deferred charges are amortized over various periods as approved by the regulator and depending on the nature of the costs.

Deferred charges not subject to regulation relate to projects that are expected to benefit future periods and will be capitalized on completion, expensed on project abandonment, or amortized over their useful lives.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment. The Company is required to perform an annual impairment test and any impairment provision is charged to earnings. To assess for impairment, the fair value of each of the Company's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit, to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. In addition to the annual impairment test, the Company also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No goodwill impairment provision has been determined for the year ended December 31, 2008.

Revenue recognition

The Company recognizes revenues when products have been delivered or services have been performed.

The natural gas transmission and distribution utilities record revenues from natural gas sales on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year and are adjusted for the RSAM and other BCUC approved orders.

For the petroleum transportation operations, revenues are recorded when products are delivered and adjusted according to terms prescribed by toll settlements with the shippers and approved by the respective regulator.

Post-employment benefit plans

The Company sponsors a number of employee benefit plans. These plans include both defined benefit and defined contribution pension plans, and various other post-retirement benefit plans.

The cost of pensions and other post-retirement benefits earned by employees is actuarially determined as the employee provides service. The Company uses the projected benefit method based on years of service and management's best estimates of expected returns on plan assets, salary escalation, retirement age of employees, mortality and expected future health-care costs. The discount rate used to value liabilities is based on AA Corporate bond yields. The Company accrues the cost of defined benefit pensions and post-employment benefits as the employee provides services, except when the regulator requires costs to be expensed as paid.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets as of December 31, 2008 is calculated as the average of the market value of invested assets at December 31, 2008 and two actuarially determined extrapolated market values of invested assets at December 31, 2008. The two extrapolated market values are calculated by using the market value of invested assets at December 31, 2006 rolled forward to December 31, 2008 using 2007 and 2008 net contributions and assumed investment returns, and the market value of invested assets at December 31, 2007 rolled forward to December 31, 2008 using 2008 net contributions and assumed investment returns. These three amounts are then averaged to determine the market-related value of plan assets used in calculating net benefit expense. Additionally, the Company compares the average market-related value to the underlying market value at the end of the period. If the difference between the average market-related value and the actual market value is greater or less than 20 per cent of the actual market value, then any difference is amortized over the expected average remaining service life of the employee group covered by the plan.

Adjustments, in excess of 10 per cent of the greater of the accrued benefit obligation and plan asset fair value, that result from plan amendments, changes in assumptions and experience gains and losses, are amortized over the expected average remaining service life of the employee group covered by the plan. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

Defined contribution plan costs are expensed by the Company as contributions are payable.

Income taxes

The Company's natural gas transmission and distribution-regulated operations account for and recover income tax expense in rates as prescribed by their regulator. This includes accounting for income taxes by the taxes payable method and accounting for certain deferral and rate stabilization accounts on a net of realized tax basis. Therefore, future income taxes related to temporary differences are not recorded.

The taxes payable method is followed as there is a reasonable expectation that all future income taxes will be recovered in rates when they become payable.

The Company's non-regulated operations follow the asset and liability method of accounting for income taxes. Future income tax assets and liabilities are determined based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured at the tax rate that is expected to apply when the temporary differences reverse.

Variable interest entities

The Company has performed a review of the entities with whom it conducts business and has concluded that there are no entities that are required to be consolidated or variable interests that are required to be disclosed under the requirements of the Guideline.

Future accounting pronouncements

a) *International Financial Reporting Standards* (IFRS): In February 2008, the Accounting Standards Board (AcSB) confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011.

The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section - *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to Exposure Draft.

Terasen, along with Fortis, is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Terasen does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required as well as systems changes that may be necessary to gather and process the information.

b) *Rate-regulated operations*: In March 2007, the AcSB issued an Exposure Draft on rate-regulated operations that proposed: (i) the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, of the CICA Handbook providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation be removed; (ii) the explicit guidance for rate-regulated operations provided in Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*, be removed; and (iii) Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation*, be retained as is. The AcSB has also observed that relying on US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71), as another source of Canadian GAAP in the absence of CICA Handbook guidance addressing the specific circumstances of entities subject to rate regulation, is consistent with Section 1100 when the qualifying criteria of FAS 71 are met.

In August 2007, the AcSB issued a Decision Summary on the Exposure Draft that supported the removal of the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, and the amendment to Section 3465, *Income Taxes*, to recognize future income tax liabilities and assets as well as an offsetting regulatory assets or liabilities for entities subject to rate regulation. Both changes will apply prospectively for fiscal years beginning on or after January 1, 2009. It was also decided that the current guidance pertaining to property, plant and equipment and disposal of long-lived assets and discontinued operations, consolidated financial statements be maintained and that the existing AcG-19 will not be withdrawn from the Handbook but that the guidance will be updated as a result of the other changes. The AcSB also decided that the final Background Information and Basis for Conclusions associated with its rate regulation project would not express any views of the AcSB regarding the status of US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, as an "other source of GAAP" within the Canadian GAAP hierarchy.

Effective January 1, 2009, the impact on the Company of the amendment to Section 3465, *Income Taxes*, will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to or recovered from customers in future gas rates. Currently, the Company uses the taxes payable method of accounting for income taxes on regulated earnings. The estimated effect on the Company's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2008, would have been an increase in future tax liabilities of $321.3 million, including those associated with income taxes that will become payable on future revenues as they are collected from customers when the tax timing differences reverse. There would also be a corresponding increase in regulatory assets. Terasen is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate regulated operations.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Company must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, 3061, 3465, and 3475. All assets and liabilities arising from rate regulation do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. These assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Company's consolidated financial statements if it had adopted the removal of the temporary exemption in Section 1100, for the year ended December 31, 2008. Terasen is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate-regulated operations.

c) Effective January 1, 2009, the Company will be adopting the new CICA Handbook Section 3064, *Goodwill and Intangible Assets,* which converges GAAP for goodwill and intangible assets with IFRS. The new standard provides for more comprehensive guidance on intangible assets, in particular for internally developed intangible assets. The Company is still assessing the financial reporting impact of adopting this standard.

3. Segment disclosures

2008

In millions of dollars	Natural gas transmission and distribution	Other activities	Total
Revenues	**$ 1,905.2**	**$ 16.3**	**$ 1,921.5**
Cost of natural gas	**1,267.8**	**-**	**1,267.8**
Cost of revenues from other activities	**-**	**0.2**	**0.2**
Operation and maintenance	**199.3**	**4.9**	**204.2**
Depreciation and amortization	**97.3**	**6.7**	**104.0**
Property and other taxes	**53.5**	**-**	**53.5**
	1,617.9	**11.8**	**1,629.7**
Operating income	**287.3**	**4.5**	**291.8**
Financing costs	**131.4**	**36.1**	**167.5**
Income taxes (recovery) on earnings	**37.0**	**(14.4)**	**22.6**
Net earnings (loss) and comprehensive earnings (loss)	**118.9**	**(17.2)**	**101.7**
Total assets	**4,537.3**	**221.3**	**4,758.6**
Goodwill	**818.1**	**-**	**818.1**
Capital expenditures	**204.6**	**8.4**	**213.0**

2007

In millions of dollars	Natural gas transmission and distribution	Other activities	Total
Revenues	$ 1,750.8	$ 17.7	$ 1,768.5
Cost of natural gas	1,128.6	-	1,128.6
Cost of revenues from other activities	-	8.0	8.0
Operation and maintenance	192.0	5.8	197.8
Depreciation and amortization	94.1	5.6	99.7
Property and other taxes	53.1	0.2	53.3
	1,467.8	19.6	1,487.4
Operating income (loss)	283.0	(1.9)	281.1
Financing costs	125.7	96.8	222.5
Gain on sale of property, plant and equipment	(8.2)	-	(8.2)
Income taxes (recovery) on earnings	53.8	(23.4)	30.4
Earnings (loss) before discontinued operations	111.7	(75.3)	36.4
Loss from discontinued operations, net of income taxes of $101.3 million (Note 4)	-	(410.2)	(410.2)
Net earnings (loss) and comprehensive earnings (loss)	111.7	(485.5)	(373.8)
Total assets	4,361.2	63.9	4,425.1
Goodwill	824.1	-	824.1
Capital expenditures	168.2	6.4	174.6

The segmented disclosures in these consolidated financial statements report the petroleum transportation operations as discontinued operations. Terasen's 30 per cent share of CWLP is included in other activities.

4. Discontinued operations and dispositions

On April 18, 2007, it was announced Kinder Morgan Energy Partners would acquire the Trans Mountain pipeline system from Terasen. Subsequently, on April 30, 2007 the assets were transferred to Kinder Morgan Energy Partners. This transaction caused the Company to consider the fair value of the Trans Mountain pipeline system, which was previously included in the Petroleum Segment, in determining whether goodwill related to these assets was impaired. Accordingly, based on the Company's consideration of the transaction value and supporting third-party information obtained regarding the fair values of the Trans Mountain pipeline system assets, a goodwill impairment charge of $441.9 million was recorded in the year and has been included in the loss on discontinued operations.

On April 30, 2007, Terasen sold the assets of the Trans Mountain system to Kinder Morgan Energy Partners for proceeds of $549 million US. During the month of May, the remaining petroleum transportation businesses within Terasen were transferred to a company affiliated with Kinder Morgan Energy Partners for fair value. In return for the assets, the Company redeemed $1,311.5 million of preferred shares (Note 11). The Company recorded an after-tax charge to equity in the amount of $531.2 million, net of current income tax expense of $101.3 million and future income tax recoveries of $172.7 million, related to the sale of these businesses. The revenue and expense items for 2007 have been classified as discontinued operations.

5. Investments in jointly-controlled entities

As at December 31, 2008 and 2007, the Company has a 30 per cent interest in CWLP for which it uses the proportionate consolidation method of accounting.

The Company's proportionate share of assets, liabilities, revenues, expenses, and cash flows related to this proportionately consolidated entity are summarized as follows:

In millions of dollars	**2008**	2007
Current assets	**$ 8.7**	$ 7.8
Long-term assets (including property, plant and equipment)	**27.5**	30.0
Current liabilities	**17.8**	20.7
Revenues	**8.9**	16.8
Expenses (including financing costs and income tax)	**7.3**	14.4
Net earnings from continuing operations	**1.6**	2.4
Cash flows from operating activities	**6.9**	(4.2)
Cash flows from investing activities	**(3.7)**	(5.3)
Cash flows from financing activities	**-**	-

6. Property, plant and equipment

2008

	Weighted average depreciation rate	**Cost**	**Accumulated depreciation**	**Net book value**
Natural gas transmission and distribution systems	**2.35%**	**$ 2,781.0**	**$ 208.3**	**$ 2,572.7**
Plant, buildings and equipment	**7.42%**	**254.9**	**51.3**	**203.6**
Land and land rights	**0.12%**	**89.3**	**0.4**	**88.9**
Assets under construction	**-**	**120.0**	**-**	**120.0**
		$ 3,245.2	**$ 260.0**	**$ 2,985.2**

2007

	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book value
Natural gas transmission and distribution systems	2.33%	$ 2,660.8	$ 157.9	$ 2,502.9
Plant, buildings and equipment	8.15%	235.8	21.3	214.5
Land and land rights	0.03%	87.4	0.3	87.1
Assets under construction	-	47.8	-	47.8
		$ 3,031.8	$ 179.5	$ 2,852.3

As allowed by the regulators, during the year ended December 31, 2008, the Company capitalized an allowance for equity funds during construction at approved rates of $2.7 million (2007 - $1.4 million) and approved capitalized overhead of $32.7 million (2007 - $32.6 million), with offsetting inclusions in earnings.

7. Rate stabilization accounts

In millions of dollars	**2008**	2007
Current assets		
RDDA	**$ 3.6**	$ 14.2
RSAM	**-**	5.9
CCRA	**53.9**	34.8
MCRA	**-**	20.4
GCVA	**19.0**	3.0
	76.5	78.3
Long-term assets		
RDDA	**-**	6.9
RSAM	**-**	11.8
	-	18.7
Current liabilities		
MCRA	**(23.7)**	-
Long-term liabilities		
RSAM	**(7.7)**	-
Net rate stabilization accounts	**$ 45.1**	$ 97.0

The current portion of the rate stabilization accounts represents the amounts expected to be recovered or refunded in rates over the next year. Actual recoveries (refunds) will vary depending on actual natural gas consumption and recovery amounts approved by the BCUC. Rate stabilization accounts are presented net of tax, where applicable.

The RSAM account is anticipated to be refunded in rates over three years. Refund of the RSAM balance is dependent upon annually approved rates and actual gas consumption volumes. The MCRA and CCRA accounts are anticipated to be fully recovered or paid within the next fiscal year. The RDDA has accumulated the allowed earnings in excess of achieved earnings prior to 2003 and is to be recovered through future rates. During the years ended December 31, 2008 and 2007, the RDDA has decreased as achieved earnings have exceeded the allowed return.

In the absence of rate regulation, the costs in the rate stabilization accounts above would have been expensed as incurred which would have resulted in increased natural gas transmission and distribution revenues of $631.4 million (2007 - $568.6 million), increased cost of natural gas of $556.5 million (2007 - $554.7 million) increased income tax expense of $22.9 million (2007 - $3.5 million), decreased other comprehensive income of $17.6 million (2007 - increased $65.5 million) related to the gas derivatives, and increased net earnings of $17.4 million (2007 - $9.9 million) related to the RDDA.

8. Other assets

In millions of dollars	2008	2007
Deferred charges		
Subject to rate regulation and approval for recovery in rates:		
Income taxes recoverable on post-employment benefits	**$ 17.7**	$ 15.5
Residential unbundling costs	**6.5**	8.6
Corporate capital tax deferrals	**0.7**	2.4
Replacement transportation agreement	**0.7**	1.3
Commercial commodity unbundling costs	**-**	1.2
Other items included approved for recovery in rates	**6.1**	5.1
Subject to rate regulation but not yet approved for recovery in rates:		
Southern Crossing Pipeline PST reassessment	**7.3**	7.2
Deferred development costs for capital projects	**4.6**	4.2
Included in non-regulated entities:		
Other items included in non-regulated entities	**3.0**	2.5
	46.6	48.0
Pension assets (Note 12)	**20.1**	14.0
Investments	**-**	0.3
Long-term receivables	**9.1**	9.2
	$ 75.8	$ 71.5

Amortization of these deferred charges in rates for the year ended December 31, 2008 totalled $4.0 million (2007 - $3.5 million).

The deferral account for income taxes on post-employment benefits relates to income tax amounts on post-employment benefit expense. The BCUC allows post-employment benefits to be collected from customers through rates calculated on the accrual basis, rather than a cash paid basis, which produces timing differences for income tax purposes. Since Terasen Gas accounts for income taxes using the taxes payable basis of accounting, the tax effect of this timing difference is included in other assets, and will be reduced as cash payments for post-employment benefits exceed required accruals and amounts collected from customers in rates.

The residential and commercial commodity unbundling costs deferred are costs incurred to develop a third-party marketer alternative for residential and commercial customers to purchase natural gas from suppliers other than the Company. The BCUC has approved the recovery of these costs in rates over a three-year period.

The deferral for corporate capital tax relates to tax payments that were made to the Province related to assessments for corporate capital tax for TGVI. In November 2006, the Supreme Court of BC decided in favour of the Company in respect of some of the significant issues under appeal. Amounts will be recovered from customers in future rates.

The deferral account for the replacement transportation agreement relates to amounts that Terasen Gas is allowed to recover from customers in rates in order to cover any shortfall in revenues relative to a minimum amount approved by the BCUC on the Company's Southern Crossing Pipeline (SCP). The deferral account is being amortized and recovered in rates over a five-year period, of which one year remains at December 31, 2008.

The deferral account for the SCP PST reassessment relates to a payment made in regards to a reassessment of additional provincial sales tax on the SCP. See Note 17. In 2006, the Company made a payment of $10 million pending resolution of the appeal as a good faith payment in order to forestall an order from the Province of British Columbia (the Province) to provide full payment or security. During 2007, the assessment was reduced to $7.0 million and the overpayment was refunded to the Company. Incremental costs associated with the appeal are being deferred. Depending on the success of the appeal, the Company will either be refunded this payment from the Province or alternatively expects to recover the costs from customers in future rates.

Deferred development costs for capital projects include costs for projects under development that are expected to be added to regulated rate-base in future periods. These costs include approximately $4.6 million (2007 - $4.2 million) for capital projects that are currently in progress by the natural gas transmission and distribution operations.

Deferred charges for rate-regulated entities that have been aggregated in the table above and in the table in "Other long-term liabilities and deferred credits" in Note 10 relate to more than 56 deferral accounts, none of which exceed $1.6 million individually. All of these accounts have been approved by regulators in prior annual rate approvals or orders and are being amortized over various periods depending on the nature of the costs.

In the absence of rate regulation, the deferred charges in the above table would have been recorded in income, except for the costs related to deferred development costs for capital projects, SCP PST Reassessment, the investment balances and the pension assets. This would have resulted in increased natural gas transmission and distribution revenues of $8.4 million (2007 - $2.1 million), decreased cost of natural gas of $1.3 million (2007 - increased $0.6 million), increased operation and maintenance costs $3.1 million (2007 - $11.2 million), decreased depreciation and amortization of $4.0 million (2007 - $3.5 million), increased financing costs of $0.3 million (2007 - $1.0 million), and increased income tax expense of $4.9 million (2007 - decreased $7.3 million).

9. Long-term debt

In millions of dollars		2008	2007
Terasen Inc.			
a)	Medium-Term Note Debentures:		
	6.30% Series 1, due December 1, 2008	$ -	$ 203.8
	5.56% Series 3, due September 15, 2014	129.6	130.3
b)	8.00% Capital Securities, due April 19, 2040	125.0	125.0
		254.6	459.1
Terasen Gas Inc.			
c)	Purchase money mortgages:		
	11.80% Series A, due September 30, 2015	74.9	74.9
	10.30% Series B, due September 30, 2016	200.0	200.0
d)	Debentures and Medium-Term Note Debentures:		
	10.75% Series E, due June 8, 2009	59.9	59.9
	6.20% Series 9, due June 2, 2008	-	188.0
	6.95% Series 11, due September 21, 2029	150.0	150.0
	6.50% Series 18, due May 1, 2034	150.0	150.0
	5.90% Series 19, due February 26, 2035	150.0	150.0
	5.55% Series 21, due September 25, 2036	120.0	120.0
	6.00% Series 22, due October 2, 2037	250.0	250.0
	5.80% Series 23, due May 13, 2038	250.0	-
	Obligations under capital leases, at 4.54% (2007 - 5.61%)	9.7	8.6
		1,414.5	1,351.4
Terasen Gas (Vancouver Island) Inc.			
e)	Senior unsecured debentures: 6.05% Series 2008, due February 15, 2038	250.0	-
f)	Syndicated unsecured credit facility at short-term floating rates, weighted average interest rate of 4.82% in 2007 which matures in 2011. (Note 17)	-	335.0
	Unsecured committed non-revolving credit facility at short-term floating rates, weighted average interest rate of 3.96% (2007 - 5.49%) which matures in 2013 (Note 17)	8.5	4.6
g)	Government repayable loan due 2009 (Note 17)	8.1	6.5
		266.6	346.1
Total long-term debt		1,935.7	2,156.6
Less: current portion of long-term debt		78.5	470.6
Less: long-term debt issue costs		15.6	12.3
		$ 1,841.6	$ 1,673.7

a) Terasen Inc. medium-term note debentures

The Company's Medium-Term Note Debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 21, 2001.

In 2006, the Company entered into a $450 million three-year revolving credit facility. This facility replaced three bi-lateral facilities aggregating $450 million and includes terms and conditions similar to the facilities it replaced. During 2007, this facility was downsized to $100 million. The facility was unutilized at December 31, 2008 and December 31, 2007.

b) Terasen Inc. capital securities

On April 19, 2000, the Company issued $125.0 million of 8.0 per cent Capital Securities with a term to maturity of 40 years for gross proceeds of $123.7 million. The Company may elect to defer payments on these securities and settle such deferred payments in either cash or common shares, and has the option to settle principal at maturity through the issuance of common shares. The securities are exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90 per cent of the market price, subject to the right of the Company to redeem the securities for cash at par as of the same date.

c) Terasen Gas Inc. purchase money mortgages

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on Terasen Gas' Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

d) Terasen Gas Inc. debentures and medium-term note debentures

Terasen Gas' debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

On May 13, 2008, Terasen Gas issued $250.0 million of Medium-Term Note Debentures at a coupon interest rate of 5.80 per cent. The debentures mature on May 13, 2038 and are unsecured and subject to the restrictions of the Trust Indenture. The proceeds were used to repay Terasen Gas' Series 9 Medium-Term Debentures, which matured on June 2, 2008, and the remainder of the proceeds were used to pay down Terasen Gas' operating line.

On October 2, 2007, Terasen Gas issued $250.0 million of Medium-Term Note Debentures at a coupon interest rate of 6.00 per cent. The debentures mature on October 2, 2037 and are unsecured and subject to restrictions of the Trust Indenture. The proceeds were used to repay Terasen Gas' Series 13 and Series 20 Medium-Term Debentures that matured in 2007.

On August 24, 2007, Terasen Gas renegotiated and extended its credit facility for five years with similar terms to the original facility and common for such term credit facilities. The $500 million unsecured committed revolving credit facility is with a syndicate of banks and matures in August 2012. In 2008, under the terms of the agreement, the facility was extended to mature in August 2013.

e) Terasen Gas (Vancouver Island) Inc. bank syndicate

TGVI's debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated February 15, 2008, as amended and supplemented.

On February 15, 2008, TGVI issued $250.0 million of Senior Unsecured Debentures at a coupon interest rate of 6.05 per cent. The debentures mature on February 15, 2038. The proceeds were used to repay the current operating facility.

On January 13, 2006, TGVI entered into a five-year $350 million unsecured committed revolving credit facility with a syndicate of banks. TGVI issued bankers' acceptances under this facility to completely refinance TGVI's former term facility. The bankers' acceptances have terms not to exceed 180 days at the end of which time they are replaced by new bankers' acceptances. The facility can also be utilized to finance working capital requirements and for general corporate purposes. The terms and conditions are similar to those of the previous facility and common for such term credit facilities. Concurrently with executing this facility, TGVI entered into a $20 million seven-year unsecured committed non-revolving credit facility with one bank. This facility can only be utilized for purposes of refinancing any annual prepayments that TGVI may be required to make on non-interest bearing government contributions. The terms and conditions are primarily the same as the aforementioned TGVI facility except this facility ranks junior to repayment of TGVI's Class B subordinated debt, which is held by its parent, the Company. While the bankers' acceptances are short-term, the underlying credit facility on which the bankers' acceptances are committed is open through January 2011. Accordingly, under the $350 million credit facility, borrowings outstanding at December 31, 2007 of $269 million have been classified as long-term debt and an estimated $66.0 million as current maturities. During 2008, the Company paid down this facility with the proceeds from the Senior Unsecured Debentures. Subsequent drawings on this credit facility in 2008 have been included in short-term notes. Borrowings outstanding against the $20 million credit facility at December 31, 2008 were $8.5 million (2007 - $4.6 million) and are included in the current portion of long-term debt.

Long-term debt issue costs are amortized using the effective interest rate method as discussed in Note 2.

The Company's Series 1 and Series 3 Medium-Term Note Debentures and Capital Securities, Terasen Gas' Series B Purchase Money Mortgages, Series E Debentures, and Series 11, Series 18, Series 19, Series 21, Series 22 and Series 23 Medium-Term Note Debentures and TGVI's Series 2008 Senior Unsecured Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

REQUIRED PRINCIPAL REPAYMENTS OVER THE NEXT FIVE YEARS AND THEREAFTER ARE AS FOLLOWS (IN MILLIONS):

2009	$ 78.5
2010	1.9
2011	1.9
2012	1.9
2013	1.9
Thereafter	1,849.6

10. Other long-term liabilities and deferred credits

In millions of dollars	2008	2007
Pension and other post-employment benefit liabilities (Note 12)	$ **77.1**	$ 68.6
Deferred gains on sale of natural gas transmission and distribution assets	**46.3**	50.5
Deferred acquisition payment	**43.3**	40.7
Deferred credits		
Subject to rate regulation and approved for refund in rates:		
Earnings sharing mechanism	**10.7**	12.5
Fair value of foreign exchange forward	**7.4**	-
SCP net mitigation revenue	**6.6**	4.4
SCP west to east transmission revenue	**2.5**	0.9
Deferred interest on MCRA	**1.8**	1.7
Deferred interest mechanism	**1.4**	0.1
Customer benefit from land sale	**0.5**	1.7
Large corporation tax elimination	**-**	2.1
Pension cost variance	**-**	2.3
Other items included approved for repayment in rates	**7.6**	6.5
Other deferred credits/liabilities	**6.8**	8.3
	$ **212.0**	$ 200.3

The deferred gains on sale of natural gas transmission and distribution assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $70.5 million on combined cash proceeds of $141.1 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 17.

The deferred payment resulted from the Company's acquisition of TGVI effective January 1, 2002. The deferred payment has a face value of $52.0 million but was discounted at January 1, 2002 to a present value of $28.2 million. The payment is due on December 31, 2011 or sooner if TGVI realizes revenues from transportation revenue contracts to serve power-generating plants which may be constructed in TGVI's service area. If any part of the deferred payment is paid prior to December 31, 2011, the difference between the payment and the carrying value of the debt will be treated as contingent consideration for the acquisition of TGVI and will be added to the cost of the purchase at that time.

The Earnings Sharing Mechanism is a mechanism agreed to in Terasen Gas' multi-year agreement to share, on a 50/50 basis, amounts earned by Terasen Gas on its regulated activities that exceed or are less than amounts allowed by the BCUC in the cost-of-service allowed return calculations. These amounts are shared on an after-tax basis, and are returned to customers in rates.

The fair value of foreign exchange forward is the fair value of TGVI's foreign exchange forward contract hedging the US dollar payments required under a contract for the construction of the Mt. Hayes Natural Gas Storage Facility. This account captures the change in the fair value of the foreign exchange forward contract and has been approved by the BCUC.

The SCP net mitigation revenue is revenue that is received from third parties for the use of the SCP transportation capacity that has not been utilized by the firm transportation agreement customers. This account is used to record differences between actual revenues from SCP mitigation and what has been approved in the current revenue requirement. Amounts are being amortized to income over five years.

The SCP west to east transmission revenue is revenue that is received from third parties for the use of the SCP west to east transmission system. This account is used to record differences between actual revenues received from the SCP west to east transmission system and what has been approved in the current revenue requirement. Amounts are being amortized to income over five years.

The deferred interest on MCRA is the interest calculated on the difference between the actual and forecasted average balance of the MCRA account multiplied by the composite interest rate.

Terasen Gas has a deferred interest mechanism, which has been approved by the BCUC, that requires that variances due to differences in long-term borrowings and long-term and short-term interest rates from those that have been approved in rates be returned to customers in future rates. The impact of this mechanism was to increase financing costs for the year ended December 31, 2008 by $2.4 million (2007 - nil) from what otherwise would be reported. The balance of the deferred interest account is being amortized on a straight-line basis over three years.

The customer benefit from land sale represents the customers' portion of the net of tax gain on the sale of surplus land that will be refunded to customers by the first quarter of 2009.

The large corporation tax elimination costs resulted from the federal government eliminating the tax on large corporations in 2006. The BCUC allows large corporation tax to be recovered from customers through rates. These costs were collected from customers through rates in 2006 and now are owed back to customers in future rates upon the elimination of the large corporation tax.

The pension cost variance account accumulates differences between pension expense that is approved for recovery in rates and actuarial pension expense. Amounts are recovered in rates in the following year.

Other deferred credits/liabilities include amounts resulting from the Company's acquisition of TGVI effective January 1, 2002.

Amortization of deferred credits in entities that are subject to rate regulation in rates for the year ended December 31, 2008 totalled $5.1 million (2007 - $5.4 million).

In the absence of rate regulation, the other long-term liabilities and deferred credits in the above table would have been recorded in income, aside for the pension and other post-employment benefit liabilities, deferred gains on sale of natural gas transmission and distribution assets and the deferred payment. This would have resulted in increased natural gas transmission and distribution revenues of $4.1 million (2007 - $6.2 million), decreased cost of natural gas of $0.7 million (2007 - increased $0.4 million), decreased operation and maintenance costs of $7.3 million (2007 - $2.6 million), decreased property and other taxes of nil (2007 - $1.1 million), increased depreciation and amortization of $5.1 million (2007 - $5.4 million), decreased financing costs of $2.4 million (2007 - $0.4 million) and increased income tax expense of $3.4 million (2007 - $1.9 million).

11. Share capital and contributed surplus

Authorized share capital

The Company is authorized to issue an unlimited number of common shares and an unlimited number of Class A and Class B preference shares, all without par value. The preference shares are redeemable at the option of the holder.

COMMON SHARES

Changes in the issued and outstanding common shares are as follows:

	2008			2007		
	Number	**Amount**		Number	Amount	
Outstanding, beginning of year	**17,037,853**	**$**	**1,475.3**	14,026,872	$	1,402.7
Issued under:						
Settlement of accounts payable and accrued liabilities	-		-	3,010,981		72.6
	17,037,853	**$**	**1,475.3**	17,037,853	$	1,475.3

PREFERRED SHARES

Changes in the issued and outstanding preferred shares are as follows:

	2008			2007		
	Number	**Amount**		Number	Amount	
Outstanding, beginning of year	**1,183,709.8**	**$**	**1,179.8**	-	$	-
Issued:						
Issuance of preferred shares in settlement of subordinated debt (Note 1)	-		-	2,491,282.0		2,491.3
Redemption:						
On the reorganization and sale of the Pipelines business to affiliated companies (Note 4)	-		-	(1,307,572.2)		(1,311.5)
	1,183,709.8	**$**	**1,179.8**	1,183,709.8	$	1,179.8

All of the common and preferred shares outstanding at December 31, 2008 and December 31, 2007 are owned by Fortis Inc.

CONTRIBUTED SURPLUS

Changes in contributed surplus are as follows:

In millions of dollars	**2008**	2007
Outstanding, beginning of period	**$ 91.0**	$ 19.2
Capital contributions made as part of the reorganization and Pipelines sale in 2007 (Note 4)	**-**	71.8
	$ 91.0	$ 91.0

12. Employee benefit plans

The Company is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. The Company also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan:

Defined benefit plans

Retirement benefits under the defined benefit plans are based on employees' years of credited service and remuneration. Company contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were at December 31, 2005 and December 31, 2007 and the date of the next required valuations are December 31, 2008 and December 31, 2010. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 10.1 years (2007 - 10.3 years).

Effective January 1, 2007 all employees became participants in a new defined benefit pension plan in which costs are split evenly between the employees and employer. All current employees were grandfathered in their respective defined contribution and defined benefit plans and those plans were closed to all new members, except for the TGVI plans which were closed to all new non-unionized members. The most recent actuarial valuation of the new defined benefit pension plan for funding purposes was May 17, 2007 and the date of the next required valuation is December 31, 2009.

Defined contribution plan

Company contributions to the plan are based upon employee age and pensionable earnings for employees of the natural gas transmission and distribution operations. Effective January 1, 2007, all new employees of the Company, except for the TGVI unionized members, became members of the new defined benefit plan described above. Company contributions to the plan are based upon employee age and pensionable earnings for employees.

Supplemental plans

Certain employees are eligible to receive supplemental benefits under both the defined benefit and defined contribution plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and are secured by letters of credit.

Other post-employment benefits

The Company provides retired employees with other post-employment benefits that include, depending on circumstances, supplemental health, dental and life insurance coverage. Post-employment benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health care cost escalation. The most recent actuarial valuations were completed as at December 31, 2005 and December 31, 2007 and the dates of the next required valuations are December 31, 2008 and December 31, 2010. The expected weighted average remaining service life of employees covered by these benefit plans is 9.8 years (2007 - 9.8 years).

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 each year. The financial positions of the employee-defined benefit pension plans and other benefit plans are presented in aggregate in the tables below:

In millions of dollars	Pension benefit plans		Other benefit plans	
	2008	2007	**2008**	2007
Plan assets				
Fair value, beginning of year	**$ 261.2**	$ 334.7	**$ -**	$ -
Sale of Petroleum businesses	**-**	(82.5)	**-**	-
Company contributions	**8.9**	7.8	**1.8**	1.4
Contributions by members	**5.1**	4.4	**-**	-
Actual return on plan assets	**(36.6)**	8.5	**-**	-
Benefits paid	**(11.8)**	(11.6)	**(1.7)**	(1.3)
Other	**(0.5)**	(0.1)	**(0.1)**	(0.1)
Fair value, end of year	**226.3**	261.2	**-**	-
Accrued benefit obligation				
Balance, beginning of year	**280.8**	370.0	**79.4**	89.7
Sale of Petroleum businesses	**-**	(98.1)	**-**	(11.1)
Service cost	**7.4**	7.8	**1.5**	1.6
Interest cost	**14.9**	13.7	**4.2**	4.0
Benefit payments	**(11.8)**	(11.6)	**(1.7)**	(1.3)
Contributions by members	**5.1**	4.4	**-**	-
Actuarial gain	**(16.9)**	(5.4)	**(11.9)**	(3.5)
Balance, end of year	**279.5**	280.8	**71.5**	79.4
Plan deficiency	**(53.2)**	(19.6)	**(71.5)**	(79.4)
Unamortized transitional (benefit) obligation	**(7.5)**	(9.2)	**-**	1.6
Unamortized actuarial loss	**58.8**	21.2	**15.2**	29.2
Unamortized past service costs	**3.1**	3.7	**(1.9)**	(2.1)
Accrued benefit asset (liability)	**$ 1.2**	$ (3.9)	**$ (58.2)**	$ (50.7)
Represented by:				
Pension assets	**$ 20.1**	$ 14.0	**$ -**	$ -
Accrued benefit liability	**(18.9)**	(17.9)	**(58.2)**	(50.7)
	$ 1.2	$ (3.9)	**$ (58.2)**	$ (50.7)

The net accrued benefit liability is included in other long-term liabilities and deferred credits (Note 10) and the pension asset is included in other assets (Note 8).

Included in the accrued benefit obligation and fair value of the plan assets at year-end are the following amounts in respect of plans with accrued benefit obligations in excess of fair value of assets:

In millions of dollars	Pension benefit plans		Other benefit plans	
	2008	2007	**2008**	2007
Accrued benefit obligations:				
Unfunded plans	**$ 26.8**	$ 26.9	**$ 71.5**	$ 79.4
Funded plans	**252.7**	253.9	**-**	-
	279.5	280.8	**71.5**	79.4
Fair value of plan assets	**226.3**	261.2	**-**	-
Funded status deficit	**$ (53.2)**	$ (19.6)	**$ (71.5)**	$ (79.4)

The accrued benefit obligations for certain unfunded pension benefit plans are secured by letters of credit.

The net benefit plan expense is as follows:

In millions of dollars	Pension benefit plans		Other benefit plans	
	2008	2007	**2008**	2007
Current service cost	**$ 7.4**	$ 7.8	**$ 1.5**	$ 1.6
Interest cost on projected benefit obligations	**14.9**	13.7	**4.2**	4.0
Actual loss (return) on plan assets	**36.6**	(8.5)	**-**	-
Net actuarial gains	**(16.9)**	(5.4)	**(11.9)**	(3.5)
Other	**0.5**	0.1	**0.1**	0.1
Net benefit plan (income) expense before adjustments	**42.5**	7.7	**(6.1)**	2.2
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return on plan assets	**(55.4)**	(8.7)	**-**	-
Difference between actual and recognized actuarial gains (losses) in year	**17.8**	6.7	**13.9**	6.3
Difference between actual and recognized past service costs in year	**0.6**	0.6	**(0.2)**	(0.3)
Amortization of transitional (benefit) obligation	**(1.8)**	(1.8)	**1.6**	1.6
Sale of Petroleum businesses	**-**	1.4	**-**	0.6
Net benefit plan expense	**$ 3.7**	$ 5.9	**$ 9.2**	$ 10.4

Benefit plan assets

The weighted-average asset allocation by asset category of the Company's funded defined benefit pension plans is as follows:

	Pension benefit plans	
	2008	2007
Equity securities	**49%**	56%
Fixed income securities	**40%**	36%
Other assets	**11%**	8%
Total assets	**100%**	100%

The investment policy for benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Company's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost-effective manner while not compromising the security of the respective plans. The pension plans utilize external investment managers to manage the investment policy. Assets in the plan are held in trust by independent third parties.

The pension plans do not directly hold any shares of the Company.

Significant assumptions

The discount rate assumption used in determining pension and post-retirement benefit obligations and net benefit expense reflects the market yields, as of the measurement date, on high-quality debt instruments. The expected rate of return on plan assets assumption is reviewed annually by management, in conjunction with actuaries. The assumption is based on the expected returns for the various asset classes, weighted by the portfolio allocation.

The weighted average significant actuarial assumptions used to determine the accrued benefit obligation and the benefit plan expense are as follows:

	Pension benefit plans		Other benefit plans	
	2008	2007	**2008**	2007
Accrued benefit obligation				
Discount rate at December 31, based on AA Corporate bonds	**6.25%**	5.25%	**6.25%**	5.25%
Rate of compensation increase	**3.19%**	3.77%	**-**	-
Net benefit plan expense				
Discount rate at January 1, based on AA Corporate bonds	**5.25%**	5.00%	**5.25%**	5.00%
Expected rate of return on plan assets	**7.25%**	7.25%	**-**	-

The assumed health-care cost trend rates for other post-employment benefit plans are as follows:

	2008	2007
Extended health benefits:		
Initial health-care cost trend rate	**8.0%**	8.0%
Annual rate of decline in trend rate	**1.0%**	1.0%
Ultimate health-care cost trend rate	**5.0%**	5.0%
Year that the rate reaches the ultimate trend rate	**2012**	2011
Medical Services Plan Benefits Premium trend rate	**4.0%**	4.0%

A one percentage-point change in assumed health-care cost trend rates would have the following effects:

2008	One percentage point increase	One percentage point decrease
Effect on the total of the service cost and interest cost components of the benefit plan expense	**$ 0.8**	$ (0.7)
Effect on accrued benefit obligation	**$ 9.7**	$ (8.5)

Cash flows

Total cash contributions for employee benefit plans consist of:

	Employee benefit plans	
	2008	2007
Funded plans	**$ 7.2**	$ 6.1
Beneficiaries of unfunded plans	**3.5**	3.1
Total	**$ 10.7**	$ 9.2

The contributions for 2009 are anticipated to be approximately the same as 2008 for both the defined pension benefit plans and other benefit plans (Note 17).

Impact of rate regulation

As required by the regulator, Terasen Gas is required under its approved cost of service model to defer the amounts of pension benefit expense that exceed or are less than the amounts approved by the regulator to be recovered in rates each year. During the year ended December 31, 2008, the Company has deferred pension expense of $0.4 million (2007 - less than amount approved $1.5 million) that exceeded the amount approved by the regulator to be recovered in rates in 2009.

13. Financing costs

In millions of dollars	2008	2007
Interest and expense on long-term debt	**$ 142.5**	$ 186.3
Interest on short-term debt	**27.1**	37.6
Interest capitalized	**(2.1)**	(1.4)
	$ 167.5	$ 222.5

As allowed by the regulator, during the year ended December 31, 2008, the Company capitalized interest for borrowing requirements for construction of assets that have not been included in rate base of $2.1 million (2007 - $1.4 million).

14. Income taxes

Provision for income taxes

In millions of dollars	2008	2007
Current income taxes	**$ 21.6**	$ 28.9
Future income taxes	**1.0**	1.5
Income tax expense from continuing operations	**$ 22.6**	$ 30.4

Variation in effective income tax rate

Consolidated income taxes vary from the amount that would be computed by applying the Canadian Federal and British Columbia combined statutory income tax rate of 31.0 per cent (2007 - 34.12 per cent) to earnings before income taxes as shown in the following table:

In millions of dollars	2008	2007
Earnings from continuing operations before income taxes	**$ 124.3**	$ 66.8
Combined statutory income tax rate	**31.0%**	34.12%
Combined income taxes at statutory rate	**38.5**	$ 22.8
(Decrease) increase in income taxes resulting from:	**(7.5)**	-
Québec settlement (Note 17)		
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	**(8.3)**	(7.0)
Non-deductible expenses and non-taxable income	**2.4**	5.7
Impact of reassessments related to prior years	**(2.2)**	6.4
Impact of tax rate change on Future Income Taxes balance	**0.4**	1.0
Other, net	**(0.7)**	1.5
Actual consolidated income taxes	**22.6**	$ 30.4
Effective income tax rate	**18.18%**	45.51%

Future income taxes

The net future income tax asset of the Company of $12.1 million (2007 - $13.1 million) relates primarily to the tax effect of temporary differences on non-regulated property, plant and equipment balances.

Currently, the Company uses the taxes payable method of accounting for income taxes on regulated earnings. The estimated effect on the Company's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2008, would have been an increase in future tax liabilities of $321.3 million, including those associated with income taxes that will become payable on future revenues as they are collected from customers when the tax timing differences reverse. There would also be a corresponding increase in regulatory assets.

15. Financial instruments

Fair value estimates

	December 31, 2008		December 31, 2007	
In millions of dollars	**Carrying value**	**Estimated fair value**	Carrying value	Estimated fair value
Held for trading				
Cash and short-term investments[1]	**$ 33.0**	**$ 33.0**	$ 17.8	$ 17.8
Loans and receivables				
Accounts receivable[1, 2]	**392.9**	**392.9**	348.4	348.4
Long-term receivables[1, 2]	**9.1**	**9.1**	9.2	9.2
Other financial liabilities				
Short-term notes[1, 2]	**353.5**	**353.5**	305.0	305.0
Accounts payable and accrued liabilities[1, 2]	**455.0**	**455.0**	385.2	385.2
Due to parent company[1, 2]	**470.3**	**470.3**	135.3	135.3
Long-term debt, including current portion[3, 4, 5]	**1,920.1**	**1,959.2**	2,144.3	2.356.4

1 Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.

2 Carrying value approximates amortized cost.

3 Carrying value is measured at amortized cost using the effective interest rate method.

4 Carrying value at December 31, 2008 is net of unamortized deferred financing costs of $15.6 million (2007 - $12.3 million). On January 1, 2007, deferred financing costs were reclassified from other assets in accordance with the transitional provisions of CICA Section 3855. The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

5 Fair value is calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2008, or by using available quoted market prices.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment. Interest expense associated with the Company's short-term borrowings and long-term debt is disclosed in Note 13 to these consolidated financial statements.

Derivative instruments

The Company hedges its exposure to fluctuations in natural gas prices and foreign exchange rates through the use of derivative instruments. The table below indicates the valuation of the derivative instruments as at December 31, 2008.

In millions of dollars

Asset (liability)	2008				2007	
December 31 (in millions)	**Number of swaps**	**Term to maturity (years)**	**Carrying value**	**Fair value**	Carrying value	Fair value
Foreign exchange forward						
TGVI	**1**	**3**	**$ 7.4**	**$ 7.4**	$ -	$ -
Terasen Gas and TGVI						
Natural gas commodity swaps and options	**228**	**Up to 3**	**$ (84.2)**	**$ (84.2)**	$ (79.4)	$ (79.4)
Gas purchase contract premiums	**74**	**Less than 3**	**(7.6)**	**(7.6)**	5.2	5.2

The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates. The natural gas derivatives fair values have been determined using published market prices for natural gas commodities.

The derivatives entered into by Terasen Gas and TGVI relate to regulated operations and any resulting gains or losses are recorded in rate stabilization accounts, subject to regulatory approval, and passed through to customers in future rates.

Risk management

Exposure to credit risk, liquidity risk, market risk, and natural gas commodity price risk arises in the normal course of the Company's business. The Company enters into financial instruments to finance its operations in the normal course of business.

Credit risk

Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. For cash and short-term investments, derivative assets, accounts receivable, and other receivables due from customers, the Company's credit risk is limited to the carrying value on the balance sheet. The Company generally has a large and diversified customer base, which minimizes the concentration of credit risk.

The Company is exposed to credit risk in the event of non performance by counterparties to derivative financial instruments, including natural gas commodity swaps and options. The Company is also exposed to credit risk on physical off-system sales. Because the Company deals with high credit quality institutions, in accordance with established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations. Counterparty credit exposures are monitored by individual counterparty and by category of credit rating, and are subject to approved limits. The counterparties with which the Company has significant transactions are A-rated entities or better. The Company uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist.

In the case of commercial and industrial customers, credit risk is managed by checking a company's creditworthiness and financial strength both before commencing and during the business relationship. For residential customers, creditworthiness is normally ascertained before commencing commodity delivery by an appropriate mix of internal and external information to determine the payment mechanism required to reduce credit risk to an acceptable level. Certain customers will only be accepted on a prepayment basis. The Company manages its exposure to credit risk associated with all customers by monitoring an aging of receivables and by monitoring groupings of customers according to method of payment or profile.

Receivables from customers are generally considered to be fully performing until such time as the payment that is due remains outstanding past the contractual due date. The contractual due date is generally 22 days. The aging analysis of the Company's consolidated accounts receivable is as follows:

In millions of dollars	December 31, 2008
Not past due	$ 379.8
Past due 0-30 days	13.9
Past due 31-60 days	2.3
Past due 61-90 days	1.0
Past due over 91 days	3.7
Subtotal accounts receivable	400.7
Less: allowance for doubtful accounts	(7.8)
	$ 392.9

Liquidity risk

Liquidity risk is the risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments. The Company's financial position could be adversely affected if it or its operating subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Company and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate this risk, the Company and its subsidiaries had consolidated authorized lines of credit of $950.0 million (2007 - $950.0 million) as at December 31, 2008, of which $552.9 million (2007 - $602.0 million) was unused. The Company targets to have, on average, sufficient liquidity to allow it not to access the capital markets for a period of twelve months.

The following summary outlines the Company's credit facilities by entity.

In millions of dollars					
Credit facilities	Terasen Inc.	Terasen Gas Inc.	Terasen Gas (Vancouver Island) Inc.	**Total as at December 31, 2008**	Total as at December 31, 2007
Total credit facilities	$ 100.0	$ 500.0	$ 350.0	**$ 950.0**	$ 950.0
Credit facilities utilized					
Short-term borrowings	-	(238.5)	(115.0)	**(353.5)**	(305.0)
Letters of credit outstanding	(0.1)	(43.5)	-	**(43.6)**	(43.0)
Credit facilities available	$ 99.9	$ 218.0	$ 235.0	**$ 552.9**	$ 602.0

Furthermore, the Company and its subsidiaries target a strong investment-grade credit rating to maintain capital market access at reasonable interest rates. As at December 31, 2008, the Company's credit ratings were as follows:

Credit ratings	DBRS	Moody's
Terasen Inc.		
Unsecured long-term debt	BBB (High)	Baa2
Capital securities	BBBy	Baa3
Terasen Gas Inc.		
Commercial paper	R-1 (Low)	-
Secured long-term debt	A	A2
Unsecured long-term debt	A	A3
Terasen Gas (Vancouver Island) Inc.		
Unsecured long-term debt	BBB (High)	A3

During the year, Terasen discontinued its commercial paper rating with DBRS.

A downward change in the credit ratings of the Company and its currently rated subsidiaries by one level on January 1, 2008 would have decreased earnings for the year ended December 31, 2008 by $0.7 million.

The following is an analysis of the contractual maturities of the Company's financial liabilities as at December 31, 2008.

In millions of dollars					
Financial liabilities	**≤ 1 year**	**> 1-3 years**	**4-5 years**	**> 5 years**	**Total**
Short-term notes	$ 353.5	$ -	$ -	$ -	$ 353.5
Accounts payable and accrued liabilities	455.0	-	-	-	455.0
Due to parent company	470.3	-	-	-	470.3
Long-term debt, including current portion	78.5	3.8	3.8	1,849.6	1,935.7
	$ 1,357.3	$ 3.8	$ 3.8	$ 1,849.6	$ 3,214.5
Derivative financial assets (liabilities)					
Commodity contracts	$ (69.4)	$ (22.4)	$ -	$ -	$ (91.8)
Foreign exchange forward	4.9	2.5	-	-	7.4

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in foreign exchange rates or market interest rates.

The Company's earnings are not exposed to changes in the US dollar-to-Canadian dollar exchange rate.

TGVI's US dollar payments under a contract for the construction of a LNG storage facility are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. TGVI has entered into a foreign exchange forward contract to hedge this exposure. As at December 31, 2008, a 5 per cent appreciation of the US dollar-to-Canadian dollar exchange rate, as it impacts the measurement of the fair value of the foreign exchange forward contract, in the absence of rate regulation and with all other variables constant, would have increased earnings by $2.9 million for the year ended December 31, 2008. TGVI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than earnings.

Terasen Gas' and TGVI's natural gas derivatives are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The following sensitivity analysis estimates the impact on the fair value of natural gas commodity swaps and options of a 5 per cent appreciation and depreciation of the US dollar-to-Canadian dollar exchange rate, with all other variables remaining constant, for the year ended December 31, 2008. A 5 per cent appreciation of the US dollar-to-Canadian dollar exchange rate would change the fair value of natural gas commodity swaps and options by moving the fair value further out of the money by $0.8 million. This would result in an increase in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts." A 5 per cent depreciation of the US dollar-to-Canadian dollar exchange rate would change the fair value of natural gas commodity swaps and options by reducing the Company's out of the money position by $0.8 million. This would result in a decrease in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts."

The Company and its operating subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating rate debt. The Company and its operating subsidiaries may enter into interest rate swaps to help reduce this risk. Approximately 100 per cent of the

Company's operating facilities are subject to interest rate risk while none of its long-term debt is subject to interest rate risk. In aggregate, the Company attempts to maintain an exposure of not more than 20 per cent of its debt portfolio in floating rate debt. A 50 basis point increase in interest rates would decrease earnings for the year ended December 31, 2008 by $1.8 million. The Company's regulated operations have existing regulatory deferrals that would absorb the impact of interest rate changes.

Commodity price risk

Terasen Gas and TGVI are exposed to risks associated with changes in the market price of natural gas as a result of the natural gas derivatives. Terasen Gas and TGVI's price risk management strategy covers a term of 36 months and aims to (i) improve the likelihood that natural gas prices remain competitive with electricity rates, (ii) dampen price volatility on customer rates and (iii) reduce the risk of regional price disconnects. Any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in deferral accounts, and subject to regulatory approval, are passed through in future rates to customers. The accompanying Balance Sheet at December 31, 2008 includes a net deferral of $91.8 million included in the caption "Current Assets: Current portion of rate stabilization accounts" representing net unrealized losses on these hedges that are recoverable from customers through rates.

The Company's exposure to market risk includes forward-looking statements and represents an estimate of possible changes in fair value that would occur assuming hypothetical future movements in commodity prices. The Company's views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

The following sensitivity analysis estimates the impact on the fair value of natural gas commodity swaps and options of a one dollar change in the value of the underlying price of natural gas, with all other variables remaining constant, for the year ended December 31, 2008. This analysis is for illustrative purposes only, as in practice market rates rarely change in isolation. If the price of natural gas decreased by one dollar per GJ, the change in the fair value of natural gas commodity swaps and options would be to move further out of the money by $51.5 million. This would result in an increase in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts." If the price of natural gas increased by one dollar per GJ, the change in the fair value of natural gas commodity swaps and options would be to reduce the Company's out of the money position by $53.9 million. This would result in a decrease in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts."

Capital management

The Company's principal business of regulated gas distribution utilities requires ongoing access to capital in order to allow it to fund the maintenance and expansion of infrastructure. Wherever possible, the Company raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. In order to ensure access to capital is maintained, the Company targets a long-term consolidated capital structure of 35 per cent equity, including preference shares, 65 per cent debt and investment-grade credit ratings. As well, the Company and its subsidiaries have secured multi-year committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. Committed credit facilities at Terasen are available for general corporate purposes.

Each of the Company's regulated utilities maintains its own capital structure in line with the deemed capital structure approved by the BCUC and ranges between 35 and 40 per cent equity. The long-term capital structure is targeted to be no more than 35 per cent equity as the debt incurred is primarily in support of financing any premiums paid on acquisitions.

The consolidated capital structure of the Company is presented in the following table.

In millions of dollars	December 31, 2008			December 31, 2007		
			%			%
Total debt and capital lease obligations (net of cash and short-term investments)[1]	$	2,240.6	64.5	$	2,431.5	66.8
Shareholder's equity [2]	$	1,232.3	35.5	$	1,207.6	33.2
Total	$	3,472.9	100	$	3,639.1	100

1 Includes long-term debt, including current portion, and short-term borrowings, net of cash and short-term investments.

2 Includes preference shares classified as equity.

Certain of the Company's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 75 per cent of the Company's capital structure, as defined by the long-term debt agreements. Similar restrictions on the issuance of additional debt also exist at the subsidiary level and are generally based on an interest coverage being at least two times available net earnings. In addition, certain of the Company's credit agreements require maintenance of certain financial covenants such as a maximum percentage of debt to equity or minimum interest coverage. As at December 31, 2008 and 2007, the Company and its subsidiaries were in compliance with these covenants.

The Company's credit ratings and credit facilities are disclosed under "Liquidity risk" in Note 15.

16. Related party transactions

The Company's current parent company Fortis Inc. provided corporate management services totalling approximately $4.3 million (2007 - $5.0 million provided by Fortis Inc. and former parent company, Kinder Morgan Inc.) for the year ended December 31, 2008.

The Company was charged interest of approximately $11.6 million (2007 - $3.7 million) during the year ended December 31, 2008 by Fortis Inc. on the borrowings from the parent company including borrowings for the purchase of FortisWest Inc. (FortisWest) shares. The amount due to the parent company is unsecured and due on demand and accrues interest at a bankers acceptance rate plus twenty five basis points.

On May 1, 2008, the Company borrowed $150.0 million from its parent company, Fortis Inc. The proceeds were used to purchase 6,000,000 Series C Preferred Shares (the Shares) of FortisWest, a subsidiary of Fortis Inc. The Shares entitle the Company to a fixed preferential cumulative cash dividend at a rate 6.75 per cent annually with dividends paid quarterly. The interest is also paid quarterly and the advance is due on demand and secured by a pledge of the Shares. For the period from May 1, 2008 to December 31, 2008, the Company paid interest of $6.5 million to Fortis Inc. on the demand loan and the Company received dividends from FortisWest of $6.7 million on the Shares.

The Company's parent, Fortis Inc., grants stock options to certain employees of the Company under its stock option plans. For the year ended December 31, 2008, the Company was charged and recorded an expense of $0.3 million (2007 - $0.1 million) for the fair value of the stock compensation granted by Fortis Inc.

Related party transactions are recorded at the exchange amount.

17. Commitments and contingencies

The Company's subsidiaries and proportionately consolidated entities have entered into operating leases for certain building space and natural gas transmission and distribution assets. In addition, Terasen Gas and TGVI have entered into gas purchase contracts that represent future purchase obligations.

The following table sets forth the Company's operating leases, gas purchase obligations and employee benefit plan contributions due in the years indicated:

In millions of dollars	Operating leases	Purchase obligations	Employee benefit plans	Total
2009	$ 17.4	$ 416.5	$ 10.8	$ 444.7
2010	16.1	26.9	8.5	51.5
2011	15.8	22.8	-	38.6
2012	15.3	-	-	15.3
2013	13.5	-	-	13.5
Thereafter	85.5	-	-	85.5
	$ 163.6	$ 466.2	$ 19.3	$ 649.1

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at December 31, 2008. The employee benefit plan contributions have been estimated up to the date of the next actuarial valuation for each plan unless the valuation falls in the next twelve months then the Company has provided for an estimate of the contributions. Employee benefit plan contributions beyond the date of the next actuarial valuation cannot be accurately estimated.

In prior years, TGVI received non-interest bearing, repayable loans from the Federal and Provincial governments of $50 million and $25 million respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for property, plant and equipment. The government loans are repayable in any fiscal year after 2002 and prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. In 2006, all of the repayment criteria were met when TGVI obtained additional financing through a new credit agreement (Note 9(e)). In addition, since the conditions continue to be met (an annual test) TGVI is expected to make a repayment on the loans in 2009 of approximately $8.1 million (2008 - $6.5 million). As the loans are repaid and replaced with non-governmental loans, property, plant and equipment and long-term debt will increase in accordance with the approved capital structure, as will the rate base used in determining rates. The amounts are not included in the obligations in the table above as the amounts and timing of repayments is dependent upon the approved RDDA recovery each year and the ability to replace the loans with non-government subordinated debt financing on reasonable commercial terms.

Terasen Gas is disputing a $7.0 million assessment of BC Social Service Tax representing additional provincial sales tax and interest on the Southern Crossing Pipeline, which was completed in 2000. The amount was paid in full in 2006 to avoid the accrual of further interest and has been included in other assets. The matter is currently under appeal to the Supreme Court of British Columbia.

During 2007 and 2008 a non-regulated subsidiary of the Company received Notices of Assessment from Canada Revenue Agency for additional taxes related to its 1999 through 2003 taxation years. The Company has fully provided for the exposure in the financial statements. The Company has begun the appeal process on these assessments.

During the year the Company reached a settlement with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of retroactive amending Québec tax legislation. In August 2008, the Company made payments of approximately $16.7 million to settle the tax liability. As a result of the tax settlement, an earnings benefit of $7.5 million was recorded during 2008.

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGVI seeking damages for alleged past overpayments and a future reduction in their tolls. The Statement of Claim does not quantify damages and as such the Company cannot determine the amount of the claim at this time. It is the Company’s view that the claim is without merit.

A number of claims and lawsuits seeking damages and other relief are pending against the Company. Management is of the opinion, based upon information presently available, that it is unlikely that any liability, to the extent not provided for through insurance or otherwise, would be material in relation to the Company’s consolidated financial statements.

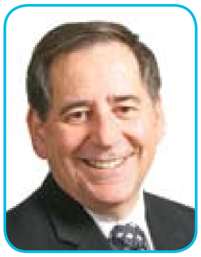
18. Guarantees

The Company has letters of credit outstanding at December 31, 2008 totalling $44.1 million (2007 - $98.8 million) to support its operations and capital projects, including $43.3 million (2007 - $42.9 million) for its unfunded supplemental pension benefit plans. As part of the sale of the Pipelines businesses and ultimate sale of Terasen to Fortis Inc, the Company received a letter of credit from Knight Inc. for those letters of credit that related to the Pipelines businesses. The letter of credit from Knight Inc. totals $0.5 million (2007 - $54.8 million) and would bring the total letters of credit outstanding at December 31, 2008 to $43.6 million (2007 - $44.0 million).

Board of Directors

The Board is responsible for the governance of Terasen Inc. and the Terasen Gas group of companies. Board members' diverse backgrounds and experience reflect the Fortis belief of community involvement in its companies.

With the Board's oversight, Terasen will successfully continue in its role as an energy solutions provider for British Columbians, supporting the Province's economic, energy and environmental goals into 2009 and beyond.



Harold G. Calla

Mr. Calla is Chair of the First Nations Financial Management Board. He is a member of the Squamish Nation and has served two terms on its Council. Since 1986 he has worked with the Squamish Nation representing its interests in commercial business, economic development and accommodation negotiations. Mr. Calla is on the Board of Directors of Partnerships BC and Canada Mortgage and Housing Corporation.

Brenda Eaton

Ms. Eaton is the Chair of BC Housing and is on the Board of Directors of Transelec, Powertech and several not-for-profit organizations. She has held a variety of senior positions in B.C. Public Service, most recently as Deputy Minister to the Premier and prior to that as Deputy Minister in Finance and Treasury Board, Energy Mines and Petroleum Resources and Social Services.

Ida J. Goodreau

Ms. Goodreau is President and CEO of Vancouver Coastal Health Authority. She has held executive positions in the health, forestry and natural gas sectors in Canada and internationally. She is on the Board of Directors of the Vancouver Board of Trade and serves as Chair of the Western Canada Health CEO Forum.

R.L. (Randy) Jespersen

Mr. Jespersen is the President and CEO of Terasen Inc. and the Terasen Gas group of companies. He has been with Terasen Gas Inc. since 1996. His extensive career spans more than 30 years in the energy industry including various roles in Calgary and Houston, Texas. He also serves on the Board of FortisBC Inc., and is a member of the Executive Committee of the Board of the Business Council of B.C. He is an immediate and Past Chair of the Board of the Canadian Gas Association and a former Chair of the Western Energy Institute.

H. Stanley Marshall

Mr. Marshall is the President and CEO of Fortis Inc., serving in this role since 1995. He is a member of the Law Society of Newfoundland and Labrador and is a Registered Professional Engineer. Mr. Marshall serves on the boards of several Fortis companies, is a Director of Toromont Industries Ltd. and is Chairman of the Terasen Inc. and Terasen Gas Inc. Boards.

Harry McWatters

Mr. McWatters is the President of Vintage Consulting Group Inc. and a leader in the British Columbia wine industry. He is the founding Chairman of the British Columbia Wine Institute, a Director of the Canadian Vintners Association, and the founding Chairman of the British Columbia Hospitality Foundation. He has served on the Board of Directors of FortisBC Inc. since 2005, served as Chairman since 2006, and has served on the Fortis Inc. Board since 2007.

Linda S. Petch

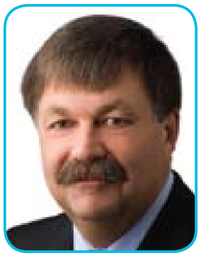
Ms. Petch is the President of Petch & Associates Management Consultants Ltd., a company providing governance and accountability framework services to boards. She is a member of the Board of Governors of RBC Mutual Funds and RBC Private Pools. Ms. Petch is a former director of the Vancouver Island Health Authority and the Health Employers Association of B.C.

Barry V. Perry

Mr. Perry is the Vice President, Finance and Chief Financial Officer of Fortis Inc. He has served in this position since 2004. Prior to his current position at Fortis, he held the position of Vice President, Finance and Chief Financial Officer of Newfoundland Power Inc. Mr. Perry also serves on the boards of several other Fortis companies.

David R. Podmore

Mr. Podmore is the President and CEO of Concert Properties Ltd., a national real estate enterprise he co-founded in 1989. He is the Chair of the B.C. Pavilion Corporation and a Director of LifeLabs Inc. and LifeLabs (B.C.) Inc. He is also Vice Chair of the British Columbia Institute of Technology Foundation, and Past President of the Urban Development Institute of B.C.



John C. Walker

Mr. Walker is the President and CEO of FortisBC Inc. He has worked with the Fortis group of companies since 1983, where he began his career with Newfoundland Power Inc. He is a member of several boards within the Fortis group of companies, including FortisBC Inc., FortisAlberta Inc. and Newfoundland Power Inc.

Leadership Team

Back row left to right: Douglas L. Stout, Dwain A. Bell, Robert M. Samels, Cynthia Des Brisay, Roger A. Dall'Antonia
Front row left to right: Scott A. Thomson, Jan A. Marston, R.L. (Randy) Jespersen, David C. Bennett

Dwain A. Bell *Vice President, Distribution, Terasen Gas*

Mr. Bell became Vice President, Distribution in 2005. He has more than 35 years of experience in the Canadian natural gas distribution business throughout BC and Alberta, including Terasen Gas and Centra Gas British Columbia Inc.

David C. Bennett *Vice President and General Counsel, Terasen Inc. and Terasen Gas group of companies*

Mr. Bennett practiced law in Vancouver until 2000 and then moved to London, England to practice in an international capital markets firm. He returned to BC in 2003 and was in private practice until joining FortisBC in 2004. Mr. Bennett also serves as Vice President, Regulatory Affairs and General Counsel for Fortis BC Inc.

Roger A. Dall'Antonia *Vice President, Corporate Development and Treasurer, Terasen Inc. and Terasen Gas group of companies*

Mr. Dall'Antonia rejoined Terasen in 2007, bringing 15 years of corporate finance and treasury experience. He has considerable experience in senior financial roles in the energy industry including positions with Terasen, Westcoast Energy and Versacold Income Fund.

Cynthia Des Brisay *Vice President, Gas Supply and Transmission, Terasen Gas*

Ms. Des Brisay has been with Terasen Gas since 1999. She has more than 23 years of experience in the energy industry, including oil, gas and independent power generation development in Canada and New Zealand. Her experience with Terasen Gas includes senior positions in major project and business development, most recently as Director, Business Development and Resource Planning.

R.L. (Randy) Jespersen *President and Chief Executive Officer, Terasen Inc. and the Terasen Gas group of companies*

Mr. Jespersen joined Terasen Gas Inc. in 1996. His extensive career spans more than 30 years in the energy industry including various roles in Calgary and Houston, Texas. He serves on the FortisBC Inc. Board, is past chair of the Canadian Gas Association Board and the Western Energy Institute, and is a member of the Executive Committee of the Business Council of British Columbia.

Jan A. Marston *Vice President, Human Resources and Operations Governance, Terasen Gas*

Ms. Marston has been with Terasen Gas since 1996. She has extensive knowledge in the oil and gas production industry and has held a variety of roles with Dome Petroleum, Amoco and Sceptre Resources Ltd. She is President of the Northwest Gas Association and serves on the Board of the Western Energy Institute.

Robert M. Samels *Vice President, Business Services and Chief Information Officer, Terasen Gas*

Mr. Samels joined Terasen Gas in 1991. He spent 12 years as an accountant in private practice prior to becoming Controller and Treasurer of Trans Mountain Pipe Line and holding various senior roles at Terasen Gas including Director of Internal Audit.

Douglas L. Stout *Vice President, Marketing and Business Development, Terasen Gas*

Mr. Stout joined the company in 2001 as Vice President, Gas Supply and Transmission. He has held senior roles with Belkorp Industries Inc. and Husky Energy Inc. and has served as Director for Sultran Ltd., Pacific Coast Terminals and Hillsborough Resources.

Scott A. Thomson *Vice President, Regulatory Affairs and Chief Financial Officer, Terasen Inc. and Terasen Gas group of companies*

Mr. Thomson joined Terasen Gas in 1999. He gained considerable accounting and management consulting experience with Ernst & Young, where he earned his CA in 1988. In 2003, he became Vice President, Finance and Regulatory Affairs for Terasen Gas.

Contact information

Corporate office
Terasen Inc.
Suite 1000, 1111 West Georgia
Vancouver, British Columbia
V6E 4M3

Terasen Inc. terasen.com
Terasen Gas Inc. terasengas.com
Terasen Energy Services Inc. terasenenergyservices.com

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Terasen Inc. is a Canadian corporation headquartered in British Columbia and the parent company of the Terasen Gas companies, the principal natural gas distributor in the province of British Columbia. It is a direct wholly owned subsidiary of Fortis Inc. Terasen Energy Services Inc., an indirect wholly owned subsidiary of Fortis Inc., uses the Terasen Energy Services name and logo under license from Terasen Inc.

Nighttime cover photo
Wakefield Beach, by Dave Delnea
Courtesy of Wakefield Home Builders

2008 Annual Report 03/09 08-208

Terasen

Attachment 45.2

All Adjusted for Splits

	DIVIDENDS							
	CANADIAN UTILITIES -CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.
Dec83	0		0	0	0.000	0	0.24	0.26
Jan84	0		0	0	0.000	0.069	0	0
Feb84	0.13		0.1	0.0575	0.000	0	0	0
Mar84	0		0	0	0.250	0	0.24	0.26
Apr84	0		0	0	0.000	0.069	0	0
May84	0.13		0.1	0.0575	0.000	0	0	0
Jun84	0		0	0	0.000	0	0.24	0.26
Jul84	0		0	0	0.000	0.069	0	0
Aug84	0.13		0.1125	0.0575	0.300	0	0	0
Sep84	0		0	0	0.000	0	0.24	0.26
Oct84	0		0	0	0.000	0.069	0	0
Nov84	0.15		0.1125	0.065	0.000	0	0	0
Dec84	0		0	0	0.000	0	0.28	0.26
Jan85	0		0	0	0.000	0.075	0	0
Feb85	0.15		0.1125	0.065	0.000	0	0	0
Mar85	0		0	0	0.300	0	0.28	0.26
Apr85	0		0	0	0.000	0.075	0	0
May85	0.15		0.1125	0.065	0.000	0	0	0
Jun85	0		0	0	0.000	0	0.28	0.26
Jul85	0		0	0	0.000	0	0	0
Aug85	0.15		0.1125	0.065	0.350	0.075	0	0
Sep85	0		0	0	0.000	0	0.28	0.26
Oct85	0		0	0	0.000	0.085	0	0
Nov85	0.16		0.125	0.07	0.000	0	0	0
Dec85	0		0	0	0.000	0	0.28	0.26
Jan86	0		0	0	0.000	0.085	0	0
Feb86	0.16		0.125	0.07	0.000	0	0	0
Mar86	0		0	0	0.350	0	0.28	0.26
Apr86	0		0	0	0.000	0.085	0	0
May86	0.16		0.125	0.07	0.000	0	0	0
Jun86	0		0	0	0.000	0	0.28	0.26
Jul86	0		0	0	0.000	0.085	0	0
Aug86	0.16		0.125	0.07	0.350	0	0	0
Sep86	0		0	0	0.000	0	0.28	0.26
Oct86	0		0	0	0.000	0.1	0	0
Nov86	0.1625		0.125	0.0775	0.000	0	0	0
Dec86	0		0	0	0.000	0	0.28	0.2
Jan87	0		0	0	0.000	0	0	0
Feb87	0.1625		0.125	0.0775	0.000	0.085	0	0
Mar87	0		0	0	0.175	0	0.28	0.2
Apr87	0		0	0	0.000	0	0	0
May87	0.1625		0.125	0.0775	0.000	0.085	0	0
Jun87	0		0	0	0.175	0	0.28	0.2
Jul87	0		0	0	0.000	0	0	0
Aug87	0.1625		0.125	0.0775	0.000	0.085	0	0
Sep87	0		0	0	0.188	0	0.28	0.2
Oct87	0		0	0	0.000	0	0	0
Nov87	0.165		0.125	0.08	0.000	0.085	0	0
Dec87	0		0	0	0.188	0	0.28	0.2
Jan88	0		0	0	0.000	0	0	0
Feb88	0.165		0.125	0.08	0.000	0.085	0	0
Mar88	0		0	0	0.188	0	0.17	0.2
Apr88	0		0	0	0.000	0	0	0
May88	0.165		0.125	0.08	0.000	0.085	0	0
Jun88	0		0	0	0.188	0	0.17	0.2
Jul88	0		0	0	0.000	0	0	0
Aug88	0.165		0.125	0.08	0.000	0.085	0	0
Sep88	0		0	0	0.188	0	0.17	0.2
Oct88	0		0	0	0.000	0	0	0
Nov88	0.1675		0.125	0.085	0.000	0.085	0	0
Dec88	0		0	0	0.188	0	0.17	0.2
Jan89	0		0	0	0.000	0	0	0
Feb89	0.1675		0.125	0.085	0.000	0.0925	0	0

All Adjusted for Splits

DIVIDENDS

	CANADIAN UTILITIES -CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.
Mar89	0		0	0	0.188	0	0.17	0.2
Apr89	0		0	0	0.000	0	0	0
May89	0.1675		0.125	0.085	0.000	0.0925	0	0
Jun89	0		0	0	0.188	0	0.17	0.2
Jul89	0		0	0	0.000	0	0	0
Aug89	0.168		0.125	0.085	0.188	0.093	0	0
Sep89	0		0	0	0.000	0	0.17	0.2
Oct89	0		0	0	0.000	0	0	0
Nov89	0.17		0.125	0.089	0.000	0.093	0	0
Dec89	0		0	0	0.188	0	0.17	0.2
Jan90	0		0	0	0.000	0	0	0
Feb90	0.17		0.125	0.089	0.000	0.102	0	0
Mar90	0		0	0	0.188	0	0.17	0.2
Apr90	0		0	0	0.000	0	0	0
May90	0.17		0.125	0.089	0.000	0.102	0	0
Jun90	0		0	0	0.188	0	0.144	0.2
Jul90	0		0	0	0.000	0	0	0
Aug90	0.17		0.125	0.089	0.188	0.102	0	0.2
Sep90	0		0	0	0.000	0	0.17	0
Oct90	0		0	0	0.000	0	0	0
Nov90	0.172		0.125	0.093	0.000	0.102	0	0
Dec90	0		0	0	0.188	0	0.18	0.2
Jan91	0		0	0	0.000	0	0	0
Feb91	0.172		0.125	0.093	0.000	0.112	0	0
Mar91	0		0	0	0.188	0	0.18	0.2
Apr91	0		0	0	0.000	0	0	0
May91	0.172		0.125	0.093	0.000	0.112	0	0
Jun91	0		0	0	0.188	0	0.18	0.2
Jul91	0		0	0	0.000	0	0	0
Aug91	0.172		0.125	0.093	0.200	0.112	0	0
Sep91	0		0	0	0.000	0	0.18	0.2
Oct91	0		0	0	0.000	0	0	0
Nov91	0.172		0.125	0.093	0.000	0.112	0	0
Dec91	0		0	0	0.200	0	0.19	0.2
Jan92	0		1.75	0	0.000	0	0	0
Feb92	0.175		0.125	0.093	0.000	0.112	0	0
Mar92	0		0	0	0.200	0	0.19	0.2
Apr92	0		0	0	0.000	0	0	0
May92	0.175		0.125	0.093	0.000	0.112	0	0
Jun92	0		0	0	0.200	0	0.19	0.2
Jul92	0		0	0	0.000	0	0	0
Aug92	0.175		0.125	0.093	0.000	0.112	0	0
Sep92	0		0	0	0.200	0	0.19	0.2
Oct92	0	0.188	0	0	0.000	0	0	0
Nov92	0.175	0	0.125	0.095	0.000	0.112	0	0
Dec92	0	0	0	0	0.200	0	0.21	0.2
Jan93	0	0.188	0	0	0.000	0	0	0
Feb93	0.177	0	0.125	0.095	0.000	0.112	0	0
Mar93	0	0	0	0	0.220	0	0.21	0.2
Apr93	0	0.188	0	0	0.000	0	0	0
May93	0.177	0	0.125	0.095	0.000	0.112	0	0
Jun93	0	0	0	0	0.220	0	0.21	0.2
Jul93	0	0.188	0	0	0.000	0	0	0
Aug93	0.177	0	0.125	0.095	0.000	0.112	0	0
Sep93	0	0	0	0	0.220	0	0.21	0.2
Oct93	0	0.188	0	0	0.000	0	0	0
Nov93	0.177	0	0.125	0.1	0.000	0.112	0	0
Dec93	0	0	0	0	0.220	0	0.23	0.22
Jan94	0	0.19	0	0	0.000	0	0	0
Feb94	0.18	0	0.125	0.1	0.000	0.112	0	0
Mar94	0	0	0	0	0.220	0	0.23	0.22
Apr94	0	0.19	0	0	0.000	0	0	0
May94	0.18	0	0.125	0.1	0.000	0.112	0	0

All Adjusted for Splits

	DIVIDENDS							
	CANADIAN UTILITIES -CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.
Jun94	0	0	0	0	0.220	0	0.23	0.22
Jul94	0	0.19	0	0	0.000	0	0	0
Aug94	0.18	0	0.125	0.1	0.000	0.112	0	0
Sep94	0	0	0	0	0.220	0	0.23	0.22
Oct94	0	0.19	0	0	0.000	0	0	0
Nov94	0.18	0	0.125	0.105	0.000	0.112	0	0
Dec94	0	0	0	0	0.220	0	0.25	0.23
Jan95	0	0.195	0	0	0.000	0	0	0
Feb95	0.183	0	0.125	0.105	0.000	0.112	0	0
Mar95	0	0	0	0	0.220	0	0.25	0.23
Apr95	0	0.195	0	0	0.000	0	0	0
May95	0.183	0	0.125	0.105	0.000	0.112	0	0
Jun95	0	0	0	0	0.240	0	0.25	0.23
Jul95	0	0.195	0	0	0.000	0	0	0
Aug95	0.183	0	0.125	0.105	0.000	0.112	0	0
Sep95	0	0	0	0	0.240	0	0.25	0.23
Oct95	0	0.195	0	0	0.000	0	0	0
Nov95	0.183	0	0.125	0.108	0.000	0.112	0	0
Dec95	0	0	0	0	0.240	0	0.27	0.24
Jan96	0	0.2	0	0	0.000	0	0	0
Feb96	0.185	0	0.125	0.108	0.000	0.112	0	0
Mar96	0	0	0	0	0.240	0	0.27	0.24
Apr96	0	0.2	0	0	0.000	0	0	0
May96	0.185	0	0.125	0.108	0.000	0.112	0	0
Jun96	0	0	0	0	0.240	0	0.27	0.26
Jul96	0	0.2	0	0	0.000	0	0	0
Aug96	0.185	0	0.129	0.108	0.000	0.112	0	0
Sep96	0	0	0	0	0.240	0	0.27	0.26
Oct96	0	0.2	0	0	0.000	0	0	0
Nov96	0.185	0	0.129	0.108	0.000	0.112	0	0
Dec96	0	0	0	0	0.240	0	0.29	0.29
Jan97	0	0.203	0	0	0.000	0	0	0
Feb97	0.195	0	0.129	0.11	0.000	0.112	0	0
Mar97	0	0	0	0	0.240	0	0.29	0.29
Apr97	0	0.203	0	0	0.000	0	0	0
May97	0.195	0	0.129	0.11	0.000	0.125	0	0
Jun97	0	0	0	0	0.240	0	0.29	0.29
Jul97	0	0.203	0	0	0.000	0	0	0
Aug97	0.195	0	0.136	0.11	0.000	0.125	0	0
Sep97	0	0	0	0	0.260	0	0.29	0.31
Oct97	0	0.203	0	0	0.000	0	0	0
Nov97	0.195	0	0.136	0.11	0.000	0.125	0	0
Dec97	0	0	0	0	0.260	0	0.31	0.31
Jan98	0	0.205	0	0	0.000	0	0	0
Feb98	0.205	0	0.136	0.112	0.000	0.125	0	0
Mar98	0	0	0	0	0.260	0	0.31	0.31
Apr98	0	0.205	0	0	0.000	0	0	0
May98	0.205	0	0.144	0.112	0.000	0.14	0	0
Jun98	0	0	0	0	0.280	0	0.31	0.306
Jul98	0	0.205	0	0	0.000	0	0	0
Aug98	0.205	0	0.144	0.112	0.000	0.14	0	0
Sep98	0	0	0	0	0.280	0	0.28	0.326
Oct98	0	0.205	0	0	0.000	0	0	0
Nov98	0.205	0	0.144	0.112	0.000	0.14	0	0
Dec98	0	0	0	0	0.280	0	0.28	0.32
Jan99	0	0.207	0	0	0.000	0	0	0
Feb99	0.215	0	0.144	0.112	0.000	0.14	0	0
Mar99	0	0	0	0	0.280	0	0.28	0.323
Apr99	0	0.207	0	0	0.000	0	0	0
May99	0.215	0	0.151	0.112	0.000	0.147	0	0
Jun99	0	0	0	0	0.280	0	0.28	0.321
Jul99	0	0.207	0	0	0.000	0	0	0
Aug99	0.215	0	0.151	0.112	0.000	0.147	0	0

All Adjusted for Splits

	DIVIDENDS							
	CANADIAN UTILITIES -CL A	**EMERA INC**	**ENBRIDGE INC**	**FORTIS INC**	**PACIFIC NORTHERN GAS LTD**	**TERASEN INC**	**TRANSCANADA CORP**	**WESTCOAST ENERGY INC**
	CU.	**EMA.**	**ENB.**	**FTS.**	**PNG.**	**TER.1**	**TRP.**	**W.**
Sep99	0	0	0	0	0.280	0	0.28	0.325
Oct99	0	0.207	0	0	0.000	0	0	0
Nov99	0.215	0	0.151	0.115	0.000	0.147	0	0
Dec99	0	0	0	0	0.280	0	0.28	0.326
Jan00	0	0.21	0	0	0.000	0	0	0
Feb00	0.225	0	0.151	0.115	0.000	0.147	0	0
Mar00	0	0	0	0	0.280	0	0.2	0.32
Apr00	0	0.21	0	0	0.000	0	0	0
May00	0.225	0	0.161	0.115	0.000	0.155	0	0
Jun00	0	0	0	0	0.280	0	0.2	0.319
Jul00	0	0.21	0	0	0.000	0	0	0
Aug00	0.225	0	0.161	0.115	0.000	0.155	0	0
Sep00	0	0	0	0	0.000	0	0.2	0.315
Oct00	0	0.21	0	0	0.000	0	0	0
Nov00	0.225	0	0.161	0.115	0.000	0.155	0	0
Dec00	0	0	0	0	0.000	0	0.2	0.326
Jan01	0	0.213	0	0.115	0.000	0	0	0
Feb01	0.235	0	0.175	0	0.000	0.155	0	0
Mar01	0	0	0	0	0.000	0	0.225	0.334
Apr01	0	0.213	0	0	0.000	0	0	0
May01	0.235	0	0.175	0.117	0.000	0.165	0	0
Jun01	0	0	0	0	0.000	0	0.225	0.343
Jul01	0	0.213	0	0	0.000	0	0	0
Aug01	0.235	0	0.175	0.117	0.000	0.165	0	0
Sep01	0	0	0	0	0.000	0	0.225	0.336
Oct01	0	0.213	0	0	0.000	0	0	0
Nov01	0.235	0	0.175	0.117	0.000	0.165	0	0
Dec01	0	0	0	0	0.000	0	0.225	0.335
Jan02	0	0.215	0	0	0.000	0	0	0
Feb02	0.245	0	0.19	0.117	0.000	0.165	0	0.342
Mar02	0	0	0	0	0.000	0	0.25	0
Apr02	0	0.215	0	0	0.000	0	0	
May02	0.245	0	0.19	0.123	0.000	0.18	0	
Jun02	0	0	0	0	0.000	0	0.25	
Jul02	0	0.215	0	0	0.000	0	0	
Aug02	0.245	0	0.19	0.123	0.000	0.18	0	
Sep02	0	0	0	0	0.000	0	0.25	
Oct02	0	0.215	0	0	0.000	0	0	
Nov02	0.245	0	0.19	0.123	0.000	0.18	0	
Dec02	0	0	0	0	0.000	0	0.25	
Jan03	0	0.215	0	0	0.000	0	0	
Feb03	0.255	0	0.207	0.13	0.000	0.18	0	
Mar03	0	0	0	0	0.200	0	0.27	
Apr03	0	0.215	0	0	0.000	0	0	
May03	0.255	0	0.207	0.13	0.000	0.195	0	
Jun03	0	0	0	0	0.200	0	0.27	
Jul03	0	0.215	0	0	0.000	0	0	
Aug03	0.255	0	0.207	0.13	0.000	0.195	0	
Sep03	0	0	0	0	0.200	0	0.27	
Oct03	0	0.215	0	0	0.000	0	0	
Nov03	0.255	0	0.207	0.13	0.000	0.195	0	
Dec03	0	0	0	0	0.200	0	0.27	
Jan04	0	0.22	0	0	0.000	0	0	
Feb04	0.265	0	0.229	0.135	0.000	0.195	0	
Mar04	0	0	0	0	0.200	0	0.29	
Apr04	0	0.22	0	0	0.000	0	0	
May04	0.265	0	0.229	0.135	0.000	0.21	0	
Jun04	0	0	0	0	0.200	0	0.29	
Jul04	0	0.22	0	0	0.000	0	0	
Aug04	0.265	0	0.229	0.135	0.000	0.21	0	
Sep04	0	0	0	0	0.200	0	0.29	
Oct04	0	0.22	0	0	0.000	0	0	
Nov04	0.265	0	0.229	0.135	0.000	0.21	0	

All Adjusted for Splits

DIVIDENDS

	CANADIAN UTILITIES -CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.
Dec04	0	0	0	0	0.200	0	0.29	
Jan05	0	0.222	0	0	0.000	0	0	
Feb05	0.275	0	0.25	0.142	0.000	0.225	0	
Mar05	0	0	0	0	0.200	0	0.305	
Apr05	0	0.222	0	0	0.000	0	0	
May05	0.275	0	0.25	0.142	0.000	0.225	0	
Jun05	0	0	0	0	0.200	0	0.305	
Jul05	0	0.222	0	0	0.000	0	0	
Aug05	0.275	0	0.25	0.142	0.000	0.225	0	
Sep05	0	0	0	0	0.200	0	0.305	
Oct05	0	0.222	0	0	0.000	0	0	
Nov05	0.275	0	0.287	0.16	0.000	0.225	0	
Dec05	0	0	0	0	0.200		0.305	
Jan06	0	0.222	0	0	0.000		0	
Feb06	0.285	0	0.287	0.16	0.000		0	
Mar06	0	0	0	0	0.200		0.32	
Apr06	0	0.222	0	0	0.000		0	
May06	0.285	0	0.287	0.16	0.000		0	
Jun06	0	0	0	0	0.200		0.32	
Jul06	0	0.222	0	0	0.000		0	
Aug06	0.54	0	0.287	0.16	0.000		0	
Sep06	0	0	0	0	0.200		0.32	
Oct06	0	0.222	0	0	0.000		0	
Nov06	0.29	0	0.287	0.19	0.000		0	
Dec06	0	0	0	0	0.200		0.32	
Jan07	0	0.222	0	0.19	0.000		0	
Feb07	0.305	0	0.308	0	0.000		0	
Mar07	0	0	0	0	0.200		0.34	
Apr07	0	0.222	0	0	0.000		0	
May07	0.315	0	0.308	0.21	0.000		0	
Jun07	0	0	0	0	0.200		0.34	
Jul07	0	0.228	0	0	0.000		0	
Aug07	0.315	0	0.308	0.21	0.000		0	
Sep07	0	0	0	0	0.200		0.34	
Oct07	0	0.228	0	0	0.000		0	
Nov07	0.315	0	0.308	0.21	0.000		0	
Dec07	0	0	0	0	0.200		0.34	
Jan08	0	0.237	0	0	0.000		0	
Feb08	0.333	0	0.33	0.25	0.000		0	
Mar08	0	0	0	0	0.220		0.36	
Apr08	0	0.237	0	0	0.000		0	
May08	0.333	0	0.33	0.25	0.000		0	
Jun08	0	0	0	0	0.220		0.36	
Jul08	0	0.237	0	0	0.000		0	
Aug08	0.333	0	0.33	0.25	0.000		0	
Sep08	0	0	0	0	0.220		0.36	
Oct08	0	0.252	0	0	0.000		0	
Nov08	0.333	0	0.33	0.25	0.000		0	
Dec08	0	0	0	0	0.220		0.36	
Jan09	0	0.252	0	0	0.000		0	
Feb09	0.352	0	0.37	0.26	0.000		0	
Mar09	0	0	0	0	0.230		0.38	
Apr09	0	0.252	0	0	0.000		0	
May09	0.352	0	0.37	0.26	0.000		0	

All Adjusted for Splits

PRICES

	CANADIAN UTILITIES CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC				Averge	Prices			
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.	CU	EMA	ENB	FTS	PNG	TER	TRP	W
Dec83	7.88		8.34	3.63	7.38	3.91	15.63	15.00								
Jan84	7.50		7.63	3.72	7.75	4.09	15.25	15.25								
Feb84	7.31		7.31	3.53	7.25	3.81	16.88	14.75								
Mar84	7.25		6.88	3.45	7.13	3.66	15.63	14.63								
Apr84	7.44		6.56	3.56	7.00	3.69	15.00	14.00								
May84	7.00		6.59	3.31	6.94	3.59	16.50	14.00								
Jun84	6.75		7.34	3.38	7.50	3.53	17.00	14.38								
Jul84	6.94		7.44	3.24	7.25	3.50	16.25	13.75								
Aug84	7.13		7.97	3.45	7.63	3.59	18.00	13.13								
Sep84	7.13		7.94	3.69	7.81	3.66	18.75	13.13								
Oct84	8.31		7.94	3.84	7.69	3.69	18.00	13.13								
Nov84	8.31		7.97	4.03	8.06	3.63	20.25	14.50								
Dec84	8.50		8.63	3.95	8.25	3.69	21.75	15.25	7.46	0.00	7.52	3.60	7.52	3.68	17.44	$14.16
Jan85	8.56		8.69	4.19	9.25	3.84	22.25	15.38								
Feb85	8.44		8.47	4.36	8.94	4.00	22.00	15.63								
Mar85	8.63		9.28	4.39	8.88	4.00	24.75	14.88								
Apr85	8.75		9.28	4.31	9.00	4.34	25.00	15.63								
May85	9.38		10.13	4.44	9.25	5.03	28.63	17.50								
Jun85	9.13		10.34	4.78	9.69	5.13	26.63	19.00								
Jul85	8.88		10.69	4.69	9.69	4.94	25.63	18.38								
Aug85	9.00		10.38	4.56	9.88	5.50	25.38	17.38								
Sep85	8.25		10.56	4.34	10.13	5.50	25.25	16.00								
Oct85	9.31		11.03	4.06	9.88	5.78	21.88	16.88								
Nov85	9.75		11.19	4.50	9.75	5.81	23.13	17.50								
Dec85	9.63		10.69	4.34	10.00	6.00	21.63	17.88	8.97	0.00	10.06	4.41	9.53	4.99	24.34	$16.83
Jan86	9.31		10.34	4.25	9.75	5.06	19.63	15.88								
Feb86	9.06		9.56	4.38	9.75	5.44	17.50	14.38								
Mar86	9.56		10.38	4.53	9.00	5.81	19.25	13.63								
Apr86	9.75		10.81	4.78	10.13	5.81	17.25	13.75								
May86	9.56		10.97	4.63	9.50	5.94	18.25	14.75								
Jun86	9.44		10.75	4.69	9.94	6.00	16.25	13.75								
Jul86	9.56		9.75	4.75	9.94	6.00	15.75	13.00								
Aug86	9.63		10.19	4.72	9.75	6.19	17.00	13.13								
Sep86	9.50		10.19	4.72	9.88	6.63	16.75	13.13								
Oct86	9.69		9.78	4.75	10.44	6.75	16.50	12.38								
Nov86	9.63		9.81	4.69	10.19	6.75	16.75	13.00								
Dec86	9.50		10.00	4.56	10.31	6.63	16.88	13.00	9.52	0.00	10.21	4.62	9.88	6.08	17.31	$13.65
Jan87	9.75		10.00	5.00	10.81	6.50	18.00	14.63								
Feb87	10.06		11.31	4.91	11.25	6.75	19.00	14.63								
Mar87	10.44		10.50	5.06	11.81	6.94	20.13	16.25								
Apr87	10.06		11.91	5.38	11.50	7.00	18.88	16.63								
May87	10.06		11.84	5.13	11.69	7.25	18.50	17.25								
Jun87	10.06		12.09	5.16	11.13	7.25	17.63	18.25								
Jul87	10.31		12.75	5.00	12.19	7.50	18.75	18.88								
Aug87	9.88		13.03	5.13	12.44	7.00	18.38	17.63								
Sep87	9.75		13.53	4.66	11.13	6.75	17.50	17.00								
Oct87	9.25		12.75	4.56	10.13	5.63	16.00	14.50								
Nov87	9.06		10.41	4.56	10.38	5.69	14.63	15.38								
Dec87	9.75		10.63	4.75	10.19	5.69	15.75	16.88	9.87	0.00	11.73	4.94	11.22	6.66	17.76	$16.49
Jan88	10.13		10.50	4.50	10.50	6.06	13.63	16.75								
Feb88	10.13		11.31	4.97	11.19	5.75	13.25	16.88								
Mar88	10.00		11.38	4.91	10.81	6.25	13.38	17.25								
Apr88	9.94		11.88	4.91	11.00	6.38	14.88	17.75								

All Adjusted for Splits

PRICES

	CANADIAN UTILITIES CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHE RN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC				Averge	Prices			
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.	CU	EMA	ENB	FTS	PNG	TER	TRP	W
May88	9.13		11.94	4.81	11.00	5.88	13.50	17.38								
Jun88	9.63		11.59	4.78	10.94	6.00	14.00	17.13								
Jul88	9.69		12.09	4.69	11.06	6.06	12.88	16.88								
Aug88	9.31		11.84	4.78	11.25	5.75	12.75	16.88								
Sep88	9.44		11.38	4.97	11.38	6.31	13.50	16.25								
Oct88	9.94		10.88	5.00	11.50	6.50	13.63	16.50								
Nov88	9.69		10.38	4.91	11.50	6.31	14.13	15.75								
Dec88	9.69		10.72	5.00	11.38	6.44	15.00	15.88	9.72	0.00	11.32	4.85	11.13	6.14	13.71	$16.77
Jan89	9.69		11.63	5.03	10.69	6.56	14.75	17.63								
Feb89	9.44		11.19	5.00	10.81	6.56	15.00	16.63								
Mar89	9.75		11.31	5.09	10.69	6.63	16.13	16.88								
Apr89	10.00		11.63	5.28	10.38	6.94	16.25	17.38								
May89	10.31		11.63	5.31	11.50	7.25	14.75	18.25								
Jun89	10.75		12.03	5.50	11.38	7.38	14.75	18.88								
Jul89	11.00		12.38	5.56	11.63	7.63	15.13	19.75								
Aug89	10.13		12.13	5.53	11.75	7.25	16.38	19.50								
Sep89	10.06		11.88	5.56	11.69	7.44	16.75	20.25								
Oct89	10.06		11.94	5.50	11.81	7.50	16.75	20.00								
Nov89	10.31		11.00	5.56	12.19	7.50	17.00	21.25								
Dec89	10.94		11.00	5.59	11.75	7.63	17.00	20.38	10.20	0.00	11.64	5.38	11.35	7.19	15.89	$18.90
Jan90	10.13		11.25	5.53	10.81	7.31	17.00	19.88								
Feb90	9.69		11.50	5.31	11.13	6.94	16.50	20.63								
Mar90	9.81		11.81	5.25	12.38	7.25	16.75	21.75								
Apr90	9.19		11.38	5.00	10.63	7.06	15.00	19.75								
May90	9.56		11.88	5.06	11.19	7.38	15.38	21.00								
Jun90	9.56		12.34	5.03	11.25	7.56	16.13	20.25								
Jul90	9.81		12.28	5.00	11.00	7.69	15.63	21.13								
Aug90	9.75		12.06	5.06	11.25	7.56	17.00	21.63								
Sep90	9.56		12.19	5.00	11.00	7.56	15.25	20.88								
Oct90	9.94		11.94	5.13	10.88	7.25	15.88	22.00								
Nov90	9.69		12.00	5.41	11.25	7.25	17.00	21.75								
Dec90	10.19		11.94	5.41	11.25	7.38	17.00	21.50	9.74	0.00	11.88	5.18	11.17	7.35	16.21	$21.01
Jan91	10.38		11.63	5.50	11.00	7.31	16.63	20.00								
Feb91	9.94		12.03	5.72	11.75	7.56	17.25	20.13								
Mar91	9.69		12.22	5.47	11.56	7.31	17.75	20.63								
Apr91	9.75		11.91	5.59	12.63	7.25	17.25	20.75								
May91	9.81		7.56	5.75	13.13	7.63	17.88	19.75								
Jun91	9.56		7.63	5.59	13.00	7.56	17.50	19.50								
Jul91	9.56		7.44	5.66	13.50	7.94	17.00	20.00								
Aug91	9.56		7.50	5.69	13.50	7.88	16.63	19.88								
Sep91	9.75		7.59	5.56	14.00	8.06	16.25	19.50								
Oct91	10.44		7.75	5.78	14.13	7.94	17.00	19.88								
Nov91	10.38		7.69	5.84	13.81	8.13	17.38	20.00								
Dec91	10.38		8.09	5.97	13.63	8.56	17.50	20.63	9.93	0.00	9.09	5.68	12.97	7.76	17.17	$20.05
Jan92	10.44		7.03	5.91	14.25	8.75	17.50	20.00								
Feb92	9.75		6.97	5.53	14.38	8.56	16.88	18.63								
Mar92	9.56		6.38	5.50	14.06	8.69	16.38	17.13								
Apr92	9.94		6.25	5.47	13.75	8.00	16.63	17.75								
May92	9.50		6.13	5.41	13.19	7.94	16.88	16.75								
Jun92	10.25		6.22	5.44	13.38	7.94	17.38	15.25								
Jul92	10.81		6.28	5.50	14.00	8.19	18.13	16.25								
Aug92	10.94	11.00	6.34	5.72	14.81	7.50	18.38	17.13								
Sep92	10.75	10.75	6.19	5.69	15.00	7.69	17.88	16.13								

All Adjusted for Splits

PRICES

	CANADIAN UTILITIES CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC				Averge	Prices			
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.	CU	EMA	ENB	FTS	PNG	TER	TRP	W
Oct92	11.13	11.38	6.13	6.03	15.00	7.63	18.00	17.25								
Nov92	10.38	10.75	5.84	5.63	15.75	7.25	17.63	17.38								
Dec92	10.25	10.75	5.75	6.13	16.50	7.38	17.63	17.25	10.31	10.93	6.29	5.66	14.51	7.96	17.44	$17.24
Jan93	10.38	10.50	6.22	6.22	16.50	7.38	16.88	16.50								
Feb93	10.31	10.75	6.25	6.03	16.50	6.94	17.75	17.25								
Mar93	10.88	11.00	6.53	6.06	16.25	7.38	18.63	18.25								
Apr93	11.25	11.38	6.84	6.06	15.50	7.44	18.88	19.88								
May93	11.38	11.63	7.03	6.19	17.00	7.44	18.63	20.13								
Jun93	11.94	11.75	7.09	6.38	17.56	7.63	20.00	21.25								
Jul93	12.25	12.00	7.53	6.56	17.56	8.06	21.25	21.63								
Aug93	12.31	12.50	7.25	6.69	19.50	8.13	21.00	21.38								
Sep93	12.13	12.50	7.25	6.72	19.50	7.94	20.13	21.88								
Oct93	12.81	13.00	7.50	7.13	21.00	8.31	20.25	21.13								
Nov93	12.75	13.00	7.94	6.91	21.00	8.13	20.00	22.00								
Dec93	12.81	13.00	8.06	7.16	22.00	8.31	20.13	22.00	11.77	11.92	7.13	6.51	18.32	7.76	19.46	$20.27
Jan94	13.38	13.13	8.47	7.34	21.88	8.44	20.25	23.88								
Feb94	12.75	13.00	8.28	7.25	22.00	8.00	19.88	24.38								
Mar94	12.13	12.00	7.81	6.91	21.88	7.81	18.50	23.13								
Apr94	12.19	11.75	7.72	6.50	20.75	7.75	18.63	23.88								
May94	12.00	11.63	7.56	6.44	20.63	7.50	18.00	24.00								
Jun94	11.38	11.13	7.16	6.16	20.13	6.81	16.38	20.38								
Jul94	11.63	11.13	7.34	6.19	18.38	7.06	17.13	22.50								
Aug94	11.81	11.50	7.19	6.56	20.00	7.44	18.50	23.00								
Sep94	11.69	11.38	7.22	6.56	20.00	7.25	17.88	22.13								
Oct94	12.31	11.13	7.25	6.78	19.75	7.25	17.38	22.25								
Nov94	11.75	11.38	6.88	6.56	19.50	6.75	17.50	23.38								
Dec94	12.00	11.13	7.13	6.44	20.25	6.75	17.13	22.25	12.08	11.69	7.50	6.64	20.43	7.40	18.09	$22.93
Jan95	11.75	11.00	6.84	6.19	19.00	6.69	17.50	20.75								
Feb95	11.06	11.25	7.31	6.16	18.75	6.81	18.38	21.25								
Mar95	11.38	11.50	7.56	6.44	18.75	6.94	17.88	20.88								
Apr95	11.63	11.63	7.59	6.31	19.00	7.06	18.00	21.63								
May95	11.75	11.88	7.50	6.44	19.75	7.19	18.13	20.75								
Jun95	12.00	11.50	7.56	6.47	19.75	7.25	18.38	20.38								
Jul95	12.50	11.88	7.38	6.63	19.50	7.19	18.63	20.75								
Aug95	12.19	11.50	7.72	6.88	20.00	7.25	18.50	20.50								
Sep95	12.25	11.63	7.69	6.75	20.50	7.31	17.75	19.88								
Oct95	12.44	11.25	8.06	6.84	20.00	7.38	17.88	20.13								
Nov95	12.69	12.13	8.03	6.81	20.63	7.63	18.25	20.00								
Dec95	13.00	12.38	7.97	6.81	21.00	8.00	18.88	20.13	12.05	11.63	7.60	6.56	19.72	7.22	18.18	$20.58
Jan96	13.19	12.50	8.31	6.84	19.75	8.00	19.75	21.25								
Feb96	13.13	12.13	8.19	6.88	19.50	7.88	19.38	21.75								
Mar96	12.75	12.38	8.25	6.91	18.00	7.94	19.00	20.63								
Apr96	13.20	12.45	8.36	7.05	18.00	8.13	19.05	20.95								
May96	13.13	12.35	8.45	7.08	18.15	8.28	19.80	20.50								
Jun96	13.50	12.50	8.58	7.24	18.10	8.40	20.25	20.35								
Jul96	13.73	12.35	8.83	7.48	19.65	8.98	21.25	21.05								
Aug96	14.30	12.75	9.06	7.60	19.90	9.50	21.85	21.75								
Sep96	14.15	13.00	9.23	7.89	19.70	9.28	21.85	21.90								
Oct96	16.13	14.30	10.13	8.51	20.10	9.90	22.75	22.15								
Nov96	15.95	14.15	10.00	8.21	21.50	10.00	24.20	24.15								
Dec96	15.28	14.35	9.99	8.50	22.25	10.15	24.00	22.95	14.03	12.93	8.95	7.51	19.55	8.87	21.09	$21.61
Jan97	16.13	13.95	9.99	8.43	20.85	10.25	24.55	23.60								
Feb97	15.70	14.15	9.99	8.23	20.80	10.70	25.35	24.85								

All Adjusted for Splits

PRICES

	CANADIAN UTILITIES CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC				Averge	Prices			
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.	CU	EMA	ENB	FTS	PNG	TER	TRP	W
Mar97	15.55	14.05	9.98	7.89	20.30	10.63	25.15	24.35								
Apr97	16.35	14.25	10.44	8.30	20.75	11.50	25.55	24.10								
May97	17.73	14.25	10.93	8.33	21.75	12.10	26.70	25.05								
Jun97	17.95	14.25	11.54	8.66	21.10	13.00	27.75	25.30								
Jul97	19.85	15.05	13.63	8.64	22.50	13.10	27.45	27.75								
Aug97	18.55	14.40	12.40	8.65	23.60	12.40	26.00	26.55								
Sep97	19.28	14.75	13.58	9.23	25.95	12.53	26.75	28.70								
Oct97	19.83	15.20	13.20	9.50	25.50	12.98	26.15	28.90								
Nov97	19.73	16.10	15.75	9.85	26.00	13.00	30.25	32.05								
Dec97	20.33	17.40	16.35	10.50	29.70	13.90	31.90	33.00	18.08	14.82	12.31	8.85	23.23	12.17	26.96	$27.02
Jan98	22.15	18.35	16.40	11.13	28.25	14.48	31.60	35.10								
Feb98	23.40	19.00	16.04	11.31	30.00	15.25	31.95	36.00								
Mar98	23.75	19.90	15.91	11.53	30.00	15.15	33.45	35.00								
Apr98	22.40	19.00	15.75	11.58	29.95	15.60	31.80	33.75								
May98	22.63	19.00	15.84	11.25	31.50	15.78	33.80	34.10								
Jun98	23.08	19.40	16.56	11.25	30.00	15.93	32.60	32.75								
Jul98	21.93	17.60	16.25	10.51	30.00	15.30	23.95	28.50								
Aug98	19.40	15.20	14.50	9.00	24.75	14.13	21.30	27.70								
Sep98	20.95	16.75	16.01	9.13	26.00	14.43	22.25	28.75								
Oct98	22.58	18.20	16.78	9.75	27.90	15.88	23.30	30.25								
Nov98	22.73	17.65	17.25	9.65	27.50	14.43	22.85	30.50								
Dec98	24.00	18.20	17.63	9.56	27.30	15.25	22.45	30.50	22.41	18.19	16.24	10.47	28.60	15.13	27.61	$31.91
Jan99	23.88	18.10	17.19	9.34	27.00	14.28	21.50	30.35								
Feb99	23.93	18.20	17.75	9.25	25.50	14.53	20.70	29.60								
Mar99	23.43	16.75	16.71	9.50	24.00	13.63	19.25	29.60								
Apr99	23.23	17.20	16.96	9.20	22.25	14.70	20.10	28.20								
May99	21.75	17.50	17.35	8.76	22.50	15.00	20.40	29.00								
Jun99	22.38	16.65	16.88	8.55	21.35	15.05	20.75	28.90								
Jul99	21.85	17.45	16.50	8.88	20.85	14.35	20.25	28.60								
Aug99	20.70	16.40	15.95	8.74	19.25	13.88	21.05	29.15								
Sep99	20.00	15.60	15.88	8.51	18.50	13.63	19.25	27.45								
Oct99	19.60	15.95	15.85	8.50	18.40	13.23	17.75	26.30								
Nov99	18.00	15.05	14.83	8.28	17.00	11.25	16.25	24.00								
Dec99	19.50	14.40	14.33	7.85	17.35	12.70	12.50	23.15	21.52	16.60	16.35	8.78	21.16	13.85	19.15	$27.86
Jan00	18.25	13.65	13.75	7.51	16.00	11.30	11.70	21.70								
Feb00	17.88	13.00	13.25	7.30	15.55	12.20	9.90	21.00								
Mar00	16.70	13.30	14.73	7.26	15.00	12.50	10.65	24.25								
Apr00	18.88	13.45	16.00	7.78	15.60	13.43	10.50	25.00								
May00	19.50	14.50	17.15	7.75	13.80	14.75	11.70	25.65								
Jun00	20.95	14.25	15.53	8.14	15.00	14.15	11.30	22.80								
Jul00	20.50	14.50	15.95	8.13	9.00	13.50	11.40	25.45								
Aug00	20.23	15.70	16.90	8.15	8.90	14.30	14.30	28.50								
Sep00	20.50	15.30	17.30	8.63	7.50	14.18	14.15	28.65								
Oct00	21.88	15.75	20.50	8.60	9.05	15.50	14.50	34.00								
Nov00	22.00	16.35	20.25	8.59	7.75	15.50	15.35	32.20								
Dec00	25.50	17.70	21.85	9.00	7.95	16.68	17.20	36.20	20.23	14.79	16.93	8.07	11.76	14.00	12.72	$27.12
Jan01	24.45	16.70	18.25	8.81	7.20	15.50	16.20	31.90								
Feb01	25.50	16.07	20.25	8.96	7.10	15.38	18.73	36.00								
Mar01	25.50	17.00	21.18	9.55	7.56	16.25	19.24	36.60								
Apr01	26.53	17.00	18.95	9.58	6.80	15.78	18.22	32.00								
May01	25.00	16.15	20.00	9.39	10.25	17.10	18.40	35.25								
Jun01	25.93	15.95	20.60	9.24	9.75	15.93	18.75	35.73								
Jul01	25.40	16.45	20.33	9.33	9.00	16.80	19.13	36.50								

All Adjusted for Splits

				PRICES												
	CANADIAN UTILITIES CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC				Averge	Prices			
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.	CU	EMA	ENB	FTS	PNG	TER	TRP	W
Aug01	25.53	16.33	20.39	10.20	9.00	17.20	19.51	36.75								
Sep01	25.14	16.43	21.28	10.42	8.75	18.05	20.34	40.20								
Oct01	25.13	17.61	22.12	10.92	9.19	17.75	20.51	41.78								
Nov01	26.00	17.75	22.15	10.52	10.15	17.50	19.97	41.00								
Dec01	24.88	16.74	21.70	11.74	9.60	16.60	19.87	42.20	25.41	16.68	20.60	9.89	8.70	16.65	19.07	$37.16
Jan02	25.38	16.49	21.77	11.44	11.95	17.60	20.55	41.90								
Feb02	27.28	16.25	22.50	12.03	12.60	17.73	22.20	43.55								
Mar02	28.71	16.46	22.37	12.14	14.00	19.04	21.60	43.17								
Apr02	28.45	16.46	23.00	12.06	14.45	19.60	22.79									
May02	29.13	16.91	23.86	12.06	14.75	19.91	23.15									
Jun02	29.45	17.16	23.58	12.28	13.75	20.05	23.00									
Jul02	27.50	16.28	22.80	11.31	11.75	19.08	22.55									
Aug02	26.78	16.46	23.02	12.15	13.75	19.67	23.15									
Sep02	27.75	17.75	23.14	12.50	14.00	20.98	22.60									
Oct02	27.08	17.20	22.00	12.91	14.50	20.13	22.50									
Nov02	27.48	16.17	21.28	12.55	16.15	18.63	22.51									
Dec02	25.61	16.05	21.31	13.13	17.75	19.08	22.92		27.55	16.64	22.55	12.21	14.12	19.29	22.46	$42.87
Jan03	25.99	16.00	21.25	13.00	15.80	20.00	22.70									
Feb03	24.98	15.29	21.25	13.19	14.75	19.62	22.21									
Mar03	23.60	14.60	21.97	12.46	14.85	18.48	21.55									
Apr03	24.43	15.66	21.83	12.71	14.45	19.25	22.90									
May03	26.63	16.64	23.39	13.89	14.71	20.70	24.30									
Jun03	28.00	17.45	23.97	14.75	16.14	21.78	23.75									
Jul03	28.60	17.59	25.15	15.06	16.65	22.23	25.35									
Aug03	27.76	17.30	25.53	14.85	17.00	22.17	24.99									
Sep03	27.50	16.78	24.08	13.88	16.35	21.75	25.07									
Oct03	28.50	17.38	25.90	14.25	18.55	23.14	26.90									
Nov03	28.75	17.92	26.00	14.94	18.55	23.25	27.91									
Dec03	28.93	17.85	26.85	14.73	19.46	23.98	27.88		26.97	16.71	23.93	13.98	16.44	21.36	24.63	$0.00
Jan04	29.74	18.19	25.50	15.61	20.00	23.06	27.05									
Feb04	29.70	18.79	25.95	15.23	21.00	23.51	27.71									
Mar04	31.25	19.25	26.65	16.12	21.30	24.41	28.28									
Apr04	29.25	19.30	25.08	16.00	21.00	24.00	27.15									
May04	27.13	17.38	25.18	14.91	20.50	24.00	27.39									
Jun04	26.45	16.90	24.36	14.54	18.90	23.62	26.40									
Jul04	26.66	17.57	25.05	14.88	18.76	23.55	26.65									
Aug04	27.57	18.30	26.31	15.00	19.40	24.72	27.49									
Sep04	27.58	17.80	26.38	15.31	18.90	24.61	27.65									
Oct04	29.84	18.17	26.44	16.06	18.81	25.25	27.63									
Nov04	29.99	18.72	28.75	16.80	18.80	27.30	29.38									
Dec04	30.16	19.17	29.85	17.38	20.93	27.71	29.80		28.78	18.30	26.29	15.65	19.86	24.64	27.72	
Jan05	29.91	19.60	31.46	18.53	23.65	29.35	29.80									
Feb05	30.50	19.03	30.60	18.32	23.10	28.40	29.72									
Mar05	30.68	18.50	31.10	17.85	19.49	27.20	29.82									
Apr05	30.85	17.86	31.73	18.02	18.60	27.23	29.65									
May05	32.08	18.50	33.40	18.70	19.00	27.15	30.35									
Jun05	34.99	18.80	34.95	19.43	19.30	29.31	32.24									
Jul05	35.50	18.00	35.30	20.60	19.00	31.40	33.59									
Aug05	38.06	18.56	35.02	21.03	17.50	35.85	33.00									
Sep05	39.51	19.60	37.26	24.11	17.80	35.63	35.50									
Oct05	39.68	19.40	36.01	22.00	17.75	35.15	35.07									
Nov05	42.60	19.85	36.18	24.91	19.44	35.38	36.19									
Dec05	43.98	21.04	36.34	24.27	19.55		36.65		35.69	19.06	34.11	20.65	19.52	28.50	32.63	

All Adjusted for Splits

PRICES

	CANADIAN UTILITIES CL A	EMERA INC	ENBRIDGE INC	FORTIS INC	PACIFIC NORTHERN GAS LTD	TERASEN INC	TRANSCANADA CORP	WESTCOAST ENERGY INC				Averge	Prices			
	CU.	EMA.	ENB.	FTS.	PNG.	TER.1	TRP.	W.	CU	EMA	ENB	FTS	PNG	TER	TRP	W
Jan06	40.84	19.43	36.02	23.72	18.10		35.42									
Feb06	40.45	20.00	35.80	23.33	18.35		34.99									
Mar06	38.46	19.10	33.60	22.43	18.60		33.67									
Apr06	37.65	19.20	33.15	21.79	19.20		33.02									
May06	41.25	18.93	34.55	24.15	19.15		33.50									
Jun06	36.90	18.84	33.97	22.29	18.20		31.85									
Jul06	40.25	19.43	36.19	22.50	18.66		34.75									
Aug06	39.96	20.18	36.39	25.12	18.04		35.94									
Sep06	41.02	20.14	36.07	24.44	18.00		35.15									
Oct06	42.10	21.34	37.76	25.65	18.80		36.34									
Nov06	44.67	22.54	40.20	28.15	18.67		38.64									
Dec06	47.73	22.60	40.27	29.77	18.05		40.61		40.94	20.14	36.16	24.45	18.49	0.00	35.32	
Jan07	43.75	21.31	38.31	26.89	18.29		39.03									
Feb07	43.02	20.39	37.11	26.30	18.03		37.30									
Mar07	42.57	20.67	37.66	28.01	17.90		38.35									
Apr07	45.17	21.51	36.60	28.24	17.90		39.57									
May07	49.79	21.63	37.95	28.20	17.99		39.35									
Jun07	46.30	19.90	35.90	26.00	18.15		36.64									
Jul07	47.75	20.66	37.83	26.33	18.25		38.50									
Aug07	48.65	19.82	35.60	26.55	18.24		36.80									
Sep07	48.65	20.15	36.44	27.05	18.25		36.47									
Oct07	54.36	20.48	40.91	28.24	18.25		40.18									
Nov07	50.50	21.45	37.11	27.05	18.30		39.71									
Dec07	46.40	21.89	40.01	28.99	18.75		40.54		47.24	20.82	37.62	27.32	18.19	0.00	38.54	
Jan08	50.23	21.59	40.09	28.65	18.00		39.57									
Feb08	44.95	20.46	40.55	28.05	18.16		39.54									
Mar08	41.49	21.04	42.33	29.21	17.89		39.55									
Apr08	44.34	21.45	41.42	27.81	18.25		36.90									
May08	46.06	22.59	44.24	27.30	18.30		39.16									
Jun08	44.02	23.07	44.06	27.16	17.83		39.50									
Jul08	46.05	23.34	44.93	27.05	17.00		39.70									
Aug08	43.10	23.56	44.53	26.08	17.00		40.27									
Sep08	37.95	21.17	39.38	24.04	17.15		38.17									
Oct08	42.40	21.47	41.86	26.30	16.15		36.42									
Nov08	41.60	21.20	38.10	26.75	14.35		32.70									
Dec08	40.50	22.20	39.56	24.59	13.54		33.17		43.56	21.93	41.75	26.92	16.97	0.00	37.89	
Jan09	39.76	21.75	40.24	24.36	13.70		32.98									
Feb09	41.30	20.38	38.10	24.01	12.10		30.90									
Mar09	36.75	19.03	36.35	22.14	12.05		29.83									
Apr09	34.50	19.76	36.85	22.15	12.71		29.78									
May09	35.38	19.66	38.70	24.00	14.95		32.38		37.54	20.12	38.05	23.33	13.10	0.00	31.17	

Company Name	Ticker Sym	EPS Basic Exc Extra Items[Y83]	EPS Basic Exc Extra Items[Y84]	EPS Basic Exc Extra Items[Y85]	EPS Basic Exc Extra Items[Y86]	EPS Basic Exc Extra Items[Y87]	EPS Basic Exc Extra Items[Y88]	EPS Basic Exc Extra Items[Y89]	EPS Basic Exc Extra Items[Y90]	EPS Basic Exc Extra Items[Y91]	EPS Basic Exc Extra Items[Y92]	EPS Basic Exc Extra Items[Y93]	EPS Basic Exc Extra Items[Y94]	EPS Basic Exc Extra Items[Y95]	EPS Basic Exc Extra Items[Y96]	EPS Basic Exc Extra Items[Y97]	EPS Basic Exc Extra Items[Y98]	EPS Basic Exc Extra Items[Y99]	EPS Basic Exc Extra Items[Y00]	EPS Basic Exc Extra Items[Y01]	EPS Basic Exc Extra Items[Y02]	EPS Basic Exc Extra Items[Y03]	EPS Basic Exc Extra Items[Y04]	EPS Basic Exc Extra Items[Y05]	EPS Basic Exc Extra Items[Y06]	EPS Basic Exc Extra Items[Y07]	EPS Basic Exc Extra Items[Y08]
CANADIAN UTILITIES -CL A	CU.	0.81	0.935	1.035	1.08	0.89	0.94	0.925	0.865	0.895	1	1.035	1.11	1.185	1.34	1.425	1.5	1.58	1.795	1.87	2.405	2.045	2.44	2.09	2.57	3.08	3.29
EMERA INC	EMA.	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	0.45	1.07	1.1	1.11	1.05	1.07	0.99	1.16	1.2	1.2	0.85	1.2	1.2	1.12	1.14	1.36	1.29
ENBRIDGE INC	ENB.	0.8455	0.8685	0.9265	0.84	0.7725	0.65	0.7325	0.91	2.172	0.475	0.507	0.273	0.575	0.725	0.788	0.827	0.955	1.27	1.315	1.045	2.015	1.93	1.65	1.81	1.97	3.67
FORTIS INC	FTS.	@NA	@NA	@NA	@NA	0.52	0.5625	0.5875	0.615	0.603	0.637	0.64	0.615	0.632	0.59	0.595	0.46	0.56	0.637	0.837	0.973	1.063	1.072	1.35	1.42	1.4	1.56
PACIFIC NORTHERN GAS LTD	PNG.	1.155	1.18	1.22	1.09	1.305	1.34	1.445	1.605	1.66	1.55	1.63	1.8	1.67	2.01	2.16	1.73	1.92	1.83	1.52	1.2	1.49	1.41	1.75	1.27	1.11	1.53
TERASEN INC	TER.1	0.44	0.5725	0.7225	0.655	0.64	1.01	0.93	0.895	0.97	0.26	0.715	0.485	0.58	1.265	0.635	0.925	1.06	1.42	1.105	1.225	1.28	1.43	@NA	@NA	@NA	@NA
TRANSCANADA CORP	TRP.	2.13	2.41	2.4	1.2	0.96	0.73	1.18	1.23	1.34	1.56	1.62	1.6	1.75	1.85	1.85	0.77	0.97	1.08	1.41	1.56	1.66	2.02	2.49	2.15	2.31	2.53
WESTCOAST ENERGY INC	W.	1.52	1.41	1.41	1.02	1.26	1.12	1.26	1.43	1.36	1.37	1.82	1.83	2.01	1.96	2.06	1.53	1.95	2.92	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA

		EPS Basic from Operations[Y83]	EPS Basic from Operations[Y84]	EPS Basic from Operations[Y85]	EPS Basic from Operations[Y86]	EPS Basic from Operations[Y87]	EPS Basic from Operations[Y88]	EPS Basic from Operations[Y89]	EPS Basic from Operations[Y90]	EPS Basic from Operations[Y91]	EPS Basic from Operations[Y92]	EPS Basic from Operations[Y93]	EPS Basic from Operations[Y94]	EPS Basic from Operations[Y95]	EPS Basic from Operations[Y96]	EPS Basic from Operations[Y97]	EPS Basic from Operations[Y98]	EPS Basic from Operations[Y99]	EPS Basic from Operations[Y00]	EPS Basic from Operations[Y01]	EPS Basic from Operations[Y02]	EPS Basic from Operations[Y03]	EPS Basic from Operations[Y04]	EPS Basic from Operations[Y05]	EPS Basic from Operations[Y06]	EPS Basic from Operations[Y07]	EPS Basic from Operations[Y08]
CANADIAN UTILITIES -CL A	CU.	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	1.035	1.11	1.185	1.34	1.425	1.5	1.58	1.795	1.87	1.875	2.045	2.155	1.72	2.47	2.79	3.29
EMERA INC	EMA.	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	1.21	1.1	1.11	1.05	1.07	1	1.16	1.21	1.2	0.85	1.32	1.2	1.12	1.06	1.26	1.29
ENBRIDGE INC	ENB.	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	0.507	0.23	0.575	0.725	0.788	0.772	0.955	1.27	1.315	1.3	1.505	1.635	1.65	1.81	1.92	2.25
FORTIS INC	FTS.	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	0.64	0.615	0.632	0.59	0.595	0.495	0.56	0.637	0.837	0.973	1.063	1.072	1.28	1.41	1.32	1.63
PACIFIC NORTHERN GAS LTD	PNG.	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	1.63	1.8	1.67	2.01	2.16	1.73	1.92	1.83	1.52	1.2	1.49	1.41	1.75	1.27	1.11	1.53
TERASEN INC	TER.1	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	0.715	0.51	0.58	0.89	0.815	0.925	1.06	1.52	1.105	1.27	1.325	1.43	@NA	@NA	@NA	@NA
TRANSCANADA CORP	TRP.	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	1.62	1.6	1.75	1.88	1.85	1.25	0.91	1.03	1.42	1.56	1.66	2.02	2.25	2.05	2.12	2.26
WESTCOAST ENERGY INC	W.	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA	1.95	1.83	1.93	2.11	2.06	1.7	1.77	2.83	@NA	@NA	@NA	@NA	@NA	@NA	@NA	@NA

	CU	12.53	13.87	11.35	9.02	9.67	9.07	8.88	9.01	9.70	8.80	9.19	9.83	9.55	7.88	6.69	7.34	8.87	7.36	8.73	7.58	8.48	5.86	6.28	6.52	7.55
	EMA									4.12	8.98	9.41	9.55	8.12	7.22	5.44	6.99	8.11	7.19	5.11	7.18	6.56	5.88	5.66	6.53	5.88
	ENB	15.70	12.13	10.67	11.13	11.83	12.41	13.51	18.27	24.64	22.88	24.00	21.97	22.47	17.54	10.65	11.75	10.81	7.38	5.32	6.23	5.36	5.13	3.51	2.95	3.66
Earnings Yield	FTS				10.53	11.59	10.92	11.87	10.62	11.25	9.83	9.26	9.63	7.85	6.72	4.39	6.38	7.89	8.46	7.97	7.61	6.85	6.54	5.81	5.12	5.80
	PNG	15.69	12.81	11.03	11.63	12.04	12.73	14.37	12.80	10.69	8.90	8.81	8.47	10.28	9.30	6.05	9.07	15.56	17.48	8.50	9.06	7.10	8.97	6.87	6.10	9.02
	TER	15.57	14.48	10.77	9.61	16.45	12.94	12.18	12.50	3.27	9.22	6.55	8.03	14.27	5.22	6.11	7.65	10.14	6.64	6.35	5.99	5.80				
	TRP	13.82	9.86	6.93	5.41	5.33	7.43	7.59	7.81	8.95	8.33	8.84	9.63	8.77	6.86	2.79	5.07	8.49	7.39	6.95	6.74	7.29	7.63	6.09	5.99	6.68
	W	9.96	8.38	7.47	7.64	6.68	6.67	6.81	6.78	7.95	8.98	7.98	9.77	9.07	7.62	4.79	7.00	10.77								
	CU	7.24	6.80	6.75	6.61	6.81	6.60	7.00	6.93	6.79	6.02	5.96	6.07	5.27	4.31	3.66	4.00	4.45	3.70	3.56	3.78	3.68	3.08	3.42	2.65	3.06
	EMA									1.72	6.31	6.50	6.71	6.19	5.48	4.51	4.99	5.68	5.11	5.17	5.15	4.81	4.66	4.41	4.32	4.39
	ENB	5.65	4.60	4.90	4.26	4.42	4.29	4.21	5.50	35.76	7.02	6.67	6.58	5.68	4.30	3.50	3.65	3.75	3.40	3.37	3.46	3.48	3.04	3.17	3.27	3.16
Dividend Yield	FTS	6.60	6.00	6.22	6.33	6.70	6.40	6.95	6.55	6.61	5.92	6.10	6.45	5.75	4.97	4.28	5.14	5.70	4.71	3.98	3.72	3.45	2.84	2.74	3.00	3.72
	PNG	7.31	6.82	7.08	6.47	6.76	6.62	6.73	5.98	5.52	4.80	4.31	4.77	4.91	4.30	3.85	5.29	4.76	0.00	0.00	4.87	4.03	4.10	4.33	4.40	5.19
	TER	7.51	6.21	5.84	5.10	5.54	5.16	5.55	5.77	5.63	5.78	6.05	6.20	5.05	4.00	3.60	4.19	4.37	3.90	3.66	3.58	3.35				
	TRP	5.73	4.60	6.47	6.31	4.96	4.28	4.10	4.25	4.47	4.42	5.20	5.61	5.21	4.38	4.27	5.85	6.29	4.72	4.45	4.39	4.19	3.74	3.62	3.53	3.80
	W	7.35	6.18	7.18	4.85	4.77	4.23	3.81	3.99	4.64	4.05	3.88	4.52	4.86	4.44	3.96	4.65	4.72	3.63	0.80						
	CU	-5.22	20.24	6.04	3.72	-1.48	4.93	-4.54	1.98	3.77	14.15	2.70	-0.26	16.45	28.82	23.98	-4.00	-5.99	25.63	8.40	-2.09	6.69	24.04	14.70	15.39	-7.80
	EMA									-0.68	9.08	-1.92	-0.53	11.25	14.56	22.75	-8.71	-10.94	12.81	-0.27	0.41	9.52	4.19	5.68	3.36	5.31
	ENB	-9.93	33.85	1.50	14.87	-3.46	2.83	2.04	-23.52	-30.75	13.24	5.26	1.36	17.70	37.62	31.92	0.64	3.56	21.67	9.48	6.12	9.87	29.75	6.02	4.02	10.99
Average Stock Price Inc/dec	FTS	-0.78	22.73	4.66	6.93	-1.79	10.85	-3.63	9.55	-0.28	14.95	2.04	-1.21	14.55	17.76	18.32	-16.15	-8.09	22.55	23.51	14.44	12.00	31.90	18.40	11.76	-1.48
	PNG	1.98	26.66	3.72	13.55	-0.84	2.06	-1.65	16.14	11.85	26.32	11.48	-3.47	-0.86	18.84	23.08	-25.99	-44.44	-26.05	62.34	16.45	20.81	-1.73	-5.28	-1.59	-6.72
	TER	-5.87	35.69	21.92	9.50	-7.82	17.05	2.25	5.60	2.55	-2.55	-4.57	-2.39	18.53	37.27	24.30	-8.47	1.07	18.95	15.84	10.74	15.38				
	TRP	11.60	39.61	-28.88	2.59	-22.82	15.88	2.03	5.91	1.58	11.59	-7.01	0.46	16.05	27.82	2.40	-30.65	-33.56	49.93	17.76	9.64	12.54	17.74	8.25	9.10	-1.68
	W	-5.61	18.89	-18.94	20.84	1.71	12.67	11.19	-4.56	-14.03	17.58	13.10	-10.22	5.01	24.99	18.11	-12.69	-2.66	37.03	15.38						
	CU	2.01	27.03	12.79	10.33	5.34	11.53	2.46	8.90	10.57	20.17	8.66	5.81	21.72	33.13	27.64	0.00	-1.54	29.33	11.96	1.69	10.37	27.13	18.12	18.04	-4.74
	EMA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04	15.39	4.58	6.17	17.44	20.04	27.26	-3.72	-5.26	17.92	4.90	5.56	14.33	8.85	10.09	7.69	9.71
	ENB	-4.27	38.45	6.40	19.13	0.95	7.12	6.24	-18.02	5.01	20.26	11.93	7.93	23.37	41.92	35.42	4.29	7.31	25.07	12.85	9.58	13.35	32.79	9.19	7.30	14.15
Total Yield=dividend + price	FTS	5.82	28.73	10.88	13.26	4.91	17.24	3.31	16.10	6.33	20.87	8.14	5.23	20.30	22.73	22.60	-11.01	-2.39	27.26	27.49	18.16	15.45	34.74	21.14	14.77	2.23
	PNG	9.29	33.48	10.80	20.02	5.92	8.68	5.08	22.12	17.36	31.12	15.79	1.30	4.05	23.14	26.93	-20.70	-39.68	-26.05	62.34	21.31	24.83	2.37	-0.95	2.81	-1.54
	TER	1.64	41.90	27.75	14.61	-2.28	22.21	7.80	11.37	8.18	3.22	1.49	3.81	23.59	41.27	27.90	-4.27	5.44	22.85	19.50	14.32	18.73	0.00	0.00	0.00	0.00
	TRP	17.33	44.21	-22.41	8.89	-17.85	20.16	6.13	10.17	6.05	16.01	-1.82	6.07	21.26	32.20	6.67	-24.80	-27.27	54.65	22.21	14.03	16.73	21.48	11.87	12.63	2.12
	W	1.73	25.07	-11.75	25.69	6.48	16.90	15.00	-0.57	-9.39	21.63	16.99	-5.70	9.87	29.43	22.06	-8.04	2.06	40.66	16.18	0.00	0.00	0.00	0.00	0.00	0.00

Week Ending	Index	Price Earnings Ratio	Earnings Adjusted to Index	Dividend Yield Percentage	Earnings Yield
20020104W	S&P/TSX Compos	n/a	(165.09)	1.52	
20020111W	S&P/TSX Compos	n/a	(165.23)	1.54	
20020118W	S&P/TSX Compos	n/a	(164.81)	1.57	
20020125W	S&P/TSX Compos	n/a	(181.19)	1.56	
20020201W	S&P/TSX Compos	n/a	(187.19)	1.56	
20020208W	S&P/TSX Compos	n/a	(192.29)	1.60	
20020215W	S&P/TSX Compos	n/a	(195.96)	1.61	
20020222W	S&P/TSX Compos	n/a	(215.08)	1.65	
20020301W	S&P/TSX Compos	n/a	(222.63)	1.60	
20020308W	S&P/TSX Compos	n/a	(231.90)	1.57	
20020315W	S&P/TSX Compos	n/a	(244.83)	1.57	
20020322W	S&P/TSX Compos	n/a	(265.55)	1.56	
20020329W	S&P/TSX Compos	n/a	(277.20)	1.57	
20020405W	S&P/TSX Compos	n/a	(256.35)	1.58	
20020412W	S&P/TSX Compos	n/a	(253.39)	1.60	
20020419W	S&P/TSX Compos	n/a	(255.98)	1.56	
20020426W	S&P/TSX Compos	n/a	(259.63)	1.62	
20020503W	S&P/TSX Compos	n/a	(257.08)	1.61	
20020510W	S&P/TSX Compos	n/a	(257.08)	1.63	
20020517W	S&P/TSX Compos	n/a	(252.03)	1.61	
20020524W	S&P/TSX Compos	n/a	(260.95)	1.62	
20020531W	S&P/TSX Compos	n/a	(267.24)	1.62	
20020607W	S&P/TSX Compos	n/a	(231.52)	1.60	
20020614W	S&P/TSX Compos	n/a	(303.91)	1.71	
20020621W	S&P/TSX Compos	n/a	(303.19)	1.73	
20020628W	S&P/TSX Compos	n/a	(252.17)	1.72	
20020705W	S&P/TSX Compos	n/a	(243.91)	1.73	
20020712W	S&P/TSX Compos	n/a	(245.67)	1.81	
20020719W	S&P/TSX Compos	n/a	(257.82)	1.89	
20020726W	S&P/TSX Compos	n/a	(279.87)	1.95	
20020802W	S&P/TSX Compos	n/a	(278.93)	1.89	
20020809W	S&P/TSX Compos	n/a	(271.66)	1.86	
20020816W	S&P/TSX Compos	n/a	(278.62)	1.89	
20020823W	S&P/TSX Compos	68.79	96.15	1.89	1.45
20020830W	S&P/TSX Compos	69.81	94.72	1.89	1.43
20020906W	S&P/TSX Compos	73.69	87.93	1.93	1.36
20020913W	S&P/TSX Compos	73.84	87.96	1.92	1.35
20020920W	S&P/TSX Compos	69.44	89.32	2.01	1.44
20020927W	S&P/TSX Compos	65.37	93.48	2.05	1.53
20021004W	S&P/TSX Compos	66.02	89.90	2.11	1.51
20021011W	S&P/TSX Compos	66.51	89.89	2.09	1.50
20021018W	S&P/TSX Compos	70.03	90.35	1.98	1.43
20021025W	S&P/TSX Compos	60.67	105.58	1.95	1.65
20021101W	S&P/TSX Compos	60.66	104.21	1.97	1.65
20021108W	S&P/TSX Compos	63.12	101.23	1.96	1.58
20021115W	S&P/TSX Compos	63.35	101.93	1.94	1.58
20021122W	S&P/TSX Compos	56.02	117.00	1.91	1.79
20021129W	S&P/TSX Compos	59.82	109.84	1.91	1.67
20021206W	S&P/TSX Compos	57.61	114.17	1.92	1.74
20021213W	S&P/TSX Compos	44.46	149.89	1.89	2.25
20021220W	S&P/TSX Compos	43.59	150.50	1.92	2.29
20021227W	S&P/TSX Compos	42.29	155.97	1.91	2.36
20030103W	S&P/TSX Compos	43.42	155.97	1.87	2.30
20030110W	S&P/TSX Compos	43.52	156.30	1.85	2.30
20030117W	S&P/TSX Compos	41.48	162.88	1.86	2.41
20030124W	S&P/TSX Compos	39.32	169.51	1.89	2.54
20030131W	S&P/TSX Compos	33.53	195.94	1.94	2.98
20030207W	S&P/TSX Compos	31.35	206.66	1.99	3.19
20030214W	S&P/TSX Compos	30.83	210.43	2.00	3.24
20030221W	S&P/TSX Compos	34.01	192.85	1.98	2.94
20030228W	S&P/TSX Compos	33.80	193.96	1.99	2.96
20030307W	S&P/TSX Compos	31.75	200.29	2.06	3.15
20030314W	S&P/TSX Compos	27.35	230.49	2.08	3.66
20030321W	S&P/TSX Compos	28.37	230.40	2.01	3.52
20030328W	S&P/TSX Compos	27.70	230.32	2.07	3.61
20030404W	S&P/TSX Compos	29.08	219.92	2.06	3.44
20030411W	S&P/TSX Compos	28.64	224.55	2.03	3.49
20030418W	S&P/TSX Compos	29.31	222.61	2.00	3.41
20030425W	S&P/TSX Compos	28.70	227.26	2.01	3.48
20030502W	S&P/TSX Compos	27.90	237.22	1.98	3.58
20030509W	S&P/TSX Compos	25.73	258.44	1.97	3.89
20030516W	S&P/TSX Compos	26.48	254.60	1.95	3.78

Week Ending	Index	Price Earnings Ratio	Earnings Adjusted to Index	Dividend Yield Percentage	Earnings Yield
20030523W	S&P/TSX Compos	26.20	258.86	1.94	3.82
20030530W	S&P/TSX Compos	24.78	276.86	1.93	4.04
20030606W	S&P/TSX Compos	25.50	276.30	1.88	3.92
20030613W	S&P/TSX Compos	25.38	276.21	1.86	3.94
20030620W	S&P/TSX Compos	25.43	278.00	1.84	3.93
20030627W	S&P/TSX Compos	25.15	277.54	1.86	3.98
20030704W	S&P/TSX Compos	25.27	277.12	1.86	3.96
20030711W	S&P/TSX Compos	25.70	275.42	1.85	3.89
20030718W	S&P/TSX Compos	26.12	272.39	1.84	3.83
20030725W	S&P/TSX Compos	24.61	295.05	1.84	4.06
20030801W	S&P/TSX Compos	23.80	303.33	1.84	4.20
20030808W	S&P/TSX Compos	23.28	311.45	1.82	4.30
20030815W	S&P/TSX Compos	23.78	310.82	1.78	4.21
20030822W	S&P/TSX Compos	23.62	316.12	1.76	4.23
20030829W	S&P/TSX Compos	21.82	344.27	1.77	4.58
20030905W	S&P/TSX Compos	21.70	350.77	1.76	4.61
20030912W	S&P/TSX Compos	21.61	350.69	1.77	4.63
20030919W	S&P/TSX Compos	21.74	349.75	1.77	4.60
20030926W	S&P/TSX Compos	20.34	365.43	1.80	4.92
20031003W	S&P/TSX Compos	20.51	366.59	1.77	4.88
20031010W	S&P/TSX Compos	20.76	367.66	1.75	4.82
20031017W	S&P/TSX Compos	20.97	367.97	1.73	4.77
20031024W	S&P/TSX Compos	21.10	360.84	1.75	4.74
20031031W	S&P/TSX Compos	20.79	373.89	1.72	4.81
20031107W	S&P/TSX Compos	21.13	372.04	1.70	4.73
20031114W	S&P/TSX Compos	20.96	369.91	1.72	4.77
20031121W	S&P/TSX Compos	21.04	369.87	1.72	4.75
20031128W	S&P/TSX Compos	20.02	392.62	1.72	5.00
20031205W	S&P/TSX Compos	18.97	421.24	1.71	5.27
20031212W	S&P/TSX Compos	18.97	420.61	1.72	5.27
20031219W	S&P/TSX Compos	19.29	420.58	1.69	5.18
20031226W	S&P/TSX Compos	19.51	416.97	1.66	5.13
20040102W	S&P/TSX Compos	19.76	419.62	1.63	5.06
20040109W	S&P/TSX Compos	19.90	419.62	1.61	5.03
20040116W	S&P/TSX Compos	20.25	420.81	1.59	4.94
20040123W	S&P/TSX Compos	20.47	420.44	1.57	4.89
20040130W	S&P/TSX Compos	20.22	421.35	1.62	4.95
20040206W	S&P/TSX Compos	21.01	411.24	1.60	4.76
20040213W	S&P/TSX Compos	20.67	420.54	1.59	4.84
20040220W	S&P/TSX Compos	20.15	428.92	1.61	4.96
20040227W	S&P/TSX Compos	20.48	429.15	1.62	4.88
20040305W	S&P/TSX Compos	20.01	442.13	1.62	5.00
20040312W	S&P/TSX Compos	19.52	440.16	1.67	5.12
20040319W	S&P/TSX Compos	19.17	447.71	1.68	5.22
20040326W	S&P/TSX Compos	19.04	446.91	1.68	5.25
20040402W	S&P/TSX Compos	19.73	445.99	1.63	5.07
20040409W	S&P/TSX Compos	19.78	446.56	1.62	5.06
20040416W	S&P/TSX Compos	19.50	445.96	1.65	5.13
20040423W	S&P/TSX Compos	19.51	444.24	1.66	5.13
20040430W	S&P/TSX Compos	18.82	437.99	1.74	5.31
20040507W	S&P/TSX Compos	19.10	433.27	1.74	5.24
20040514W	S&P/TSX Compos	18.90	433.19	1.76	5.29
20040521W	S&P/TSX Compos	18.92	433.88	1.76	5.29
20040528W	S&P/TSX Compos	18.68	446.80	1.75	5.35
20040604W	S&P/TSX Compos	18.58	449.43	1.78	5.38
20040611W	S&P/TSX Compos	18.59	450.01	1.78	5.38
20040618W	S&P/TSX Compos	18.82	449.88	1.76	5.31
20040625W	S&P/TSX Compos	19.17	443.31	1.73	5.22
20040702W	S&P/TSX Compos	19.04	445.77	1.73	5.25
20040709W	S&P/TSX Compos	19.04	445.08	1.73	5.25
20040716W	S&P/TSX Compos	18.94	440.89	1.76	5.28
20040723W	S&P/TSX Compos	19.01	441.07	1.76	5.26
20040730W	S&P/TSX Compos	19.24	439.70	1.75	5.20
20040806W	S&P/TSX Compos	18.64	438.73	1.83	5.36
20040813W	S&P/TSX Compos	18.60	439.50	1.85	5.38
20040820W	S&P/TSX Compos	18.69	445.96	1.81	5.35
20040827W	S&P/TSX Compos	18.65	446.79	1.83	5.36
20040903W	S&P/TSX Compos	18.63	447.98	1.83	5.37
20040910W	S&P/TSX Compos	18.67	448.25	1.82	5.36
20040917W	S&P/TSX Compos	19.01	448.66	1.79	5.26
20040924W	S&P/TSX Compos	19.25	446.13	1.76	5.19
20041001W	S&P/TSX Compos	19.62	445.73	1.72	5.10

Week Ending	Index	Price Earnings Ratio	Earnings Adjusted to Index	Dividend Yield Percentage	Earnings Yield
20041008W	S&P/TSX Compos	19.75	446.39	1.71	5.06
20041015W	S&P/TSX Compos	19.63	447.74	1.72	5.09
20041022W	S&P/TSX Compos	19.07	460.41	1.72	5.24
20041029W	S&P/TSX Compos	18.74	473.45	1.71	5.34
20041105W	S&P/TSX Compos	18.52	478.86	1.70	5.40
20041112W	S&P/TSX Compos	18.34	485.07	1.70	5.45
20041119W	S&P/TSX Compos	18.42	486.33	1.69	5.43
20041126W	S&P/TSX Compos	18.46	490.73	1.67	5.42
20041203W	S&P/TSX Compos	18.57	487.56	1.70	5.39
20041210W	S&P/TSX Compos	18.41	487.01	1.73	5.43
20041217W	S&P/TSX Compos	18.72	487.20	1.70	5.34
20041224W	S&P/TSX Compos	19.04	487.70	1.66	5.25
20041231W	S&P/TSX Compos	18.81	491.46	1.67	5.32
20050107W	S&P/TSX Compos	18.33	491.28	1.72	5.46
20050114W	S&P/TSX Compos	18.44	491.28	1.71	5.42
20050121W	S&P/TSX Compos	18.50	491.15	1.70	5.41
20050128W	S&P/TSX Compos	18.61	491.15	1.69	5.37
20050204W	S&P/TSX Compos	18.52	505.23	1.66	5.40
20050211W	S&P/TSX Compos	18.66	512.14	1.64	5.36
20050218W	S&P/TSX Compos	18.78	514.43	1.62	5.32
20050225W	S&P/TSX Compos	17.79	547.51	1.65	5.62
20050304W	S&P/TSX Compos	17.99	551.67	1.64	5.56
20050311W	S&P/TSX Compos	17.62	549.87	1.67	5.68
20050318W	S&P/TSX Compos	17.87	545.73	1.66	5.60
20050325W	S&P/TSX Compos	17.59	542.06	1.69	5.69
20050401W	S&P/TSX Compos	17.70	544.45	1.66	5.65
20050408W	S&P/TSX Compos	17.55	548.39	1.66	5.70
20050415W	S&P/TSX Compos	16.90	549.08	1.73	5.92
20050422W	S&P/TSX Compos	17.17	545.43	1.73	5.82
20050429W	S&P/TSX Compos	17.24	543.52	1.75	5.80
20050506W	S&P/TSX Compos	17.76	536.17	1.75	5.63
20050513W	S&P/TSX Compos	17.30	536.19	1.79	5.78
20050520W	S&P/TSX Compos	17.39	543.62	1.77	5.75
20050527W	S&P/TSX Compos	17.67	544.54	1.78	5.66
20050603W	S&P/TSX Compos	17.68	547.11	1.78	5.66
20050610W	S&P/TSX Compos	17.87	547.71	1.76	5.60
20050617W	S&P/TSX Compos	18.14	548.48	1.73	5.51
20050624W	S&P/TSX Compos	18.69	534.88	1.71	5.35
20050701W	S&P/TSX Compos	18.53	534.52	1.72	5.40
20050708W	S&P/TSX Compos	18.99	535.87	1.68	5.27
20050715W	S&P/TSX Compos	18.88	537.55	1.68	5.30
20050722W	S&P/TSX Compos	19.28	538.22	1.64	5.19
20050729W	S&P/TSX Compos	18.99	548.83	1.65	5.27
20050805W	S&P/TSX Compos	18.91	557.86	1.63	5.29
20050812W	S&P/TSX Compos	19.20	556.38	1.61	5.21
20050819W	S&P/TSX Compos	18.73	560.81	1.64	5.34
20050826W	S&P/TSX Compos	19.40	540.40	1.64	5.15
20050902W	S&P/TSX Compos	19.87	542.12	1.61	5.03
20050909W	S&P/TSX Compos	20.12	541.68	1.59	4.97
20050916W	S&P/TSX Compos	20.31	541.27	1.58	4.92
20050923W	S&P/TSX Compos	20.13	541.56	1.58	4.97
20050930W	S&P/TSX Compos	20.33	541.52	1.57	4.92
20051007W	S&P/TSX Compos	19.65	539.99	1.63	5.09
20051014W	S&P/TSX Compos	19.26	544.65	1.65	5.19
20051021W	S&P/TSX Compos	18.96	542.91	1.69	5.27
20051028W	S&P/TSX Compos	19.21	536.79	1.69	5.21
20051104W	S&P/TSX Compos	19.13	557.97	1.63	5.23
20051111W	S&P/TSX Compos	19.52	546.65	1.66	5.12
20051118W	S&P/TSX Compos	19.70	544.35	1.66	5.08
20051125W	S&P/TSX Compos	20.23	543.78	1.61	4.94
20051202W	S&P/TSX Compos	19.99	550.45	1.62	5.00
20051209W	S&P/TSX Compos	20.18	551.58	1.60	4.96
20051216W	S&P/TSX Compos	20.07	555.01	1.61	4.98
20051223W	S&P/TSX Compos	19.96	563.52	2.00	5.01
20051230W	S&P/TSX Compos	19.94	565.38	1.99	5.02
20060106W	S&P/TSX Compos	20.62	563.57	1.93	4.85
20060113W	S&P/TSX Compos	20.58	563.87	1.94	4.86
20060120W	S&P/TSX Compos	20.58	563.87	1.94	4.86
20060127W	S&P/TSX Compos	20.46	579.46	1.91	4.89
20060203W	S&P/TSX Compos	20.50	582.19	1.92	4.88
20060210W	S&P/TSX Compos	19.99	582.76	1.99	5.00
20060217W	S&P/TSX Compos	20.15	583.39	1.97	4.96

Week Ending	Index	Price Earnings Ratio	Earnings Adjusted to Index	Dividend Yield Percentage	Earnings Yield
20060224W	S&P/TSX Compos	19.61	602.12	1.98	5.10
20060303W	S&P/TSX Compos	19.72	607.55	1.97	5.07
20060310W	S&P/TSX Compos	19.25	614.86	1.99	5.19
20060317W	S&P/TSX Compos	19.55	613.79	1.96	5.12
20060324W	S&P/TSX Compos	18.48	655.46	2.28	5.41
20060331W	S&P/TSX Compos	19.50	621.14	2.28	5.13
20060407W	S&P/TSX Compos	19.75	619.81	2.25	5.06
20060414W	S&P/TSX Compos	19.78	619.36	2.26	5.06
20060421W	S&P/TSX Compos	20.33	611.90	2.22	4.92
20060428W	S&P/TSX Compos	19.26	633.75	2.27	5.19
20060505W	S&P/TSX Compos	18.99	646.29	2.29	5.27
20060512W	S&P/TSX Compos	18.25	659.54	2.35	5.48
20060519W	S&P/TSX Compos	17.48	660.45	2.45	5.72
20060526W	S&P/TSX Compos	17.77	661.96	2.44	5.63
20060602W	S&P/TSX Compos	17.87	665.67	2.42	5.60
20060609W	S&P/TSX Compos	17.78	640.74	2.53	5.62
20060616W	S&P/TSX Compos	17.45	642.43	2.57	5.73
20060623W	S&P/TSX Compos	17.52	641.90	2.54	5.71
20060630W	S&P/TSX Compos	18.08	642.13	2.46	5.53
20060707W	S&P/TSX Compos	18.11	642.32	2.46	5.52
20060714W	S&P/TSX Compos	18.09	643.06	2.48	5.53
20060721W	S&P/TSX Compos	17.47	653.67	2.53	5.72
20060728W	S&P/TSX Compos	17.23	686.22	2.44	5.80
20060804W	S&P/TSX Compos	16.63	717.78	2.43	6.01
20060811W	S&P/TSX Compos	16.50	723.83	2.43	6.06
20060818W	S&P/TSX Compos	16.76	718.85	2.44	5.97
20060825W	S&P/TSX Compos	16.72	724.96	2.46	5.98
20060901W	S&P/TSX Compos	16.44	738.54	2.45	6.08
20060908W	S&P/TSX Compos	16.07	738.68	2.51	6.22
20060915W	S&P/TSX Compos	15.72	741.58	2.56	6.36
20060922W	S&P/TSX Compos	15.71	737.32	2.59	6.37
20060929W	S&P/TSX Compos	15.96	737.06	2.55	6.27
20061006W	S&P/TSX Compos	15.83	738.59	2.55	6.32
20061013W	S&P/TSX Compos	16.11	739.37	2.50	6.21
20061020W	S&P/TSX Compos	16.21	742.37	2.47	6.17
20061027W	S&P/TSX Compos	16.14	760.18	2.44	6.20
20061103W	S&P/TSX Compos	15.74	777.77	2.50	6.35
20061110W	S&P/TSX Compos	15.91	775.42	2.48	6.29
20061117W	S&P/TSX Compos	15.81	782.50	2.47	6.33
20061124W	S&P/TSX Compos	16.10	784.39	2.42	6.21
20061201W	S&P/TSX Compos	15.61	817.20	2.40	6.41
20061208W	S&P/TSX Compos	15.80	816.67	2.39	6.33
20061215W	S&P/TSX Compos	15.69	819.98	2.40	6.37
20061222W	S&P/TSX Compos	15.60	815.34	2.46	6.41
20061229W	S&P/TSX Compos	15.78	818.27	2.42	6.34
20070105W	S&P/TSX Compos	15.25	818.23	2.51	6.56
20070112W	S&P/TSX Compos	15.45	820.62	2.47	6.47
20070119W	S&P/TSX Compos	15.49	820.90	2.44	6.46
20070126W	S&P/TSX Compos	15.83	819.99	2.39	6.32
20070202W	S&P/TSX Compos	16.16	811.26	2.37	6.19
20070209W	S&P/TSX Compos	15.90	823.01	2.39	6.29
20070216W	S&P/TSX Compos	16.32	815.80	2.37	6.13
20070223W	S&P/TSX Compos	16.56	805.78	2.38	6.04
20070302W	S&P/TSX Compos	15.72	818.02	2.49	6.36
20070309W	S&P/TSX Compos	16.28	802.23	2.46	6.14
20070316W	S&P/TSX Compos	16.08	798.06	2.52	6.22
20070323W	S&P/TSX Compos	16.70	792.69	2.44	5.99
20070330W	S&P/TSX Compos	16.30	807.80	2.46	6.13
20070406W	S&P/TSX Compos	16.57	810.08	2.41	6.04
20070413W	S&P/TSX Compos	16.67	814.71	2.38	6.00
20070420W	S&P/TSX Compos	16.76	815.28	2.36	5.97
20070427W	S&P/TSX Compos	16.79	811.69	2.38	5.96
20070504W	S&P/TSX Compos	17.39	792.00	2.37	5.75
20070511W	S&P/TSX Compos	17.68	791.94	2.34	5.66
20070518W	S&P/TSX Compos	17.68	797.95	2.32	5.66
20070525W	S&P/TSX Compos	17.60	796.68	2.34	5.68
20070601W	S&P/TSX Compos	17.66	799.70	2.34	5.66
20070608W	S&P/TSX Compos	17.26	799.39	2.40	5.79
20070615W	S&P/TSX Compos	17.68	799.57	2.34	5.66
20070622W	S&P/TSX Compos	17.39	804.44	2.37	5.75
20070629W	S&P/TSX Compos	17.32	802.83	2.39	5.77
20070706W	S&P/TSX Compos	17.56	803.81	2.35	5.69

Week Ending	Index	Price Earnings Ratio	Earnings Adjusted to Index	Dividend Yield Percentage	Earnings Yield
20070713W	S&P/TSX Compos	17.91	809.47	2.30	5.58
20070720W	S&P/TSX Compos	17.90	814.76	2.29	5.59
20070727W	S&P/TSX Compos	17.24	797.49	2.44	5.80
20070803W	S&P/TSX Compos	17.20	788.54	2.48	5.81
20070810W	S&P/TSX Compos	17.32	777.44	2.50	5.77
20070817W	S&P/TSX Compos	17.05	765.35	2.57	5.87
20070824W	S&P/TSX Compos	17.58	769.10	2.51	5.69
20070831W	S&P/TSX Compos	17.65	773.80	2.49	5.67
20070907W	S&P/TSX Compos	17.82	765.93	2.49	5.61
20070914W	S&P/TSX Compos	18.08	765.85	2.46	5.53
20070921W	S&P/TSX Compos	18.22	765.00	2.43	5.49
20070928W	S&P/TSX Compos	18.50	761.99	2.40	5.41
20071005W	S&P/TSX Compos	18.68	761.82	2.37	5.35
20071012W	S&P/TSX Compos	18.73	763.11	2.36	5.34
20071019W	S&P/TSX Compos	18.26	766.99	2.42	5.48
20071026W	S&P/TSX Compos	18.35	779.07	2.37	5.45
20071102W	S&P/TSX Compos	18.72	767.20	2.42	5.34
20071109W	S&P/TSX Compos	18.51	749.23	2.50	5.40
20071116W	S&P/TSX Compos	18.27	740.61	2.57	5.47
20071123W	S&P/TSX Compos	18.23	738.70	2.59	5.49
20071130W	S&P/TSX Compos	18.57	737.19	2.55	5.39
20071207W	S&P/TSX Compos	18.70	741.48	2.49	5.35
20071214W	S&P/TSX Compos	18.45	741.34	2.53	5.42
20071221W	S&P/TSX Compos	18.34	741.34	2.54	5.45
20071228W	S&P/TSX Compos	18.45	749.07	2.50	5.42
20080104W	S&P/TSX Compos	18.31	752.37	2.51	5.46
20080111W	S&P/TSX Compos	17.91	761.05	2.54	5.58
20080118W	S&P/TSX Compos	16.63	766.00	2.71	6.01
20080125W	S&P/TSX Compos	16.60	776.70	2.68	6.02
20080201W	S&P/TSX Compos	17.01	783.14	2.63	5.88
20080208W	S&P/TSX Compos	16.38	793.14	2.72	6.11
20080215W	S&P/TSX Compos	16.54	799.71	2.72	6.05
20080222W	S&P/TSX Compos	16.97	800.43	2.68	5.89
20080229W	S&P/TSX Compos	17.10	794.18	2.69	5.85
20080307W	S&P/TSX Compos	17.97	739.23	2.75	5.56
20080314W	S&P/TSX Compos	18.00	736.18	2.75	5.56
20080321W	S&P/TSX Compos	17.09	747.66	2.88	5.85
20080328W	S&P/TSX Compos	17.70	747.54	2.77	5.65
20080404W	S&P/TSX Compos	18.13	754.08	2.68	5.52
20080411W	S&P/TSX Compos	18.30	747.87	2.68	5.46
20080418W	S&P/TSX Compos	17.36	820.04	2.57	5.76
20080425W	S&P/TSX Compos	17.27	816.49	2.55	5.79
20080502W	S&P/TSX Compos	17.20	830.39	2.56	5.81
20080509W	S&P/TSX Compos	17.34	837.37	2.51	5.77
20080516W	S&P/TSX Compos	17.54	854.26	2.45	5.70
20080523W	S&P/TSX Compos	17.26	852.81	2.49	5.79
20080530W	S&P/TSX Compos	17.70	831.14	2.50	5.65
20080606W	S&P/TSX Compos	18.13	825.90	2.49	5.52
20080613W	S&P/TSX Compos	17.83	828.93	2.59	5.61
20080620W	S&P/TSX Compos	17.59	829.03	2.62	5.69
20080627W	S&P/TSX Compos	17.48	821.32	2.66	5.72
20080704W	S&P/TSX Compos	17.06	821.24	2.73	5.86
20080711W	S&P/TSX Compos	16.69	821.41	2.78	5.99
20080718W	S&P/TSX Compos	16.31	828.93	2.83	6.13
20080725W	S&P/TSX Compos	16.52	809.99	2.94	6.05
20080801W	S&P/TSX Compos	16.24	830.83	2.95	6.16
20080808W	S&P/TSX Compos	16.15	826.26	3.03	6.19
20080815W	S&P/TSX Compos	15.90	823.67	3.08	6.29
20080822W	S&P/TSX Compos	16.40	819.96	2.99	6.10
20080829W	S&P/TSX Compos	17.01	809.38	2.95	5.88
20080905W	S&P/TSX Compos	15.85	808.63	3.16	6.31
20080912W	S&P/TSX Compos	15.67	814.82	3.15	6.38
20080919W	S&P/TSX Compos	15.88	813.00	3.11	6.30
20080926W	S&P/TSX Compos	14.99	809.13	3.32	6.67
20081003W	S&P/TSX Compos	13.35	809.13	3.74	7.49
20081010W	S&P/TSX Compos	11.16	812.40	4.49	8.96
20081017W	S&P/TSX Compos	11.76	812.85	4.24	8.50
20081024W	S&P/TSX Compos	10.99	846.01	4.38	9.10
20081031W	S&P/TSX Compos	11.34	860.92	3.85	8.82
20081107W	S&P/TSX Compos	10.60	904.89	3.90	9.43
20081114W	S&P/TSX Compos	10.28	880.66	4.14	9.73
20081121W	S&P/TSX Compos	9.57	852.06	4.61	10.45

Week Ending	Index	Price Earnings Ratio	Earnings Adjusted to Index	Dividend Yield Percentage	Earnings Yield
20081128W	S&P/TSX Compos	10.85	854.32	4.02	9.22
20081205W	S&P/TSX Compos	9.56	849.35	4.62	10.46
20081212W	S&P/TSX Compos	10.13	840.30	4.39	9.87
20081219W	S&P/TSX Compos	10.17	841.07	4.31	9.83
20081226W	S&P/TSX Compos	9.99	832.18	4.35	10.01
20090102W	S&P/TSX Compos	11.09	832.79	3.92	9.02
20090109W	S&P/TSX Compos	10.94	830.48	3.99	9.14
20090116W	S&P/TSX Compos	10.19	875.28	3.99	9.81
20090123W	S&P/TSX Compos	9.81	879.50	4.09	10.19
20090130W	S&P/TSX Compos	10.34	840.95	3.92	9.67
20090206W	S&P/TSX Compos	10.77	836.76	3.77	9.29
20090213W	S&P/TSX Compos	10.71	809.90	3.91	9.34
20090220W	S&P/TSX Compos	10.60	749.98	4.25	9.43
20090227W	S&P/TSX Compos	11.14	729.37	4.17	8.98
20090306W	S&P/TSX Compos	10.49	723.74	4.41	9.53
20090313W	S&P/TSX Compos	11.81	702.80	4.00	8.47
20090320W	S&P/TSX Compos	12.11	702.39	3.87	8.26
20090327W	S&P/TSX Compos	12.63	698.50	3.70	7.92

For the weekly periods where P/ ratio is N/A, this indicates the Earnings were negative.
P/E is not calcualted if the earnings are negative.

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Attachment 65.3

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

Company	Dividend Paid July 2008-June 2009	Avg. Monthly High/Low Prices Jul 2008-Jun 2009	Expected Dividend Yield [1/]	Average I/B/E/S Long-Term EPS Forecasts Jul 2008 to Jun 2008	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.70	30.29	5.9	4.6	10.5
Consolidated Edison	2.35	38.95	6.2	2.6	8.8
Dominion Resources	1.67	36.01	5.0	7.8	12.8
Duke Energy	0.92	15.40	6.2	4.5	10.7
FPL	1.84	52.37	3.8	9.8	13.7
New Jersey Resources	1.21	35.02	3.7	6.4	10.1
Northwest Nat. Gas	1.56	44.84	3.6	4.8	8.4
NSTAR	1.45	32.56	4.7	6.4	11.1
Piedmont Natural Gas	1.06	27.12	4.2	7.0	11.2
Scana	1.86	33.82	5.8	5.0	10.8
Southern Co.	1.70	33.35	5.4	5.4	10.8
Vectren	1.33	24.77	5.7	6.1	11.8
WGL Holdings Inc.	1.43	32.05	4.7	4.1	8.8
Mean	**1.54**	**33.58**	**5.0**	**5.7**	**10.7**
Median	**1.56**	**33.35**	**5.0**	**5.4**	**10.8**
Standard Deviation					**1.52**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

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

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF U.S. GAS AND ELECTRIC UTILITIES (BASED ON VALUE LINE LONG TERM EPS GROWTH RATES)

Company	Dividend Paid July 2008-June 2009	Avg. Monthly High/Low Prices Jul 2008-Jun 2009	Expected Dividend Yield [1/]	*Value Line* Long-Term EPS Forecasts Past 4 Quarterly Reports	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.70	30.29	5.8	3.1	8.9
Consolidated Edison	2.35	38.95	6.1	1.4	7.5
Dominion Resources	1.67	36.01	5.1	10.6	15.7
Duke Energy	0.92	15.40	6.3	5.1	11.4
FPL	1.84	52.37	3.8	9.9	13.7
New Jersey Resources	1.21	35.02	3.7	7.4	11.1
Northwest Nat. Gas	1.56	44.84	3.7	6.5	10.2
NSTAR	1.45	32.56	4.8	7.6	12.4
Piedmont Natural Gas	1.06	27.12	4.2	7.0	11.2
Scana	1.86	33.82	5.7	4.3	10.0
Southern Co.	1.70	33.35	5.3	5.0	10.3
Vectren	1.33	24.77	5.6	4.9	10.5
WGL Holdings Inc.	1.43	32.05	4.6	3.8	8.4
Mean	**1.54**	**33.58**	**5.0**	**5.9**	**10.9**
Median	**1.56**	**33.35**	**5.1**	**5.1**	**10.5**
Standard Deviation					**2.19**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight and *Value Line (various issues)*

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

Company	Most Recent Dividend Paid as of July 1	Avg. High/Low Prices June 2009	Expected Dividend Yield [1/]	I/B/E/S June 2009 (Yahoo)	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.72	30.77	5.8	4.3	10.1
Consolidated Edison	2.36	36.44	6.6	2.5	9.1
Dominion Resources	1.75	32.62	5.7	6.6	12.3
Duke Energy	0.92	14.37	6.7	3.9	10.6
FPL	1.89	56.70	3.7	9.8	13.5
New Jersey Resources	1.24	35.49	3.7	7.0	10.7
Northwest Nat. Gas	1.58	44.37	3.7	4.8	8.5
NSTAR	1.50	30.91	5.2	6.7	11.8
Piedmont Natural Gas	1.08	24.11	4.8	6.8	11.6
Scana	1.88	31.31	6.3	5.4	11.7
Southern Co.	1.75	30.23	6.1	5.3	11.4
Vectren	1.34	23.38	6.1	6.9	13.0
WGL Holdings Inc.	1.47	31.26	4.9	4.0	8.9
Mean	**1.58**	**32.46**	**5.3**	**5.7**	**11.0**
Median	**1.58**	**31.26**	**5.7**	**5.4**	**11.4**
Standard Deviation					**1.56**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF
U.S. GAS AND ELECTRIC UTILITIES
(BASED ON VALUE LINE LONG TERM EPS GROWTH RATES)

Company	**Most Recent Dividend Paid as of July 1**	**Avg. High/Low Prices June 2009**	**Expected Dividend Yield [1/]**	***Value Line* Most Recent EPS Growth Forecast**	**DCF Cost of Equity [2/]**
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.72	30.77	5.8	3.5	9.3
Consolidated Edison	2.36	36.44	6.6	2.5	9.1
Dominion Resources	1.75	32.62	5.8	8.0	13.8
Duke Energy	0.92	14.37	6.7	5.0	11.7
FPL	1.89	56.70	3.7	10.0	13.7
New Jersey Resources	1.24	35.49	3.7	6.0	9.7
Northwest Nat. Gas	1.58	44.37	3.7	5.0	8.7
NSTAR	1.50	30.91	5.2	8.0	13.2
Piedmont Natural Gas	1.08	24.11	4.7	6.0	10.7
Scana	1.88	31.31	6.2	4.0	10.2
Southern Co.	1.75	30.23	6.1	4.5	10.6
Vectren	1.34	23.38	6.0	5.5	11.5
WGL Holdings Inc.	1.47	31.26	4.9	4.0	8.9
Mean	**1.58**	**32.46**	**5.3**	**5.5**	**10.9**
Median	**1.58**	**31.26**	**5.8**	**5.0**	**10.6**
Standard Deviation					**1.80**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight and *Value Line (various issues)*

Attachment 74.3

Attachment BCUC 74.3

Company	Operating LDCs	Jurisdiction	WNA	Decoupling	Stabilization	SFV	Base Customer Charge		Notes
							Residential	Gen. Serv.	
AGL Resources	Atlanta Gas Light	Georgia	✓			✓			SFV - all fixed costs (all of the LDC's costs) are recovered through fixed charges. Each customer is assigned a Design Day Demand (DDD) factor based on historic consumption or engineering estimates. Revenue requirements in excess of revenues recovered through customer charges are allocated by DDD factors
	Virginia Natural Gas	Virginia	✓	✓			$9.78	$12.78	Weather normalization adjustment adds a credit or surcharge to adjust for warmer or colder than normal weather
	Elizabethtown Gas	New Jersey	✓	✓			$7.55	$16.15	Decoupling authorized by last session of the General Assembly. Current cases pending in VA.
	Florida Cities Gas	Florida					$8.00	$9.50	
	Chattanooga Gas	Tennessee	✓				$12-$10		
	Elkton Gas	Maryland	✓	✓					
Atmos Energy		Georgia	✓			✓	$7.00	$12.00	
		Virginia	✓	✓			$7.35	$16.25	
		Kentucky	✓				$9.35	$25.00	
		Tennessee	✓				$10-Summer, $13-Winter	$27.50	
		Mississippi	✓		✓		$6.95	$11.27	
		Louisiana	✓		✓		$11.70	$19.49	
		Louisiana (Trans LA)					$12.00	$12.00	
		Texas (Mid-Tex)	✓		✓		$10.69	$20.28	
		Texas (West Texas)					$10.08	$18.52	
		Texas (Amarillo)					$9.50	$15.00	
		Texas (Lubbock)					$9.95	$15.75	
		Texas (Fritch/Sanford)					$3.20	$3.20	
		Texas (Dalhart/Channing)					$4.30	$4.30	
		Colorado		✓			$9.00	$21.50	
		Kansas	✓	✓ (P)			$8.00	$16.00	
		Missouri (Southeast)				✓	$13.92	$75.00	
		Missouri (Northeast)					$20.61	$75.00	
		Missouri (West)					$19.43	$75.00	
		Iowa					$7.95	$13.00	
		Illinois		✓			$9.90	$25.00	
Energen	Alabama Gas Corporation (Alagasco)	Alabama	✓		✓				Rate stabilization and equalization - adjustment to rate to true-up actual revenues to authorized revenues
Equitable Resources	Equitable Gas Company	Pennsylvania	✓				$11.65		
		West Virginia					$6.50	$10.00	
		Kentucky					$7.50		
Laclede Group	Laclede Gas Company	Missouri	✓			✓	$15.93		
National Fuel Gas	National Fuel Gas Distribution Corp.	New York	✓	✓			$15.54		
		Pennsylvania	✓				$12.00		
New Jersey Resources	New Jersey Natural Gas	New Jersey	✓	✓			$6.60		Conservation incentive program - an adjustment to the volumetric rates for each customer class to true-up actual per-customer revenues to projected per-customer revenues
Nicor	Nicor Gas	Illinois		✓			$8.40		
Northwest Natural Gas		Oregon	✓	✓			$6.00		1) Partial decoupling mechanism - each month the company will calculate the difference between weather-normalized usage and the calculated baseline usage for each affected customer group. Resulting usage differential (debit or refund) shall be multiplied by the per therm distribution margin for applicable customer group. 2) Weather adjusted rate mechanism - adjustment allows the company to recover its fixed costs by either raising rates when weather is unusually warm or lowering rates when weather is unusually cold
		Washington		✓			$5.00	$2.00	
ONEOK	Kansas Gas Service	Kansas	✓	✓ (P)			$12.25	$23.35	
	Oklahoma Natural Gas	Oklahoma	✓		✓		$9.00	$15.00	
	Texas Gas Service	Texas	✓		✓		$7.15		

Company	Operating LDCs	Jurisdiction	WNA	Decoupling	Stabilization	SFV	Residential	Gen. Serv.	Notes
Piedmont Natural Gas		North Carolina	✓	✓			$10.00	$22.00	Customer utilization tracker - modify rates if under-collected; refund for over-collections. Requires a conservation program, to which Piedmont must contribute $500,000 annually.
		South Carolina	✓		✓		$10.00	$22.00	
		Tennessee	✓				$13-$10	$29.00	
Questar	Questar Gas	Utah	✓	✓					1) Conservation enabling tariff - the company may file at least twice annually for an adjustment to block rates to true-up revenues. 2) Weather normalization adjustment adds a credit or a surcharge to adjust for warmer or colder than normal weather
		Idaho							
		Wyoming	✓						
South Jersey Industries	South Jersey Gas	New Jersey	✓	✓			$7.76	$18.73	Conservation incentive program - adjustment (credit or surcharge) to true-up actual to authorized revenues
Southwest Gas Corp.		Arizona		✓ (P)			$8.50	$21.50	
		Nevada					$8.50	$21.50	
		California	✓	✓			$8.50	$21.50	Fixed cost adjustment mechanism to true-up actual margins. Under recovery produces a rate change; over recovery produces a refund.
UGI Corp.	UGI Gas Service	Pennsylvania	✓				$8.55		
	UGI Penn Natural Gas	Pennsylvania	✓				$8.55		
WGL Holdings, Inc.	Washington Gas	Maryland	✓	✓			$10.20	$21.10	Revenue normalization adjustment - trailing two-month adjustment to either increase rates or refund customers for the difference between actual revenues and authorized revenues.
		Virginia	✓	✓			$9.00	$16.35	
		District of Columbia					$7.95	$13.15	

Attachment 78.2

EXHIBIT 13
APPENDIX 3
THE SENSITIVITY OF THE FORWARD-LOOKING REQUIRED EQUITY RISK PREMIUM ON UTILITY STOCKS TO CHANGES IN INTEREST RATES

My estimate of the required equity risk premium on utility stocks is based on studies of the discounted cash flow ("DCF") expected return on comparable groups of utilities in each month of my study period compared to the interest rate on long-term government bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation

$$RP_{COMP} = DCF_{COMP} - I_B$$

where:

RP_{COMP} = the required risk premium on an equity investment in the comparable companies,

DCF_{COMP} = average DCF expected rate of return on a portfolio of comparable companies; and

I_B = the yield to maturity on an investment in long-term U.S. Treasury bonds.

<u>Electric Company Ex Ante Risk Premium Analysis</u>. For my electric company ex ante risk premium analysis, I began with the Moody's group of 24 electric companies shown in Table 1. I used the Moody's group of electric companies because they are a widely followed group of electric utilities, and use of this constant group greatly simplified the data collection task required to estimate the ex ante risk premium over the months of my study. Simplifying the data collection task was desirable because the ex ante risk premium approach requires that the DCF model be estimated for every company in every month of the study period. Exhibit 5 displays the average DCF expected return on an investment in the portfolio of electric companies and the yield to maturity on long-term Treasury bonds in each month of the study.

Previous studies have shown that the ex ante risk premium tends to vary inversely with the level of interest rates, that is, the risk premium tends to increase when interest rates decline, and decrease when interest rates go up. To test whether my studies also indicate that the ex ante risk premium varies inversely with the level of interest rates, I performed a regression analysis of the relationship between the ex ante risk premium and the yield to maturity on long-term Treasury bonds, using the equation,

$$RP_{COMP} = a + (b \times I_B) + e$$

where:

RP_{COMP}	=	risk premium on comparable company group;
I_B	=	yield to maturity on long-term U.S. Treasury bonds;
e	=	a random residual; and
a, b	=	coefficients estimated by the regression procedure.

Regression analysis assumes that the statistical residuals from the regression equation are random. My examination of the residuals revealed that there is a significant probability that the residuals are serially correlated (non-zero serial correlation indicates that the residual in one time period tends to be correlated with the residual in the previous time period). Therefore, I made adjustments to my data to correct for the possibility of serial correlation in the residuals.

The common procedure for dealing with serial correlation in the residuals is to estimate the regression coefficients in two steps. First, a multiple regression analysis is used to estimate the serial correlation coefficient, *r*. Second, the estimated serial correlation coefficient is used to transform the original variables into new variables whose serial correlation is approximately zero. The regression coefficients are then re-estimated using the transformed variables as inputs in the regression equation. Based on my regression analysis of the statistical relationship between the yield to maturity on long-term Treasury bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy electric company group as compared to an investment in long-term Treasury bonds is given by the equation:

$$RP_{COMP} = 12.10 \quad - \quad -1.123 \times I_B.$$

$$(12.96) \qquad (-8.44)^{[1]} \quad R^2 = 39.07 \text{ percent.}$$

This equation suggests that the ex ante risk premium on electric utility stocks increases by more than 100 basis points when the interest rate on long-term Treasury bonds declines by

[1] The t-statistics are shown in parentheses.

100 basis points. [2] Equivalently, this regression equation suggests that the cost of equity for electric utilities declines by less than 20 basis points when the interest rate on long-term Treasury bonds declines by 100 basis points. These data demonstrate that the AAM ROE Formula, which assumes that the cost of equity declines by 75 basis points when the yield to maturity on long Canada bonds declines by 100 basis points, is not appropriate for estimating the cost of equity.

Using the 2010 forecast 3.62 percent yield to maturity on long-term Canada bonds obtained from Consensus Economics as of March 2009, the regression equation produces an ex ante risk premium equal to 8.0 percent (12.1 – 1.123 x 3.62 = 8.0).

<u>Natural Gas Company Ex Ante Risk Premium Analysis</u>. I also conducted an ex ante risk premium study applied to a natural gas proxy group and followed the procedures described above. To select my ex ante risk premium natural gas proxy group of companies, I used the same criteria that I use when estimating the DCF cost of equity, namely, I selected all the companies in Value Line's groups of natural gas companies that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) had at least three analysts included in the I/B/E/S mean growth forecast; (4) have an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3; and (5) have not announced a merger. Exhibit 6 displays the results of my ex ante risk premium study, showing the average DCF expected return on an

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[2] Dr. Vander Weide uses the yield on long-term government bonds as the interest rate in his ex ante risk premium analyses. The unusual result that the ex ante risk premium on electric utility stocks increases by more than 100 basis points when the interest rate on long-term Treasury bonds decreases is significantly affected by the unusual capital market conditions since September 2008. Since that time, the DCF cost of equity for utilities has increased at the same time that the interest rate on long-term Treasury bonds has declined significantly due to the active intervention of the U. S. Government to lower interest rates in the face of difficult economic conditions. The unusual result disappears if the interest rate on A-rated utility bonds is used in the regression rather than the interest rate on long-term Government bonds. Specifically, when the yield on A-rated utility bonds in the regression, the bond coefficient is -0.5918, indicating that the risk premium over A-rated utility bonds increases by approximately 60 basis points when the yield on A-rated utility bonds declines by 100 basis points. Using a forecasted yield on A-rated utility bonds equal to 6.32 percent in the regression equation produces a required risk premium over A-rated utility bonds equal to 5.1 percent and a cost of equity equal to 11.4 percent.

investment in the portfolio of natural gas companies and the yield to maturity on long-term Treasury bonds in each month.[3]

Based on my knowledge of the statistical relationship between the yield to maturity on long-term Treasury bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy natural gas companies as compared to an investment in long-term Treasury bonds is given by the equation:

$$RP_{COMP} = 10.26 - 7.73 \times I_B.$$
$$(15.44) \qquad (-6.20)\text{[4]} \quad R^2 = 23.40 \text{ percent}$$

This equation suggests that the ex ante risk premium on natural gas utility stocks increases by more than 75 basis points when the interest rate on long-term Treasury bonds declines by 100 basis points. Equivalently, this regression equation suggests that the cost of equity for natural gas utilities declines by less than 25 basis points when the interest rate on long-term Treasury bonds declines by 100 basis points. These data demonstrate that the AAM ROE Formula, which assumes that the cost of equity declines by 75 basis points when the yield to maturity on long Canada bonds declines by 100 basis points, is not appropriate for estimating the cost of equity.

Using the 3.62 percent forecast yield to maturity on long-term Canada bonds for 2010, the regression equation produces an ex ante risk premium equal to 7.46 percent (10.26 – 7.73 x 3.62 = 7.46).

As described above, my ex ante risk premium regression analysis indicates that the cost of equity for utilities is significantly less sensitive to interest rate changes than the AAM ROE Formula implies. Rather than declining by 75 basis points when the yield to maturity on long-term government bonds declines by 100 basis points, my analysis indicates that the cost of equity declines by significantly less than 50 basis points when interest rates decline by 100 basis points.

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[3] My two ex ante risk premium studies cover slightly different time periods, with the natural gas company risk premium study extending over a longer period of time, because I began doing an ex ante study using natural gas companies before I began performing a similar study for the electric companies.

[4] The t-statistics are shown in parentheses.

TABLE 1
MOODY'S ELECTRIC COMPANIES

American Electric Power
Constellation Energy
Progress Energy
CH Energy Group
Cinergy Corp.
Consolidated Edison Inc.
DPL Inc.
DTE Energy Co.
Dominion Resources Inc.
Duke Energy Corp.
Energy East Corp.
FirstEnergy Corp.
Reliant Energy Inc.
IDACORP. Inc.
IPALCO Enterprises Inc.
NiSource Inc.
OGE Energy Corp.
Exelon Corp.
PPL Corp.
Potomac Electric Power Co.
Public Service Enterprise Group
Southern Company
Teco Energy Inc.
Xcel Energy Inc.

Source of data: *Mergent Public Utility Manual*, August 2002. Of these 24 companies, I did not include three companies in my ex ante risk premium DCF analysis because there was insufficient data to perform a DCF analysis for most of my study period. Specifically, IPALCO merged with a company that is not in the electric utility industry; Reliant divested its electric utility operations; and CH Energy does not have any I/B/E/S analysts' estimates of long-term growth. In addition, Cinergy completed its merger with Duke Energy in 2006.

Attachment 83.1

Revised Exhibit 1 in Response to BCUC 83.1
Experienced Risk Premiums on
S&P/TSX Canadian Utilities Stock Index
1956—2008

		A	B	C	D	E	F
	Year	**S&P/TSX Canadian Utilities Stock Index Total Return**	**Yield Long-term Canada Bond**	**Risk Premium**	**Total Return TSX Composite**	**Yield Long-term Canada Bond**	**Risk Premium**
1	1956	0.17	3.63	-3.45	13.22	3.63	9.59
2	1957	-3.43	4.11	-7.54	-20.58	4.11	-24.69
3	1958	9.81	4.15	5.66	31.25	4.15	27.10
4	1959	0.21	5.08	-4.86	4.59	5.08	-0.49
5	1960	26.81	5.19	21.62	1.78	5.19	-3.40
6	1961	19.17	5.05	14.12	32.75	5.05	27.70
7	1962	-0.72	5.11	-5.83	-7.09	5.11	-12.21
8	1963	6.19	5.09	1.10	15.60	5.09	10.51
9	1964	21.59	5.18	16.41	25.43	5.18	20.25
10	1965	4.23	5.21	-0.98	6.68	5.21	1.47
11	1966	-13.17	5.69	-18.86	-7.07	5.69	-12.76
12	1967	5.07	5.94	-0.87	18.09	5.94	12.15
13	1968	7.41	6.75	0.66	22.45	6.75	15.70
14	1969	-8.62	7.58	-16.20	-0.81	7.58	-8.39
15	1970	23.34	7.91	15.43	-3.57	7.91	-11.48
16	1971	4.29	6.95	-2.66	8.01	6.95	1.06
17	1972	-0.44	7.23	-7.68	27.38	7.23	20.15
18	1973	-4.14	7.56	-11.70	0.27	7.56	-7.29
19	1974	14.38	8.90	5.48	-25.93	8.90	-34.83
20	1975	5.75	9.04	-3.28	18.48	9.04	9.45
21	1976	15.02	9.18	5.84	11.02	9.18	1.85
22	1977	19.00	8.70	10.30	10.71	8.70	2.01
23	1978	27.28	9.27	18.01	29.72	9.27	20.45
24	1979	12.61	10.21	2.40	44.77	10.21	34.56
25	1980	5.74	12.48	-6.74	30.13	12.48	17.65
26	1981	-0.55	15.22	-15.77	-10.25	15.22	-25.47
27	1982	35.90	14.26	21.65	5.54	14.26	-8.71
28	1983	40.97	11.79	29.17	35.49	11.79	23.70
29	1984	24.31	12.75	11.56	-2.39	12.75	-15.14
30	1985	10.04	11.04	-1.00	25.07	11.04	14.02
31	1986	11.48	9.52	1.96	8.95	9.52	-0.57
32	1987	1.07	9.95	-8.88	5.88	9.95	-4.07
33	1988	5.63	10.22	-4.59	11.08	10.22	0.86
34	1989	22.07	9.92	12.15	21.37	9.92	11.45
35	1990	0.58	10.85	-10.28	-14.80	10.85	-25.65
36	1991	27.02	9.76	17.25	12.02	9.76	2.25
37	1992	-2.24	8.77	-11.00	-1.43	8.77	-10.20
38	1993	23.52	7.85	15.67	32.55	7.85	24.70
39	1994	-6.04	8.63	-14.68	-0.18	8.63	-8.81
40	1995	18.44	8.28	10.16	14.53	8.28	6.25
41	1996	32.68	7.50	25.18	28.35	7.50	20.84
42	1997	37.33	6.42	30.91	14.98	6.42	8.55
43	1998	36.55	5.47	31.09	-1.58	5.47	-7.05
44	1999	-27.14	5.69	-32.83	31.71	5.69	26.02
45	2000	50.06	5.89	44.17	7.41	5.89	1.52
46	2001	10.83	5.78	5.05	-12.57	5.78	-18.35
47	2002	6.33	5.66	0.67	-12.44	5.66	-18.10
48	2003	24.94	5.28	19.66	26.72	5.28	21.45
49	2004	9.42	5.08	4.34	14.48	5.08	9.40
50	2005	38.29	4.39	33.90	24.13	4.39	19.74
51	2006	7.01	4.30	2.71	17.26	4.30	12.96
52	2007	11.89	4.34	7.55	9.83	4.34	5.50
53	2008	-20.46	4.05	-24.50	-33.00	4.05	-37.05
54	Average	11.84	7.54	4.29	10.30	7.54	2.76

Total returns from 1956 - 1998 from TSX legacy utilities total return index
Total returns from 1999 - 2008 are S&P/TSX Composite Utilities Sector (55) total return index

Attachment 84.1

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and thereby only by persons permitted to sell such securities.

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of the Corporation at Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2 (telephone (709) 737-2800) and are also available electronically at www.sedar.com. For the purpose of the Province of Québec, this simplified prospectus contains information to be completed by consulting the permanent information record. A copy of the permanent information record may be obtained without charge from the Secretary of the Corporation at the above-mentioned address and telephone number and is also available electronically at www.sedar.com. The securities being offered under this short form prospectus have not been and will not be registered under the United States Securities Act of 1933, as amended, or any state securities laws, and, except in limited circumstances, will not be offered or sold within the United States or for the account or benefit of United States persons. See ''Plan of Distribution''.*

New Issue **March 7, 2007**

SHORT FORM PROSPECTUS

FORTIS INC.

$1,001,000,000
38,500,000 Subscription Receipts, each representing the right to receive one Common Share

Fortis Inc. (''Fortis'' or the ''Corporation'') is hereby qualifying for distribution (the ''Offering'') 38,500,000 subscription receipts (the ''Subscription Receipts''), each of which will entitle the holder thereof to receive, upon satisfaction of the Release Conditions (as defined below), and without payment of additional consideration, one common share of Fortis (a ''Common Share''). The gross proceeds from the sale of the Subscription Receipts (the ''Escrowed Funds'') will be held by Computershare Trust Company of Canada, as escrow agent (the ''Escrow Agent'') and invested in short-term interest bearing or discount debt obligations issued or guaranteed by the Government of Canada or a province, or one or more of the five largest Canadian chartered banks, provided that in all cases such obligation is rated at least R1 (middle) by DBRS Limited or an equivalent rating from an equivalent rating service, pending receipt by the Corporation of all regulatory and government approvals required to finalize the acquisition (the ''Acquisition'') by the Corporation of all of the issued and outstanding shares of Terasen Inc. (''Terasen''), a wholly owned subsidiary of Kinder Morgan, Inc., including that of the British Columbia Utilities Commission, and fulfillment or waiver of all other outstanding conditions precedent to closing the Acquisition as itemized in the Acquisition Agreement (as defined below) (collectively, the ''Release Conditions''). At the time of the Acquisition, Terasen will have divested itself of its petroleum transportation operations and will only hold its natural gas distribution business and an interest in CustomerWorks Limited Partnership. See ''The Acquisition'', ''The Acquired Business'' and ''Details of the Offering''.

If the Release Conditions are satisfied prior to 5:00 p.m. (Toronto time) on November 30, 2007, the Corporation will forthwith execute and deliver a notice of satisfaction and will issue and deliver to the Escrow Agent one Common Share for each Subscription Receipt then outstanding (subject to any applicable adjustment). The Common Shares will be available for delivery commencing on the second business day after the delivery of such notice. The holders of Subscription Receipts will receive, without payment of any additional consideration, one Common Share for each Subscription Receipt held plus an amount equal to the dividends declared on the Common Shares by the Corporation, if any, for which record dates have occurred during the period from the Closing Date (as defined below) to the date of issuance of the Common Shares in respect of the Subscription Receipts. Forthwith upon the Release Conditions being satisfied and the required notice being delivered to the Escrow Agent, the Escrowed Funds, together with interest earned and income generated thereon, will be released to Fortis. In the event that the Release Conditions are not satisfied prior to 5:00 p.m. (Toronto time) on November 30, 2007, or if the Acquisition Agreement is terminated prior to such time (in either case, the ''Termination Time''), holders of Subscription Receipts shall, commencing on the second business day following the Termination Time, be entitled to receive from the Escrow Agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned or income generated on such amount. See ''Details of the Offering''.

Price: $26.00 per Subscription Receipt

	Price to the Public	**Underwriters' Fee** (1)	**Net Proceeds to the Corporation** (2)
Per Subscription Receipt	$26.00	$1.04	$24.96
Total (3)	$1,001,000,000	$40,040,000	$960,960,000

(1) One-half of the Underwriters' fee is payable at the closing of the Offering. The other half of the Underwriters' fee is payable only if the Release Conditions have been satisfied prior to the Termination Time and the required notice has been delivered to the Escrow Agent. See ''Plan of Distribution''.

(2) Net proceeds to the Corporation exclude any interest earned and income generated on the Escrowed Funds and are calculated before deducting the expenses of the Offering, estimated at $1,250,000, which, together with the Underwriters' fee, will be paid out of the general funds of Fortis. See ''Plan of Distribution''.

(3) The Corporation has granted to the Underwriters an option (the ''Over-Allotment Option''), exercisable in whole or in part at any time until 30 days following the date of closing of the Offering, to purchase at the Offering Price up to 5,775,000 additional Subscription Receipts to cover over-allotments, if any. If the Over-Allotment Option is exercised in full, the total Price to the Public, Underwriters' Fee and Net Proceeds to the Corporation will be $1,151,150,000, $46,046,000 and $1,105,104,000, respectively. See ''Plan of Distribution''. This prospectus also qualifies the grant of the Over-Allotment Option and the distribution of the securities issuable on the exercise of the Over-Allotment Option.

Underwriters' Position	**Maximum Size**	**Exercise Period**	**Exercise Price**
Over-Allotment Option	5,775,000 Subscription Receipts	Within 30 days following the closing of the Offering	$26.00 per Subscription Receipt

There is currently no market through which the Subscription Receipts may be sold and purchasers may not be able to resell securities purchased under this short form prospectus (the ''Prospectus''). This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities, and the extent of issuer regulation. See ''Risk Factors''.

The Toronto Stock Exchange (the ''TSX'') has conditionally approved the listing of the Subscription Receipts, as well as the Common Shares issuable on the exchange of the Subscription Receipts. Listing is subject to the Corporation fulfilling all of the requirements of the TSX on or before June 3, 2007. The Corporation's outstanding Common Shares are listed on the TSX under the symbol ''FTS''. On March 6, 2007, the closing price of the Common Shares on the TSX was $26.80. The Subscription Receipts will be issued and sold by Fortis to the Underwriters (as defined below) at the price of $26.00 (the ''Offering Price'') per Subscription Receipt. The Offering Price and other terms of the Offering were determined by negotiation between the Corporation and the Underwriters.

An investment in the Subscription Receipts, and the Common Shares issuable upon the exchange thereof, involves certain risks that should be considered by a prospective purchaser. See ''Risk Factors''.

CIBC World Markets Inc. (''CIBCWM''), Scotia Capital Inc. (''Scotia Capital''), TD Securities Inc. (''TD Securities''), BMO Nesbitt Burns Inc. (''BMO Nesbitt Burns''), RBC Dominion Securities Inc. (''RBCDS''), National Bank Financial Inc. (''NB Financial''), Canaccord Capital Corporation, Beacon Securities Limited and HSBC Securities (Canada) Inc. (''HSBC Securities'') are acting as underwriters (collectively, the ''Underwriters'') of the Offering. The Underwriters, as principals, conditionally offer the Subscription Receipts, subject to prior sale, if, as and when issued, sold and delivered by the Corporation to, and accepted by, the Underwriters in accordance with the terms and conditions contained in the Underwriting Agreement referred to under ''Plan of Distribution'' and subject to the approval of certain legal matters on behalf of the Corporation by Davies Ward Phillips & Vineberg LLP, Toronto and McInnes Cooper, St. John's and on behalf of the Underwriters by Stikeman Elliott LLP, Toronto. Subject to applicable laws, the Underwriters may, in connection with the Offering, effect transactions which stabilize or maintain the market price of the Subscription Receipts or the Common Shares at levels other than those which may prevail on the open market. Such transactions, if commenced, may be discontinued at any time. See ''Plan of Distribution''.

CIBCWM is an affiliate of a Canadian chartered bank that has agreed to extend credit facilities to the Corporation in connection with financing the Acquisition. CIBCWM is also acting as financial advisor to Fortis in connection with the Acquisition and receiving a fee therefor. In addition, each of CIBCWM, Scotia Capital, TD Securities, BMO Nesbitt Burns, RBCDS, NB Financial and HSBC Securities is a subsidiary of a Canadian chartered bank that has, either solely or as a member of a syndicate of financial institutions, extended credit facilities to the Corporation and/or its subsidiaries. Consequently, the Corporation may be considered a ''connected issuer'' of these Underwriters within the meaning of applicable securities legislation. See ''Plan of Distribution''.

Subscriptions for the Subscription Receipts will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the closing of the Offering will take place on or about March 15, 2007 (the ''Closing Date''), or such other date as may be agreed upon by the Corporation and the Underwriters, but not later than April 18, 2007. A book entry only certificate representing the Subscription Receipts distributed hereunder will be issued in registered form only to CDS Clearing and Depository Services Inc. (''CDS'') or its nominee and will be deposited with CDS on the Closing Date. The Corporation understands that a purchaser of Subscription Receipts will receive only a customer confirmation from the registered dealer who is a CDS participant from or through whom the Subscription Receipts are purchased. See ''Details of the Offering''.

TABLE OF CONTENTS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The Prospectus, including the documents incorporated herein by reference, contain forward-looking statements which reflect management's expectations regarding the future growth, results of operations, performance, and business prospects and opportunities of Fortis Inc. Wherever possible, words such as ''anticipate'', ''believe'', ''expect'', ''intend'' and similar expressions have been used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to the Corporation's management. Forward-looking statements involve significant risk, uncertainties and assumptions. A number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking statements. These factors should be considered carefully and prospective investors should not place undue reliance on the forward-looking statements. Although the forward-looking statements contained in the Prospectus, including the documents incorporated herein by reference, are based upon what management believes to be reasonable assumptions, the Corporation cannot assure prospective purchasers that actual results will be consistent with these forward-looking statements. These forward-looking statements are made as of the date of the Prospectus, and the Corporation assumes no obligation to update or revise them to reflect new events or circumstances.

DOCUMENTS INCORPORATED BY REFERENCE

The disclosure documents of the Corporation listed below and filed with the appropriate securities commissions or similar regulatory authorities in each of the provinces of Canada are specifically incorporated by reference into and form an integral part of this Prospectus:

(a) annual information form dated March 29, 2006 for the year ended December 31, 2005;

(b) audited comparative consolidated financial statements as at December 31, 2005 and for the years ended December 31, 2005 and 2004, together with the notes thereto and the auditors' report thereon dated January 27, 2006 as contained in the Corporation's 2005 Annual Report;

(c) Management Discussion and Analysis of financial condition and results of operations for the year ended December 31, 2005 as contained in the Corporation's 2005 Annual Report;

(d) unaudited comparative interim consolidated financial statements as at September 30, 2006 and for the three- and nine-month periods ended September 30, 2006 and 2005, together with the notes thereto;

(e) Management Discussion and Analysis of financial condition and results of operations for the three- and nine-month periods ended September 30, 2006;

(f) Management Information Circular dated March 17, 2006 prepared in connection with the Corporation's annual meeting of shareholders held on May 2, 2006;

(g) material change report dated September 15, 2006 describing the entering into of an agreement between the Corporation and a syndicate of underwriters led by BMO Nesbitt Burns Inc. for the public offering by the Corporation of 5,000,000 4.90% cumulative redeemable First Preference Shares, Series F;

(h) material change report dated January 5, 2007 describing the entering into of an agreement between the Corporation and Scotia Capital Inc. and CIBCWM for the public offering by the Corporation of 5,170,000 Common Shares;

(i) press release dated February 8, 2007 with respect to the Corporation's unaudited comparative interim consolidated financial statements as at December 31, 2006 and for the three- and twelve-month periods ended December 31, 2006 and 2005, together with the notes thereto, and with respect to the related Management Discussion and Analysis of financial condition and results of operations for the three- and twelve-month periods ended December 31, 2006; and

(j) material change report dated February 28, 2007 describing the entering into of (i) an agreement pursuant to which the Corporation will acquire all of the outstanding shares of Terasen for a purchase price of $3.7 billion, including the assumption of approximately $2.3 billion of debt, and (ii) an agreement between the Corporation, CIBCWM, Scotia Capital and TD Securities for the public offering by the Corporation of 38,500,000 subscription receipts and up to an additional 5,775,000 subscription receipts pursuant to an over-allotment option.

Any document of the type referred to in the preceding paragraph (other than any confidential material change report) subsequently filed by the Corporation with such securities commissions or regulatory authorities after the date of the Prospectus, and prior to the termination of the Offering, shall be deemed to be incorporated by reference into the Prospectus.

Any statement contained in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this Prospectus to the extent that a statement contained herein, or in any other subsequently filed document which also is incorporated or is deemed to be incorporated by reference herein, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purpose that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Prospectus.

Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of the Corporation at Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2 (telephone (709) 737-2800). These documents are also available through the Internet on the Corporation's website at www.fortisinc.com or on the Canadian System for Electronic Document Analysis and Retrieval (''SEDAR'') which can be accessed at www.sedar.com. Reference is also made to information regarding Terasen Inc. (''Terasen'') which is available through the internet at Terasen's website at www.terasen.com. The information contained on, or accessible through, any of these websites is not incorporated by reference into the Prospectus and is not, and should not be considered to be, a part of the Prospectus, unless it is explicitly so incorporated.

ELIGIBILITY FOR INVESTMENT

In the opinion of Davies Ward Phillips & Vineberg LLP, counsel to the Corporation, and Stikeman Elliott LLP, counsel to the Underwriters, the Subscription Receipts and the Common Shares issuable on the exchange of the Subscription Receipts, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) (the ''Tax Act'') for a trust governed by a registered retirement savings plan, registered retirement income fund, deferred profit sharing plan or registered education savings plan provided that, in the case of the Subscription Receipts, the Corporation deals at arm's length (within the meaning of the Tax Act) with each person who is an annuitant, beneficiary, employer or subscriber under the governing plan of such trust.

DEFINED TERMS

For an explanation of certain terms and abbreviations used in the Prospectus, reference is made to the ''Glossary of Terms''.

SUMMARY

The following information is a summary only and is to be read in conjunction with, and is qualified in its entirety by, the more detailed information appearing elsewhere in the Prospectus and in the documents incorporated by reference herein.

The Offering

Issuer:	Fortis Inc. (''Fortis'' or the ''Corporation'').
Offering:	38,500,000 subscription receipts (the ''Subscription Receipts''), each representing the right to receive one common share of Fortis (a ''Common Share'').
Amount:	\$1,001,000,000 (\$1,151,150,000 if the Over-Allotment Option is exercised in full).
Over-Allotment Option:	The Corporation has granted to the Underwriters (as defined below) an option (the ''Over-Allotment Option''), exercisable in whole or in part at any time until 30 days following the date of closing of this offering (the ''Offering''), to purchase at the Offering Price up to 5,775,000 additional Subscription Receipts to cover over-allotments, if any. See ''Plan of Distribution''.
Price:	\$26.00 per Subscription Receipt.
Date of Closing:	On or about March 15, 2007 or such date as agreed to by the Corporation and the Underwriters, but not later than April 18, 2007 (the ''Closing Date'').
Escrow of Proceeds:	The gross proceeds from the sale of the Subscription Receipts (the ''Escrowed Funds'') will be held by Computershare Trust Company of Canada, as escrow agent (the ''Escrow Agent'') and invested in short-term interest bearing or discount debt obligations issued or guaranteed by the Government of Canada or a province, or one or more of the five largest Canadian chartered banks, provided that in all cases such obligation is rated at least R1 (middle) by DBRS Limited or an equivalent rating from an equivalent rating service, pending receipt by the Corporation of all regulatory and government approvals required to finalize the acquisition (the ''Acquisition'') by the Corporation of all of the issued and outstanding shares of Terasen Inc. (''Terasen''), a wholly owned subsidiary of Kinder Morgan, Inc. (''Kinder Morgan''), including that of the British Columbia Utilities Commission (the ''BCUC''), and fulfillment or waiver of all other outstanding conditions precedent to closing the Acquisition as itemized in the Acquisition Agreement (as defined below) (collectively, the ''Release Conditions''). If the Release Conditions are satisfied prior to 5:00 p.m. (Toronto time) on November 30, 2007, the Corporation will forthwith execute and deliver a notice of satisfaction and will issue and deliver to the Escrow Agent one Common Share for each Subscription Receipt then outstanding (subject to any applicable adjustment). The Common Shares will be available for delivery commencing on the second business day after the delivery of such notice. The holders of Subscription Receipts will receive, without payment of any additional consideration, one Common

	Share for each Subscription Receipt held plus an amount equal to the dividends declared on the Common Shares by the Corporation, if any, for which record dates have occurred during the period from the Closing Date (as defined below) to the date of issuance of the Common Shares in respect of the Subscription Receipts. Forthwith upon the Release Conditions being satisfied and the required notice being delivered to the Escrow Agent, the Escrowed Funds, together with interest earned and income generated thereon, will be released to Fortis. In the event that the Release Conditions are not satisfied prior to 5:00 p.m. (Toronto time) on November 30, 2007, or if the Acquisition Agreement is terminated prior to such time (in either case, the ''Termination Time''), holders of Subscription Receipts shall, commencing on the second business day following the Termination Time, be entitled to receive from the Escrow Agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned or income generated on such amount. See ''Details of the Offering''.
Use of Proceeds:	The proceeds of the Offering, after deducting the fee payable to CIBC World Markets Inc. (''CIBCWM''), Scotia Capital Inc. (''Scotia Capital''), TD Securities Inc. (''TD Securities''), BMO Nesbitt Burns Inc. (''BMO Nesbitt Burns''), RBC Dominion Securities Inc. (''RBCDS''), National Bank Financial Inc. (''NB Financial''), Canaccord Capital Corporation, Beacon Securities Limited and HSBC Securities (Canada) Inc. (''HSBC Securities'') (collectively, the ''Underwriters'') and expenses of the Offering, which are estimated to be $1,250,000, and assuming no exercise of the Over-Allotment Option, together with funds to be advanced under acquisition financing arranged by the Corporation, will be used to finance the cash portion of the consideration payable for the Acquisition. If the Over-Allotment Option is exercised in full, the estimated proceeds of the Offering will be $1,103,854,000 (after deducting the fee payable to the Underwriters and expenses of the Offering). The gross proceeds from the sale of the Subscription Receipts will be held in escrow pending the satisfaction of the Release Conditions, which is expected to occur in mid-2007. See ''Financing of the Acquisition'', ''Details of the Offering'' and ''Use of Proceeds''.
Subscription Receipts:	Each Subscription Receipt entitles the holder thereof to receive, without payment of additional consideration and upon satisfaction of the Release Conditions, one Common Share, plus an amount equal to the dividends declared on the Common Shares by the Corporation, if any, for which record dates have occurred during the period from the Closing Date to the date of issuance of the Common Shares in respect of the Subscription Receipts. If the Release Conditions are not met prior to the Termination Time, the Corporation will repay to holders of Subscription Receipts an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned or income generated on such amount. See ''Details of the Offering''.
Risk Factors:	An investment in the Subscription Receipts and the Common Shares issuable upon exchange thereof involves certain risks which should be carefully considered by prospective investors, including: regulation, forecasting accuracy, asset maintenance, operational risks, weather and other natural disasters, the supply and prices of natural gas, seasonality, risks relating to Terasen Gas (Vancouver Island) Inc., obtaining and maintaining government permits, impact of changes in economic

conditions, availability of capital resources and credit ratings, exposure to interest rate changes, counterparty credit risk, potential undisclosed liabilities associated with the Acquisition, ability to maintain satisfactory labour relations, matters relating to insurance, environmental matters, First Nations' Lands, results of operations and financing risks, management of expanding operations, the ability to realize benefits from the Acquisition, the Subscription Receipt structure and the lack of an existing market for the Subscription Receipts. See ''Risk Factors''.

The Acquisition

Overview

On February 26, 2007, Fortis entered into an agreement (the ''Acquisition Agreement'') with 3211953 Nova Scotia Company and Kinder Morgan for the purchase of all of the issued and outstanding shares of Terasen for aggregate consideration of $3.7 billion, including the assumption of approximately $2.3 billion of consolidated indebtedness of Terasen. Terasen is a holding company headquartered in Vancouver, British Columbia, operating two principal lines of business: natural gas distribution and petroleum transportation. Prior to the closing of the Acquisition, Kinder Morgan will cause Terasen to divest itself of its petroleum transportation operations, leaving only the natural gas distribution business operated by Terasen Gas (as defined below). As part of such divestiture, on March 5, 2007, Kinder Morgan announced that it had agreed to sell the Corridor pipeline system, which is owned by Terasen and serves the Athabasca oil sands, to Inter Pipeline Fund.

The closing of the Acquisition is subject to receipt of required regulatory and other approvals, including that of the BCUC, and the satisfaction of certain closing conditions. The closing of the Acquisition is expected to occur in mid-2007. See ''Acquisition Agreement''.

Based on financial information as at September 30, 2006, following the Acquisition, Fortis' total assets will increase by approximately 94% to $8.9 billion. Following the Acquisition, Fortis' regulated rate base assets will increase to approximately $6.0 billion, of which approximately 93% will be located in Canada.

Kinder Morgan

Kinder Morgan is one of the largest energy transportation, storage and distribution companies in North America. It owns an interest in or operates approximately 65,000 kilometers of pipelines that transport primarily natural gas, crude oil, petroleum products and carbon dioxide, and serves more than 1.1 million natural gas distribution customers in British Columbia, Colorado, Nebraska and Wyoming. Kinder Morgan owns the general partner interest of Kinder Morgan Energy Partners, L.P., one of the largest publicly traded pipeline limited partnerships in the United States.

On November 30, 2005, Kinder Morgan completed the acquisition of Terasen (formerly, BC Gas Inc.). On May 19, 2006, Terasen completed the disposition of its water, wastewater and utility services business carried on by Terasen Water and Utility Services Inc. to a consortium led by CAI Capital Management Co.

On August 14, 2006, Kinder Morgan announced that it was selling its natural gas retail distribution operations serving customers in Colorado, Nebraska, Wyoming and Hermosillo, Mexico, to GE Energy Financial Services. On December 19, 2006, management of Kinder Morgan received shareholder approval of a US$22 billion leveraged management buyout offer led by Richard Kinder, Chairman and Chief Executive Officer, Kinder Morgan. The completion of this buyout is pending.

Terasen Gas

The natural gas distribution business of Terasen is carried on by Terasen Gas Inc. (''TGI''), Terasen Gas (Vancouver Island) Inc. (''TGVI'') and Terasen Gas (Whistler) Inc. (''TGWI''). Terasen also owns a 30% interest in

CustomerWorks Limited Partnership (''CWP''). CWP is a non-regulated shared services business in partnership with Enbridge Inc. that provides customer service contact, meter reading, billing, support and credit and collection services primarily to Terasen Gas (as defined below) and Enbridge Gas Distribution Inc. CWP outsources these services to a company owned and operated by Accenture Inc. In this Prospectus, TGI, TGVI, TGWI and CWP are collectively referred to as ''Terasen Gas''.

Terasen Gas is the principal gas distribution utility in British Columbia, serving the populous lower mainland, Vancouver Island and the southern interior of the province. With approximately 900,000 customers in 125 communities, Terasen Gas provides service to over 95% of the gas customers in British Columbia. Terasen Gas owns and operates approximately 44,100 kilometers of natural gas distribution pipelines and approximately 4,300 kilometers of natural gas transmission pipelines. As of September 30, 2006, Terasen Gas had an aggregate of $3.6 billion of assets, an aggregate rate base of almost $3.0 billion and approximately 1,200 employees.

Acquisition Rationale

The business operated by Terasen Gas is attractive to Fortis for the following reasons: (i) Terasen Gas will significantly increase the earnings of Fortis from regulated utilities and be immediately accretive to earnings per share; (ii) the regulated gas distribution business of Terasen Gas complements the regulated electric distribution business of Fortis; and (iii) the service territory of Terasen Gas is experiencing strong economic growth and includes substantially all of the service territory of FortisBC Inc.

Fortis believes that the principal benefits of the Acquisition are as follows:

(a) the purchase price represents approximately 1.2 times the approved rate base of Terasen Gas for 2007 and the Acquisition is expected to be immediately accretive to earnings per share;

(b) the Acquisition will increase the regulated rate base assets and utility earnings of Fortis. Similar to the electric distribution utilities of Fortis, Terasen Gas operates under principally cost-of-service regulation under which an appropriate return on capital is recovered in addition to prudently incurred operating and commodity costs;

(c) Terasen Gas has an attractive gas distribution franchise with a well-diversified, mature, principally residential, customer base. The Acquisition is expected to improve the risk profile of Fortis by providing it with a more economically diverse portfolio of assets;

(d) following the Acquisition, Fortis will be the largest investor-owned utility in gas and electric distribution in Canada with regulated electricity distribution utilities in five Canadian provinces and three Caribbean countries and regulated gas distribution utilities in British Columbia. Following the Acquisition, a large proportion of the business of Fortis will serve the high-growth economies of western Canada; and

(e) Fortis believes the regulated gas distribution business of Terasen Gas is complementary to the Corporation's proven core competencies in managing regulated electric distribution utilities. The Acquisition affords Fortis management an opportunity to deploy its regulatory, operating and financial management expertise to additional Canadian regulated utilities.

See ''Risk Factors — Realization of Acquisition Benefits'' and ''Special Note Regarding Forward-Looking Statements''.

Utility Management Approach of Fortis

Fortis' approach to utility management is based on creating value for customers that ultimately translates into long-term value for shareholders. Fortis structures its operations as separate operating companies in each jurisdiction. Focused local management teams have the benefit of access to utility management experience and expertise of Fortis. The senior management team of Terasen Gas, which Fortis expects to retain, will add valuable operational expertise in natural gas distribution to existing expertise in the electric distribution operations of Fortis. This approach allows local managers to build relationships with, and be responsive to, both customers and regulators. Fortis recognizes that regulation is a key aspect of its core business and has developed a disciplined, cost-conscious asset investment and operating philosophy which is responsive to regulation.

The management of Fortis has substantial experience in integrating newly acquired enterprises into the Fortis Group. In 2004, Fortis acquired all of the issued and outstanding shares of FortisBC Inc. (formerly, Aquila Networks Canada (British Columbia) Ltd.) and FortisAlberta Inc. (formerly, Aquila Networks Canada (Alberta) Ltd.), and has successfully integrated these utilities into the Fortis Group.

FORTIS

Fortis Inc. (''Fortis'' or the ''Corporation'') was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977. The Corporation was continued under the *Corporations Act* (Newfoundland) on August 28, 1987 and on October 12, 1987 the Corporation amended its articles to change its name to ''Fortis Inc.'' The address of the head office and principal place of business of the Corporation is The Fortis Building, Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2.

Fortis is principally a diversified, international electric utility holding company that owns subsidiaries engaged in the regulated distribution of electricity. Regulated utility assets comprise approximately 86% of the Corporation's total assets, with the balance comprised primarily of non-regulated electricity generating assets, and commercial real estate and hotel investments owned and operated through its non-utility subsidiary. Fortis is the indirect owner of all of the common shares of FortisAlberta Inc. (''FortisAlberta'') (formerly, Aquila Networks Canada (Alberta) Ltd.) and FortisBC Inc. (''FortisBC'') (formerly, Aquila Networks Canada (British Columbia) Ltd.). FortisAlberta is a regulated electric utility that distributes electricity generated by other market participants in Alberta. FortisBC is a regulated electric utility that generates, transmits and distributes electricity in British Columbia. Fortis also holds all the common shares of Newfoundland Power Inc. (''Newfoundland Power'') and, through its wholly owned subsidiary Fortis Properties Corporation (''Fortis Properties''), holds all the common shares of Maritime Electric Company, Limited (''Maritime Electric''), which are the principal distributors of electricity in Newfoundland and on Prince Edward Island, respectively. As well, through its wholly owned subsidiary FortisOntario Inc. (''FortisOntario'') and its subsidiaries, Canadian Niagara Power Inc. (''CNPI'') and Cornwall Street Railway, Light and Power Company, Limited (''Cornwall Electric''), Fortis distributes electricity to customers primarily in Fort Erie, Port Colborne, Gananoque and Cornwall, Ontario.

The Corporation's regulated electric utility assets in the Caribbean consist of its ownership, through wholly owned subsidiaries, of a 70.1% interest in Belize Electricity Limited (''Belize Electricity''), the primary distributor of electricity in Belize, Central America, and an approximate 54% interest in Caribbean Utilities Company, Ltd. (''Caribbean Utilities''), the sole provider of electricity to the island of Grand Cayman, Cayman Islands. On August 28, 2006, Fortis acquired, through a wholly owned subsidiary, all of the outstanding shares of P.P.C. Limited (''PPC'') and Atlantic Equipment & Power (Turks and Caicos) Ltd. (''Atlantic''), (collectively, ''Fortis Turks and Caicos''), which together generate and distribute electricity to approximately 80% of electricity customers in the Turks and Caicos Islands.

The Corporation's non-regulated electricity generation operations consist of its 100% interest in each of Belize Electric Company Limited (''BECOL''), FortisUS Energy Corporation (''FortisUS Energy''), and FortisOntario, as well as non-regulated electricity generation assets owned by FortisBC and Fortis Properties.

Fortis Properties is the direct owner of a 51% interest in the Exploits River Hydro Partnership (the ''Exploits Partnership''). The Exploits Partnership was established with Abitibi-Consolidated Company of Canada (''Abitibi-Consolidated''), which holds the remaining 49% interest, to develop additional capacity at Abitibi-Consolidated's hydroelectric plant at Grand Falls-Windsor and redevelop the forestry company's hydroelectric plant at Bishop's Falls, both in Newfoundland and Labrador. Fortis Properties' assets also include six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 megawatts (''MW'').

BECOL owns and operates both the 25-MW Mollejon and 7-MW Chalillo hydroelectric facilities, both of which are located on the Macal River in Belize. Through FortisUS Energy, a wholly owned subsidiary of Fortis Properties, the Corporation owns and operates four hydroelectric generating stations in upper New York State with a total combined capacity of approximately 23 MW. FortisOntario includes 75 MW of water right entitlement associated with the Rankine Generating Station at Niagara Falls and the operation of a 5-MW gas-fired cogeneration plant that provides district heating to 17 commercial customers in Cornwall. The Rankine Generating Station assets have been written down following the lay-up of the Station as a result of the implementation of a water and power exchange agreement (the ''Niagara Exchange Agreement'') with Ontario Power Generation Inc. (''OPGI''). The Niagara Exchange Agreement assigns FortisOntario's water rights on the Niagara River to OPGI and facilitates the irrevocable exchange of 75 MW of wholesale electric power supply to FortisOntario from OPGI until April 30, 2009 in exchange for FortisOntario's agreement not to seek renewal of the water entitlement at that time. The non-regulated electricity generation operations of FortisBC consist of the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia.

Through its wholly owned subsidiary, Fortis Properties, the Corporation owns and operates hotels in seven provinces in Canada and commercial real estate in Atlantic Canada. Its holdings include 18 hotels with more than 3,200 rooms and approximately 2.7 million square feet of commercial real estate.

Regulated Utilities — Canadian

FortisAlberta

On May 31, 2004, Fortis, through an indirect wholly owned subsidiary, acquired all of the issued and outstanding shares of FortisAlberta. FortisAlberta distributes electricity to approximately 430,000 customers using approximately 104,000 kilometers of power lines and met a peak demand of 2,584 MW in 2006. FortisAlberta's business is the ownership and operation of regulated electricity distribution facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers in southern and central Alberta. FortisAlberta is not involved in the generation, transmission or direct sale of electricity.

FortisBC

On May 31, 2004, Fortis, through an indirect wholly owned subsidiary, acquired all of the issued and outstanding shares of FortisBC. FortisBC is an integrated regulated electric utility that owns a network of generation, transmission and distribution assets located in the southern interior of British Columbia. FortisBC serves a diverse mix of more than 152,000 customers, with residential customers representing the largest customer segment, and met a peak demand of 718 MW in 2006. FortisBC owns four regulated hydroelectric generating plants with an aggregate capacity of 235 MW that provide approximately 45% of the Corporation's energy and 30% of its capacity needs. FortisBC's remaining electricity supply is acquired through long-term power purchase contracts and short-term market purchases. FortisBC includes non-regulated operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generation facility owned by Teck Cominco Metals Ltd., the 149-MW Brilliant Hydroelectric Plant and the 185-MW Arrow Lakes Hydroelectric Plant owned by Columbia Power Corporation and Columbia Basin Trust, respectively, and the distribution system owned by the City of Kelowna.

FortisBC's assets include the electric utility formerly owned by Princeton Light and Power Company, Limited (the ''PLP Utility''). The PLP Utility serves approximately 3,500 customers, mainly in Princeton, British Columbia. The PLP Utility was purchased by Fortis through an indirect subsidiary on May 31, 2005 and became part of FortisBC on December 31, 2006 as the result of an internal corporate reorganization.

Newfoundland Power

Fortis holds all of the common shares of Newfoundland Power. Newfoundland Power is an electric utility that operates an integrated generation, transmission and distribution system throughout the island portion of the Province of Newfoundland and Labrador. Newfoundland Power serves approximately 230,000 customers, or approximately 85% of electricity customers in the Province, and met a peak demand of 1,166 MW in 2006. Approximately 90% of the electricity that Newfoundland Power sells to its customers is purchased from Newfoundland and Labrador Hydro Corporation (''Newfoundland Hydro''). Currently, Newfoundland Power has an installed generating capacity of 136 MW, of which 92 MW is hydroelectric generation.

Maritime Electric

Through its subsidiary, Fortis Properties, Fortis owns all of the common shares of Maritime Electric, which is the principal distributor of electricity on Prince Edward Island. Maritime Electric directly supplies approximately 71,000 customers, or approximately 90% of the electricity consumers on the Island, and met a peak demand of 216 MW in 2006. Maritime Electric purchases most of the energy it distributes to its customers from New Brunswick Power Corporation and maintains on-Island generating facilities at Charlottetown and Borden-Carleton with a combined capacity of 150 MW.

FortisOntario

The Corporation's regulated utility investments in Ontario are comprised of CNPI, including the operations of Port Colborne Hydro, and Cornwall Electric, all of which are owned through FortisOntario. In total, FortisOntario's distribution operations serve approximately 52,000 customers in the Fort Erie, Port Colborne, Cornwall and Gananoque areas of Ontario and met a combined peak demand of 233 MW in 2006. CNPI owns international transmission facilities at Fort Erie as well as a 10% interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies formed in 2000 that, together, serve more than 27,000 customers.

Regulated Utilities — Caribbean

Belize Electricity

Fortis, through wholly owned subsidiaries, holds a 70.1% interest in Belize Electricity. Belize Electricity is the primary distributor of electricity in the Central American country of Belize. Belize Electricity directly supplies approximately 71,000 customers in Belize and met a peak demand of 67 MW in 2006.

Caribbean Utilities

Fortis, through a wholly owned subsidiary, holds an approximate 54% interest in Caribbean Utilities, the only public electric utility on Grand Cayman, Cayman Islands. Caribbean Utilities has the exclusive right to generate, distribute, transmit and supply electricity to the island of Grand Cayman, Cayman Islands, pursuant to a 25-year licence. The current licence remains in effect until January 2011 or until replaced by a new licence by the mutual consent of Caribbean Utilities and the Government of the Cayman Islands. Negotiations regarding the renewal of the licence are ongoing. Caribbean Utilities currently serves more than 22,000 customers, owns 120 MW of installed generating capacity, and met a peak demand of 87 MW in 2006.

The Class A Ordinary Shares of Caribbean Utilities are listed for trading on the Toronto Stock Exchange (the ''TSX'') under the symbol CUP.U. The Corporation's investment in Caribbean Utilities resulted from a series of transactions from March 2000 through November 2006, as a result of which Fortis beneficially owns 13,565,511, or approximately 54%, of the outstanding Class A Ordinary Shares. See ''Recent Developments''.

Fortis Turks and Caicos

The Corporation owns, through a wholly owned subsidiary, all of the outstanding shares of Fortis Turks and Caicos which serves approximately 7,700 customers, or approximately 80% of electricity customers, in the Turks and Caicos Islands. Fortis Turks and Caicos is the principal distributor of electricity in Providenciales, North Caicos and Middle Caicos pursuant to a 50-year licence that expires in 2037 and is the principal distributor of electricity in South Caicos pursuant to a 50-year licence that expires in 2036. Fortis Turks and Caicos has installed generating capacity of approximately 35 MW and met a peak demand of 25 MW in 2006.

Fortis Turks and Caicos is regulated under a traditional rate of return on rate base approach, with a fixed rate of return of 17.5% on a defined asset base of approximately US$50 million.

Non-Regulated — Fortis Generation

Ontario

Non-regulated generation assets in Ontario include the operations of FortisOntario and Fortis Properties. Fortis Properties' operations in Ontario consist of six small hydroelectric generating stations with a combined capacity of approximately 8 MW. FortisOntario's assets include 75 MW of water entitlement associated with the Rankine Generating Station at Niagara Falls and the operation of a 5-MW gas-fired cogeneration plant that provides district heating to 17 commercial customers in Cornwall. The Rankine Generating Station assets have been written down following the lay-up of the Station as a result of the implementation of the Niagara Exchange Agreement. The Niagara Exchange Agreement assigns FortisOntario's water rights on the Niagara River to OPGI and facilitates the irrevocable exchange of 75 MW of wholesale electric power supply to FortisOntario from OPGI until April 30, 2009 in exchange for FortisOntario's agreement not to seek renewal of the water entitlement at that time.

Belize

Non-regulated generation operations in Belize are conducted through the Corporation's wholly owned indirect subsidiary, BECOL, under a franchise agreement with the Government of Belize. BECOL owns and operates the 25-MW Mollejon hydroelectric facility and the 7-MW Chalillo hydroelectric facility, which was placed in service on November 15, 2005. Both facilities are located on the Macal River in Belize. These generating plants have the capability of delivering average annual energy production of approximately 160 gigawatt hours (''GWh''). BECOL sells its entire output to Belize Electricity under a 50-year power purchase agreement expiring in 2055.

Central Newfoundland

Non-regulated generation operations in central Newfoundland are conducted through the Corporation's indirect 51% interest in the Exploits Partnership. The Exploits Partnership is a partnership with Abitibi-Consolidated that constructed, installed and operates additional capacity at Abitibi-Consolidated's hydroelectric plant at Grand Falls-Windsor and redeveloped the forestry company's hydroelectric plant at Bishop Falls, both in Newfoundland and Labrador. The 51% interest in the partnership is owned by Fortis Properties. Abitibi-Consolidated continues to utilize the historical annual generation of approximately 450 GWh while the additional energy produced from the new facilities, approximately 140 GWh, is sold to Newfoundland Hydro under a 30-year take-or-pay power purchase agreement expiring in 2033, which is exempt from regulation.

Upper New York State

Non-regulated generation operations in upper New York State are conducted through the Corporation's wholly owned indirect subsidiary FortisUS Energy, which became a direct subsidiary of Fortis Properties on January 1, 2005 by way of a transfer from its subsidiary, Maritime Electric. Generating operations in upper New York State include the operations of four hydroelectric generating stations with a combined generating capacity of approximately 23 MW operating under licences from the United States Federal Energy Regulatory Commission.

British Columbia

Non-regulated generation operations in British Columbia were acquired as part of FortisBC in May 2004. Generating assets in British Columbia consist of the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to British Columbia Hydro & Power Authority (''BC Hydro'') under a power purchase agreement expiring in 2013.

Non-Regulated — Fortis Properties

Fortis has owned all of the issued and outstanding shares of Fortis Properties since its inception in 1989. In addition to its non-regulated generation operations, Fortis Properties owns and operates hotels in seven provinces in Canada and commercial real estate in Atlantic Canada. Its holdings include 18 hotels with more than 3,200 rooms and approximately 2.7 million square feet of commercial real estate. On November 1, 2006, Fortis Properties completed the purchase of four hotels located in Alberta and British Columbia from Lodge Motel (Kelowna) Ltd. for approximately $52 million. See ''Recent Developments''.

RECENT DEVELOPMENTS

Acquisition of Hotels in Western Canada

On November 1, 2006, Fortis Properties completed the purchase of four hotels located in Alberta and British Columbia from Lodge Motel (Kelowna) Ltd. for approximately $52 million. The purchased hotels were: the Holiday Inn Express and Suites and the Best Western, both in Medicine Hat, Alberta; the Ramada Hotel and Suites, in Lethbridge, Alberta; and the Holiday Inn Express, in Kelowna, British Columbia. Through the purchase, Fortis Properties' hospitality operations were expanded by 454 rooms.

Acquisition of Additional Shares of Caribbean Utilities

On November 7, 2006, Fortis acquired an aggregate of 4,113,116, or approximately 16%, of the outstanding Class A Ordinary Shares of Caribbean Utilities from International Power and four other vendors affiliated with International Power for US$11.89 per share under a private agreement. Pursuant to this purchase, Fortis acquired control of Caribbean Utilities raising its beneficial ownership to 13,565,511, or approximately 54%, of the outstanding Class A Ordinary Shares. As a result of acquiring control of Caribbean Utilities, Fortis now consolidates the financial results of Caribbean Utilities into the financial statements of Fortis. Immediately prior to November 1, 2006, Fortis accounted for its investment in Caribbean Utilities on an equity basis, pursuant to which only its *pro rata* share of earnings of Caribbean Utilities was recorded in the consolidated statements of earnings of Fortis.

Private Placement of Convertible Debentures

On November 7, 2006, Fortis issued, by way of private placement, US$40 million aggregate principal amount of unsecured subordinated convertible debentures (the ''Debentures''). The Debentures bear interest at an annual rate of 5.5% and mature on November 7, 2016. The Debentures may be redeemed by Fortis at par at any time on or after November 7, 2011 and are convertible into common shares of Fortis (''Common Shares'') at the option of the holder at any time prior to their maturity, at US$29.11 per share.

Regulatory Matters

During the fourth quarter of 2006, the allowed regulated rate of return on common equity (''ROE'') for each of FortisBC, FortisAlberta and Newfoundland Power was reset in accordance with an automatic adjustment formula by each utility's respective regulator. The allowed ROEs for FortisAlberta, FortisBC and Newfoundland Power were reduced from 8.93%, 9.20% and 9.24% to 8.51%, 8.77% and 8.60%, respectively, effective January 1, 2007.

On December 5, 2006, Newfoundland Power received approval of its 2007 Amortization and Cost Deferral Accounting application from the Newfoundland and Labrador Board of Commissioners of Public Utilities. The order provided for a portion of the 2005 unbilled revenue balance amortization to offset increased taxes in 2007 and the deferral of increased amortization and replacement energy expenses in 2007. Recovery of these amounts will be addressed in Newfoundland Power's next general rate proceeding.

During the fourth quarter of 2006, the British Columbia Utilities Commission (the ''BCUC'') approved FortisBC's 2007 and 2008 capital plans of $135.8 million (before customer contributions of $7.2 million) and $119.6 million (before customer contributions of $8.0 million), respectively, subject to further approval processes for certain projects. Earlier in 2006, a Negotiated Settlement Agreement, approved by the Alberta Energy and Utilities Board, dealing with FortisAlberta's 2006/2007 Distribution Access Tariff Application included a 2007 capital expenditure program of $201 million (before customer contributions of $24 million and including $10 million in contributions to the Alberta Electric System Operator (''AESO'') for investment in transmission facilities). During the fourth quarter, FortisAlberta's 2007 capital plan was increased to approximately $273 million (before customer contributions of $33 million and including $17 million in contributions to the AESO for investment in transmission facilities), primarily driven by customer growth. The increase in the 2007 capital expenditure program will be included as part of FortisAlberta's 2008 rate application.

Issuance of Debentures by FortisAlberta

On January 3, 2007, FortisAlberta issued $110 million aggregate principal amount of senior unsecured debentures bearing interest at a rate of 4.99% per annum, payable semi-annually, due January 2047.

Issuance of Common Shares by Fortis

On January 18, 2007, Fortis completed the public offering of 5,170,000 Common Shares at a price of $29.00 per share for gross proceeds of $149,930,000.

Second Quarter Dividend

On February 8, 2007, Fortis announced that its Board of Directors had declared a second quarter dividend of $0.21 per Common Share payable on June 1, 2007 to holders of record on May 4, 2007. This dividend represents an increase of 10.5% in the quarterly Common Share dividend of the Corporation, which is the second increase in twelve months. Fortis has increased its annual dividend paid for 34 consecutive years.

2006 Results of Operations

On February 8, 2007, Fortis issued a media release announcing its unaudited results of operations for the year ended December 31, 2006 and the Corporation's unaudited interim consolidated financial statements and related Management Discussion and Analysis of financial condition and results of operations for the three- and twelve-month periods ended December 31, 2006.

Net earnings applicable to Common Shares in 2006 were $147.2 million, 7.4% higher than net earnings of $137.1 million in 2005. Earnings per Common Share were $1.42 compared to $1.35 in 2005. Earnings in 2005 included a $7.9 million after-tax gain resulting from the settlement of contractual matters between FortisOntario and OPGI (the ''Ontario Settlement''). Growth in annual earnings was primarily driven by the performance of FortisAlberta and FortisBC, hydroelectric generation in Belize, Fortis Properties, Belize Electricity and contributions from recently acquired Fortis Turks and Caicos.

Net earnings applicable to Common Shares for the fourth quarter of 2006 were $33.9 million, or $0.33 per Common Share, compared to $22.3 million, or $0.22 per Common Share in the fourth quarter of 2005. The increase in fourth quarter earnings was driven by earnings growth at FortisAlberta, the contribution from Fortis Turks and Caicos and a change in revenue recognition policy by Newfoundland Power in 2006.

Fortis' Canadian Regulated Utilities contributed $112.7 million to earnings in 2006, $7.9 million higher than earnings of $104.8 million in the previous year. The increase was primarily driven by earnings derived from the significant investments in electrical infrastructure made by FortisAlberta and FortisBC and lower corporate income taxes at FortisAlberta.

In 2006, FortisAlberta and FortisBC continued to maintain, enhance and expand their electricity systems to accommodate new customers and to improve system reliability and invested approximately $354 million in aggregate, before customer contributions, in capital projects, up 26% from 2005. The rate bases of FortisAlberta and FortisBC have increased approximately 29% and 36%, respectively, since the utilities were acquired in May 2004.

Fortis' Caribbean Regulated Utilities, comprised of Fortis Turks and Caicos, Belize Electricity and Caribbean Utilities, contributed earnings of $23.6 million in 2006, 21.6% higher than earnings of $19.4 million in 2005. Earnings growth was primarily attributable to $3.5 million of contribution from Fortis Turks and Caicos and improved earnings at Belize Electricity due to lower finance charges, growth in electricity sales and an overall 11% increase in electricity rates, effective July 1, 2005.

In 2006, Fortis Non-regulated Generation operations contributed earnings of $26.7 million compared to $29.6 million in the previous year. Excluding the $7.9 million after-tax Ontario Settlement gain in 2005, earnings were $5.0 million higher year over year. Improved performance in Belize driven by increased hydroelectric production and lower finance charges was partially offset by the impact of lower average wholesale energy prices in Ontario. Hydroelectric production in Belize was 178 GWh, more than two-and-a-half times the level of production in 2005 due to the first full year of operations for the Chalillo hydroelectric generation plant and storage facility. Energy sales in Ontario, which on an annual basis remained relatively consistent at approximately 700 GWh, were at an average annual wholesale energy price per megawatt hour of $46.38 compared to $68.49 in 2005.

Fortis Properties contributed earnings of $18.7 million in 2006, 32.6% higher than earnings of $14.1 million in 2005. The increase in earnings was largely driven by a $1.6 million after-tax gain on the sale of the Days Inn Sydney hotel, reduced corporate income taxes and growth at hotel operations in western Canada.

THE ACQUISITION

Overview

On February 26, 2007, Fortis entered into an agreement (the ''Acquisition Agreement'') with 3211953 Nova Scotia Company and Kinder Morgan Inc. (''Kinder Morgan'') for the purchase (the ''Acquisition'') of all of the issued and outstanding shares of Terasen Inc. (''Terasen'') for aggregate consideration of $3.7 billion, including the assumption of approximately $2.3 billion of consolidated indebtedness of Terasen. Terasen is a holding company headquartered in Vancouver, British Columbia, operating two principal lines of business: natural gas distribution and petroleum transportation. Prior to the closing of the Acquisition, Kinder Morgan will cause Terasen to divest itself of its petroleum transportation operations. As part of such divestiture, on March 5, 2007, Kinder Morgan announced that it had agreed to sell the Corridor pipeline system, which is owned by Terasen and serves the Athabasca oil sands, to Inter Pipeline Fund.

The closing of the Acquisition is subject to receipt of required regulatory and other approvals, including that of the BCUC, and the satisfaction of certain closing conditions. The closing of the Acquisition is expected to occur in mid-2007. See ''Acquisition Agreement''.

Under the Acquisition Agreement, Kinder Morgan or the Corporation may elect to terminate the Acquisition Agreement if the Acquisition is not completed prior to November 30, 2007. The Corporation intends to finance the cash portion of the purchase price for the Acquisition from the net proceeds of this offering (the ''Offering'') and funds to be advanced under acquisition financing arranged by the Corporation for this purpose. See ''Financing of the Acquisition'', ''Use of Proceeds'' and ''Acquisition Agreement''.

Based on financial information as at September 30, 2006, following the Acquisition, Fortis' total assets will increase by approximately 94% to $8.9 billion. Following the Acquisition, Fortis' regulated rate base assets will increase to approximately $6.0 billion, of which approximately 93% will be located in Canada.

Kinder Morgan

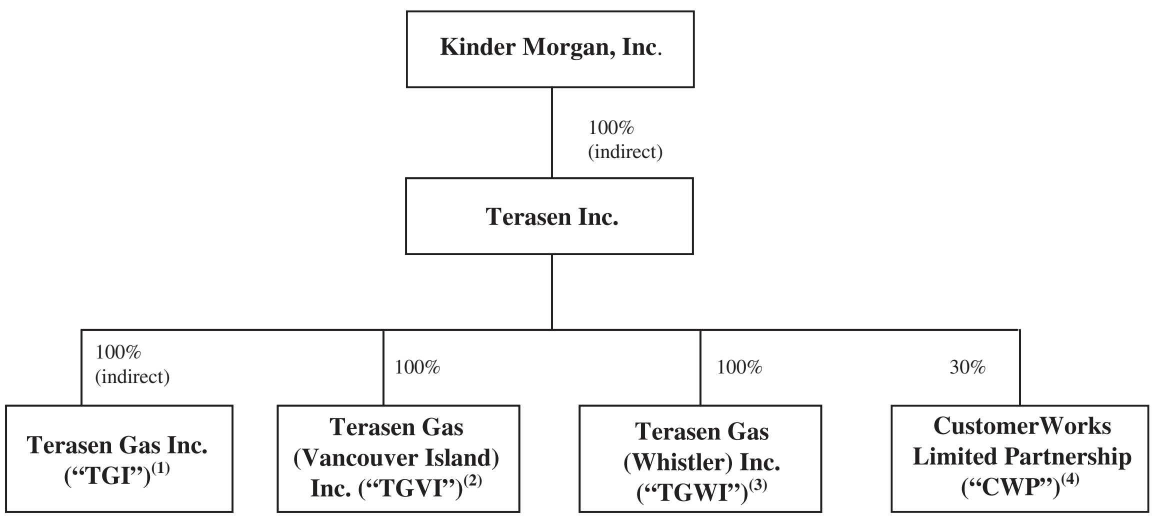
Kinder Morgan is one of the largest energy transportation, storage and distribution companies in North America. It owns an interest in or operates approximately 65,000 kilometers of pipelines that transport primarily natural gas, crude oil, petroleum products and carbon dioxide, and serves more than 1.1 million natural gas distribution customers in British Columbia, Colorado, Nebraska and Wyoming. Kinder Morgan owns the general partner interest of Kinder Morgan Energy Partners, L.P., one of the largest publicly traded pipeline limited partnerships in the United States.

On November 30, 2005, Kinder Morgan completed the acquisition of Terasen (formerly, BC Gas Inc.). On May 19, 2006, Terasen completed the disposition of its water, wastewater and utility services business carried on by Terasen Water and Utility Services Inc. to a consortium led by CAI Capital Management Co.

On August 14, 2006, Kinder Morgan announced that it was selling its natural gas retail distribution operations serving customers in Colorado, Nebraska, Wyoming and Hermosillo, Mexico, to GE Energy Financial Services. On December 19, 2006, management of Kinder Morgan received shareholder approval of a US$22 billion leveraged management buyout offer led by Richard Kinder, Chairman and Chief Executive Officer, Kinder Morgan. The completion of this buyout is pending.

Prior to the closing of the Acquisition, Kinder Morgan will cause Terasen to divest itself of its petroleum transportation operations (the ''Pre-Closing Reorganization''), leaving only the natural gas distribution business operated by Terasen Gas (as defined below). As part of the Pre-Closing Reorganization, on March 5, 2007, Kinder Morgan announced that it had agreed to sell the Corridor pipeline system, which is owned by Terasen and serves the Athabasca oil sands, to Inter Pipeline Fund. Under the Acquisition Agreement, Fortis will be indemnified with respect to claims relating to the Pre-Closing Reorganization. See ''Acquisition Agreement — Indemnities''.

The chart below sets out the material subsidiaries of Terasen following the Pre-Closing Reorganization.



(1) Terasen Gas Inc. provides gas distribution services to approximately 734,000 residential and 82,000 commercial and industrial customers in a service area extending from Vancouver to the Fraser Valley and the interior of British Columbia.

(2) Terasen Gas (Vancouver Island) Inc. owns a combined distribution and transmission system and serves approximately 85,000 residential, commercial and industrial customers along the Sunshine Coast and in various communities on Vancouver Island including Victoria and surrounding areas.

(3) Terasen Gas (Whistler) Inc. owns and operates the propane distribution system in the Whistler area of British Columbia and provides service to approximately 2,350 residential and commercial customers.

(4) CustomerWorks Limited Partnership is a non-regulated shared services business in partnership with Enbridge Inc. that provides customer service contact, meter reading, billing, credit, support and collection services primarily to the natural gas distribution operations of Terasen and Enbridge Gas Inc.

Terasen Gas

The natural gas distribution business of Terasen is carried on by Terasen Gas Inc. (''TGI''), Terasen Gas (Vancouver Island) Inc. (''TGVI'') and Terasen Gas (Whistler) Inc. (''TGWI''). Terasen also owns a 30% interest in CustomerWorks Limited Partnership (''CWP''). CWP is a non-regulated shared services business in partnership with Enbridge Inc. (''Enbridge'') that provides customer service contact, meter reading, billing, support and credit and collection services primarily to Terasen Gas (as defined below) and Enbridge Gas Distribution Inc. (''Enbridge Gas''). CWP outsources these services to a company owned and operated by Accenture Inc. (''Accenture''). In this Prospectus, TGI, TGVI, TGWI and CWP are collectively referred to as ''Terasen Gas''.

Terasen Gas is the principal gas distribution utility in British Columbia, serving the populous lower mainland, Vancouver Island and the southern interior of the province. With approximately 900,000 customers in 125 communities, Terasen Gas provides service to over 95% of the gas customers in British Columbia. Terasen Gas owns and operates approximately 44,100 kilometers of natural gas distribution pipelines and approximately 4,300 kilometers of natural gas transmission pipelines. As of September 30, 2006, Terasen Gas had an aggregate of $3.6 billion of assets, an aggregate rate base of almost $3.0 billion and approximately 1,200 employees.

Acquisition Rationale

The business operated by Terasen Gas is attractive to Fortis for the following reasons: (i) Terasen Gas will significantly increase the earnings of Fortis from regulated utilities and be immediately accretive to earnings per share; (ii) the regulated gas distribution business of Terasen Gas complements the regulated electric distribution business of Fortis; and (iii) the service territory of Terasen Gas is experiencing strong economic growth and includes substantially all of the service territory of FortisBC.

Fortis believes that the principal benefits of the Acquisition are as follows:

(a) the purchase price represents approximately 1.2 times the approved rate base of Terasen Gas for 2007 and the Acquisition is expected to be immediately accretive to earnings per share;

(b) the Acquisition will increase the regulated rate base assets and utility earnings of Fortis. Similar to the electric distribution utilities of Fortis, Terasen Gas operates under principally cost-of-service regulation under which an appropriate return on capital is recovered in addition to prudently incurred operating and commodity costs;

(c) Terasen Gas has an attractive gas distribution franchise with a well-diversified, mature, principally residential, customer base. The Acquisition is expected to improve the risk profile of Fortis by providing it with a more economically diverse portfolio of assets;

(d) following the Acquisition, Fortis will be the largest investor-owned utility in gas and electric distribution in Canada with regulated electricity distribution utilities in five Canadian provinces and three Caribbean countries and regulated gas distribution utilities in British Columbia. Following the Acquisition, a large proportion of the business of Fortis will serve the high-growth economies of western Canada; and

(e) Fortis believes the regulated gas distribution business of Terasen Gas is complementary to the Corporation's proven core competencies in managing regulated electric distribution utilities. The Acquisition affords Fortis management an opportunity to deploy its regulatory, operating and financial management expertise to additional Canadian regulated utilities.

See ''Risk Factors — Realization of Acquisition Benefits'' and ''Special Note Regarding Forward-Looking Statements''.

Utility Management Approach of Fortis

Fortis' approach to utility management is based on creating value for customers that ultimately translates into long-term value for shareholders. Fortis structures its operations as separate operating companies in each jurisdiction. Focused local management teams have the benefit of access to utility management experience and expertise of Fortis. The senior management team of Terasen Gas, which Fortis expects to retain, will add valuable operational expertise in natural gas distribution to existing expertise in the electric distribution operations of Fortis. This approach allows local managers to build relationships with, and be responsive to, both customers and regulators. Fortis recognizes that regulation is a key aspect of its core business and has developed a disciplined, cost-conscious asset investment and operating philosophy which is responsive to regulation.

The management of Fortis has substantial experience in integrating newly acquired enterprises into the Fortis Group. In 2004, Fortis acquired all of the issued and outstanding shares of FortisBC (formerly, Aquila Networks Canada (British Columbia) Ltd.) and FortisAlberta (formerly, Aquila Networks Canada (Alberta) Ltd.), and has successfully integrated these utilities into the Fortis Group.

THE ACQUIRED BUSINESSES

The description of Terasen Gas contained in the Prospectus is based on publicly available information filed by Terasen, TGI and Kinder Morgan and information provided by Kinder Morgan in connection with the Acquisition Agreement. Fortis, after making its purchase investigations, believes it to be accurate in all material respects.

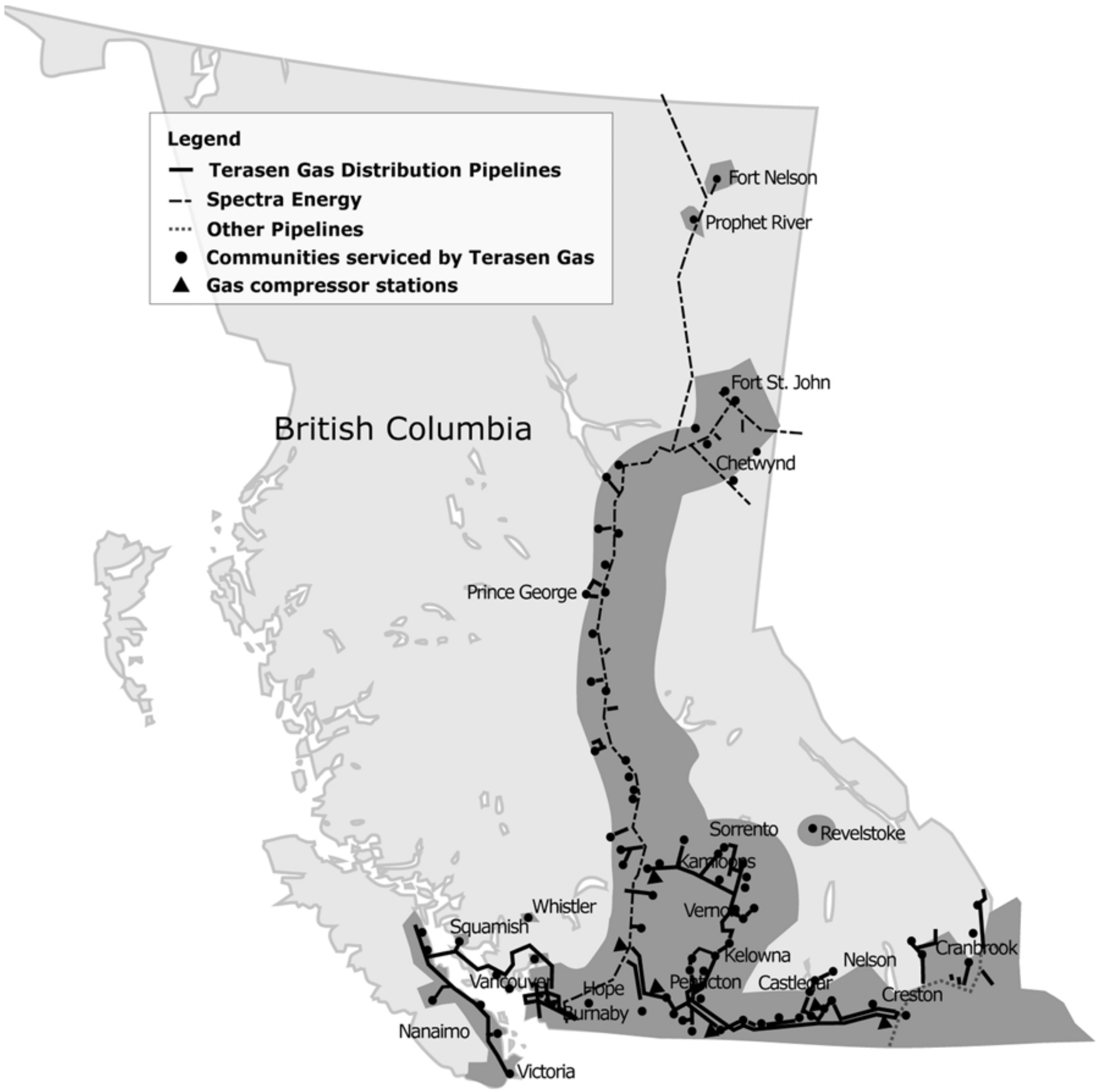
Terasen Inc.

Terasen is a holding company headquartered in Vancouver, British Columbia, operating two principal lines of business: natural gas distribution and petroleum transportation. Prior to the closing of the Acquisition, Kinder Morgan will cause Terasen to divest itself of its petroleum transportation operations. The natural gas distribution business of Terasen is carried on by TGI, TGVI and TGWI. Terasen also owns a 30% interest in CWP, a non-regulated shared services business in partnership with Enbridge that provides customer service contact, meter reading, billing, support and credit and collection services primarily to Terasen Gas and Enbridge Gas. CWP outsources these services to a company owned and operated by Accenture. Terasen has approximately 20 employees principally involved with finance, tax and legal matters.

Terasen was incorporated on August 15, 1985 under the *Company Act* (British Columbia), a predecessor to the *Business Corporations Act* (British Columbia). On April 25, 2003, its name was changed from BC Gas Inc. to Terasen Inc. For further information on Terasen, reference is made to the audited consolidated financial statements of Terasen for the years ended December 31, 2005 and 2004 and related Management Discussion and Analysis of financial condition and results of operations, and the unaudited consolidated financial statements of Terasen for the three- and nine-month periods ended September 30, 2006 and related Management Discussion and Analysis of financial condition and results of operations, which are included in this Prospectus.

Terasen Gas Service Territory

Terasen Gas is one of the largest natural gas distribution businesses in Canada. With approximately 900,000 customers in 125 communities, Terasen Gas provides service to over 95% of the gas customers in British Columbia. Its service area extends from Vancouver to the Fraser Valley, the interior of British Columbia, the area along the Sunshine Coast, as well as Whistler, Squamish and Vancouver Island.



Terasen Gas Inc.

TGI provides service to more than 100 communities with a service territory that has an estimated population of approximately 4,000,000. As at September 30, 2006, TGI and its subsidiaries transported and distributed natural gas to approximately 734,000 residential and 82,000 commercial and industrial customers, representing approximately 87% of the natural gas users in British Columbia. TGI's service area extends from Vancouver to the Fraser Valley and the interior of British Columbia. The transmission and distribution business is carried on under statutes and franchises or operating agreements granting the right to operate in the municipalities or areas served. TGI is regulated by the BCUC. The average rate base of TGI approved by the BCUC for 2007 is approximately $2,474 million.

TGI provides natural gas distribution services to residential, small commercial and industrial heating customers predominantly on a non-contractual basis, whereby the customers are charged based on general services provided. Larger commercial and industrial customers are normally provided with services on a contractual basis.

By early 2006, 16,000 commercial and industrial customers had arranged for some or all of their own gas supply and used TGI's transportation services for delivery. Notwithstanding shifts over time between utility supply and direct purchases, TGI's earnings remain unaffected since TGI's margins remain substantially the same whether or not customers choose to buy natural gas from TGI or arrange their own supply. Customers arranging for their own supply in fact reduce the credit risk to TGI. See ''— Terasen Gas Inc. — Unbundling'' below.

Of TGI's industrial customers, 158 are on interruptible service. The majority of these customers are capable of switching to alternative fuels. Of the various industries that comprise TGI's industrial market, the pulp and paper and wood products industries combined comprise approximately 47% of total system throughput. All other industries individually represent less than 10% of total consumption.

Gas Purchase Agreements

In order to acquire supply resources that ensure reliable natural gas deliveries to its customers, TGI purchases supply from a select list of producers, aggregators, and marketers by adhering to strict standards of counterparty creditworthiness and contract execution/management procedures. TGI contracts for approximately 137 petajoules (''PJ'') of baseload and seasonal supply, of which 120 PJ is delivered off the Spectra Energy Gas Transmission system (the ''Spectra Pipeline System''), and 17 PJ is comprised of Alberta-sourced supply transported into British Columbia via the Alberta and British Columbia systems of TransCanada Pipelines Limited (''TransCanada''). The majority of supply contracts in the current portfolio are one year in length, with the exception of one long-term contract expiring in October 2009. In order to recover its costs, TGI obtains advance BCUC approval of the supply agreements it proposes to enter into.

Peak Shaving Arrangements

TGI incorporates peak shaving and gas storage facilities into its portfolio to (i) manage the load factor of baseload supply contracts throughout the year, (ii) eliminate the risk of supply shortages during a peak throughput day, (iii) reduce the cost of gas during winter months, and (iv) balance daily supply and demand on the distribution system. TGI's peak shaving and storage assets and contracts for 2006 included up to 30 PJ in storage capacity at various locations throughout British Columbia, Alberta and the Pacific Northwest of the United States. These facilities can deliver a maximum daily rate of 600 TJ on a combined basis.

Unbundling

Over the past several years, TGI, the BCUC and a number of interested parties have laid the groundwork for the introduction of natural gas commodity unbundling. As of November 1, 2004, commercial customers of TGI became eligible to sign up to buy their natural gas commodity supply directly from third-party suppliers. TGI continues to provide delivery of the natural gas. Approximately 78,000 commercial customers are eligible to participate in commodity unbundling.

On August 14, 2006, the BCUC released a decision to open a portion of British Columbia's residential natural gas market to competition, allowing homeowners to sign long-term fixed-price contracts for natural gas with companies other than TGI. The BCUC decision was released in response to a proposal from TGI filed with the BCUC on April 18, 2006 and following several weeks of public hearings and submissions from TGI, natural gas marketers and stakeholders. As a result of the BCUC decision, independent marketing companies, known as gas marketers, will be allowed to start offering long-term, fixed-price contracts for natural gas for a period of time ranging from one year to five years, starting in May 2007. TGI will continue delivering the gas to the final consumer, charging for delivery and providing all billing and other services to all customers.

The choice of natural gas suppliers will only be available to TGI's residential customers in the Lower Mainland and the interior of British Columbia. It will not be available on Vancouver Island, the Sunshine Coast, Powell River or Whistler. The opening of a portion of British Columbia's residential natural gas market to competition will not affect TGI's earnings since TGI's margins remain substantially the same whether or not customers choose to buy natural gas from TGI or arrange their own supply.

Transmission Services

TGI serves Greater Vancouver and the Fraser Valley through a transmission and distribution system that connects to the Spectra Pipeline System near Huntingdon, British Columbia. This transmission system also supplies gas to TGVI for delivery to the Sunshine Coast, Vancouver Island and Squamish, British Columbia. In addition, TGI is connected at Huntingdon to Northwest Pipeline to facilitate gas movement both north and south.

In the interior of British Columbia, TGI serves municipalities with numerous connections to the Spectra Pipeline System. Communities in the East Kootenay region of British Columbia are served through connections with the British Columbia system of TransCanada. TGI is connected to TransCanada's British Columbia system through TGI's Southern Crossing Pipeline between Yahk and Oliver. TGI also operates a propane distribution system in Revelstoke, British Columbia.

In addition, TGI provides high-pressure transmission services to customers, such as TGVI, which moves natural gas from the Spectra Pipeline System or the TransCanada system across TGI's system to customers' own facilities.

Transportation tolls on the Spectra Pipeline System and the TransCanada system are regulated by the National Energy Board. TGI pays both fixed and variable charges for use of the pipelines, which are recovered through rates paid by TGI's customers.

Properties

As of September 30, 2006, TGI owned approximately 3,700 kilometers of natural gas transmission pipelines and approximately 41,000 kilometers of natural gas distribution pipelines. In addition to the pipelines, TGI owns properties and equipment utilized for service shops, warehouses, metering, and regulating stations, as well as its main operations center in Surrey, British Columbia.

Title to Properties

TGI's pipelines are constructed for the most part under highways and streets pursuant to permits or orders from the appropriate authorities, franchise or operating agreements entered into with municipalities and rights-of-way held directly or jointly with BC Hydro. Compressor stations and major regulator stations are located on freehold land, rights-of-way owned by TGI or properties shared with BC Hydro.

Franchise and Operating Agreements

TGI currently holds franchise or operating agreements with all of the incorporated municipalities in which it distributes gas in the Greater Vancouver and Fraser Valley service areas, other than Richmond, British Columbia, and with most of the incorporated municipalities in which it distributes gas in the interior of British Columbia. TGI has the right to serve all end users within its franchise area pursuant to these operating agreements. The terms of the franchise agreements range from 10 years to 21 years.

Historically, approximately one quarter of the agreements relating to the interior of British Columbia contained a provision enabling the municipality to purchase the distribution system at the end of the term of the agreement. Some of these agreements have expired and TGI has negotiated or is currently negotiating renewals and extensions of others whereby TGI enters into an arrangement whereby the relevant municipality leases TGI's gas distribution assets within the municipality's boundaries for a term of 35 years for an initial cash payment paid by the municipality to TGI. TGI, in turn, enters into a 17-year operating lease with the municipality whereby TGI operates the gas distribution assets and has the option to terminate the lease of the assets to the municipality at the end of the 17-year term in exchange for a payment to the municipality equal to the unamortized portion of prepaid rent initially paid by the municipality. As at December 31, 2005, TGI had entered into such arrangements having a total value of $153 million.

Capital Program

The 2007 revenue requirements approved by the BCUC for TGI include annual capital expenditures of $129.7 million. Capital expenditures relating to customer growth represent approximately 22% of the annual capital budget forecast, while the remaining amount relates to capital betterments, replacements and life extensions.

Operations

As part of its multi-year Performance-Based Rate (''PBR'') agreement, TGI is required to meet several service quality targets. These target measures include indicators such as emergency response time, speed of answering calls, system integrity, customer satisfaction, meter exchange appointment activity, number of customer complaints to the BCUC and number of prior period adjustments. TGI's operations meet or exceed these target measures.

Environment

In order to minimize impacts from its operations, TGI has developed an Environmental Management System based on a framework, purposes and objectives so as to be compliant with the international standard ISO 14001. TGI's operations meet or exceed legislative standards and environmental protection requirements.

TGI is an active participant in Canada's Voluntary Climate Change Challenge and Registry (''VCR'') and its successor, the Canadian GHG Challenge Registry. For seven consecutive years, TGI has received gold-level reporting status in recognition of its efforts to manage and reduce greenhouse gas emissions. TGI received the VCR Leadership Award in 2001 and 2003, the only company in its sector to have received this award twice. The VCR ranking acknowledges TGI's efforts to develop specific measures and voluntarily set reduction targets.

Employees

TGI has approximately 1,100 employees. Its organized employees are represented by the Canadian Office and Professional Employees Union (''COPEU'') and the International Brotherhood of Electrical Workers (''IBEW'') under collective agreements which expire on March 31, 2007 and March 31, 2011, respectively.

Tax Assessment

TGI has received a Notice of Assessment dated July 31, 2006 from the British Columbia Social Service Tax authority (the ''BC Tax Authority'') for the payment of $37.1 million of additional provincial sales tax and interest on the Southern Crossing Pipeline which was completed in 2000 (the ''Assessment''). In October 2006, TGI made a payment of $10 million pending its appeal of the Assessment as a good faith payment to forestall an order from the BC Tax Authority to provide full payment or security. On October 26, 2006, TGI filed an objection to the Assessment with the BC Tax Authority. The BCUC has allowed TGI to defer the $10 million payment pending resolution of TGI's objection to the Assessment.

Terasen Gas (Vancouver Island) Inc.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia. TGVI is a franchise under development and is supported by the Vancouver Island Natural Gas Pipeline Agreement, as discussed in more detail below.

TGVI has been operating for almost 15 years. Its combined system consists of approximately 615 kilometers of natural gas transmission pipelines and 3,250 kilometers of distribution mains. The combined system has a designed throughput capacity of 144 million cubic feet per day (155 TJ per day). TGVI serves approximately 85,000 residential, commercial and industrial customers along the Sunshine Coast and in various communities on Vancouver Island including Victoria and surrounding areas. TGVI's largest customers are the Vancouver Island Gas Joint Venture, representing seven large pulp and paper mills on Vancouver Island and the Sunshine Coast, and BC Hydro's contracted gas-fired electricity cogeneration facility at Elk Falls, Vancouver Island. During 2005, TGVI delivered approximately 33.6 PJ of gas through its system. The average rate base of TGVI approved by the BCUC for 2007 is approximately $482 million.

TGVI's natural gas supply is transported through TGI's pipeline system. All natural gas flows to TGVI are from this single source on the mainland and are dependent on the use of two undersea high-pressure transmission pipes.

Vancouver Island Natural Gas Pipeline Agreement

The transmission line to Vancouver Island and the distribution systems on Vancouver Island that are currently owned by TGVI were originally constructed between 1989 and 1991 with financial support provided by the provincial and federal governments which included repayable contributions of an aggregate of $75 million from these governments (the ''Repayable Contributions''). In December 1995, the financial support arrangements with the governments were restructured under several agreements, including the Vancouver Island Natural Gas Pipeline Agreement (''VINGPA'') which was entered into between the predecessors of Terasen and TGVI and the Province of British Columbia (the ''Province'').

Under the VINGPA, which runs through to December 31, 2011, the Province has agreed to provide TGVI with financial support in the form of gas royalties on deemed volumes of natural gas transported through the Vancouver

Island pipeline from 1996 through 2011, which decreases the cost of purchased gas by approximately 20%. The royalty payment recognized in 2006 was approximately $36.3 million.

In turn, under the VINGPA, Terasen is required to provide financial support of up to $120 million over the period from 1996 to 2011 to finance the principal amount of the revenue deficiencies incurred by TGVI. Annual revenue deficiencies are calculated as the difference between the approved cost of service and revenue actually received. This funding can be by way of subscription for Class A Instruments (redeemable preferred shares of TGVI) or Class B Instruments (promissory notes issued by TGVI) (''Class B Instruments''), as determined by the BCUC.

Prior to 2003, rates charged by TGVI to its customers were insufficient to recover the cost of service of TGVI in aggregate, meaning that revenues from the sale and transportation of natural gas resulted in an annual revenue deficiency. Terasen and TGVI's former shareholder funded these annual revenue deficiencies in accordance with the VINGPA. The aggregate of the annual revenue deficiencies was funded with Class B Instruments bearing interest at a rate of 275 basis points over the applicable five-year Canada bond rate. The accumulated revenue deficiency resulting from overall revenues being below the cost of service has been recorded in a revenue deficiency deferral account (''RDDA''). Since 2003, the aggregate annual revenues have exceeded the full cost of service and therefore TGVI has been in a revenue surplus position. The revenue surplus is used, in part, to pay down the RDDA balance as well as to pay the interest on the Class B Instruments described above. The BCUC has been directed to include in the cost of service an amount to amortize the RDDA balance over the shortest period reasonably possible, having regard to competitive energy sources and the desirability of rates. As at September 30, 2006, TGVI had issued and outstanding approximately $42 million of Class B Instruments.

As part of the December 1995 restructuring discussed above and concurrently with the entering into of the VINGPA, the predecessor to TGVI entered into the Pacific Coast Energy Pipeline Agreement (the ''PCEPA'') with the Government of Canada and the Province which set out the mechanism for the repayment of the $75 million Repayable Contributions owed to the federal and provincial governments. The PCEPA provides for scheduled repayments but also contemplates earlier non-scheduled prepayments in certain circumstances. Repayments on the $75 million Repayable Contributions go towards increasing the rate base on a dollar-for-dollar basis.

Vancouver Island Gas Joint Venture Transportation Agreement

TGVI provides gas transportation service to the seven pulp and paper mills under the long-term Vancouver Island Gas Joint Venture Transportation Service Agreement that was amended effective January 1, 2005 to extend it beyond the original renewal period by two years to December 31, 2012. The maximum daily volume of firm transportation service under the agreement was 20 TJ per day for 2005. In 2006, the maximum daily volume changed to 12.5 TJ per day for the remainder of the renewal period. The committed volume can be reduced to 8 TJ on twelve months' notice at any time on or after January 1, 2007.

Contractual Arrangements

TGVI has entered into a firm transportation agreement with BC Hydro to serve BC Hydro's gas supply needs at a gas-fired cogeneration plant at Elk Falls, Vancouver Island. The agreement, for 45 TJ per day, expires on December 31, 2007. BC Hydro has an option to extend the agreement for one year. BC Hydro has indicated that it is considering changing the Elk Falls facility from a baseload facility to a dispatchable facility, which will change the transportation agreement from firm to interruptible. Accordingly, there is no certainty with respect to the terms under which the firm transportation agreement with BC Hydro may be extended beyond 2007. Failure to extend the agreement will result in a reduction in TGVI's transportation revenues of approximately $13 million, which would be expected to be recovered through increased rates approved by the BCUC.

On February 16, 2005, the BCUC approved the construction by TGVI of a $100 million liquid natural gas storage facility, subject to several conditions including the execution of a long-term Transportation Service Agreement with BC Hydro backed by the capacity demand requirements of the Duke Point generation project. On June 17, 2005, BC Hydro announced its intention to abandon the Duke Point generation project on Vancouver Island as a result of a continuing appeal process. As a result, the expected construction timeline for TGVI's proposed storage facility has been delayed and, pending re-evaluation, will require BCUC approval prior to proceeding.

Gas Purchase Agreements

In order to acquire effective supply resources that ensure reliable natural gas deliveries to its customers, TGVI purchases supply from a select list of producers, aggregators and marketers by adhering to strict standards of counterparty credit worthiness and contract execution/management procedures. As of November 1, 2005, TGVI contracted approximately 12.5 TJ per day of baseload supply delivered off the Spectra Pipeline System. TGVI also purchased approximately 31.8 TJ per day of seasonal supply to meet the higher loads during the winter months of December 2005 to February 2006.

TGVI maintains storage contracts with Unocal Canada Limited at Aitken Creek Storage facility in northern British Columbia and Northwest Natural Gas Company at Mist Storage facility in Oregon. As at March 14, 2006, TGVI's Aitken Creek Storage contract consisted of 2.1 PJ of capacity with 13.6 TJ of daily deliverability and its Mist storage agreement consisted of 0.69 PJ of capacity with 26.4 TJ of daily deliverability. As at March 14, 2006, TGVI also had access to an estimated 21.1 TJ of daily peaking supply deliverability from various peaking supply arrangements.

Capital Program

TGVI's capital projects for the upcoming years are primarily associated with the expansion of the distribution system and the addition of new customers. The capital expenditures are expected to increase the rate base and expand the customer base. The 2007 revenue requirements approved by the BCUC for TGVI include capital expenditures of $53.7 million, which includes $20.8 million for the Whistler pipeline. The capital expenditures relating to customer growth on Vancouver Island represent approximately 9.1% of the capital budget for 2007, while the remaining amount relates to system expansion, capital betterments, replacements and life extensions.

On June 28, 2006, TGVI and TGWI received final approval from the BCUC to extend natural gas service to Whistler. Under the proposed arrangements, TGVI will extend its transmission system to serve TGWI by the construction of a 50-kilometer pipeline lateral from Squamish to Whistler. It is expected that the pipeline will cost $42.8 million and TGVI's contribution to the pipeline costs, including system conversion, will be approximately $20.8 million. TGWI will pay the remainder of the costs of the pipeline.

Employees

TGVI has approximately 105 employees. Its organized employees are represented by the COPEU and the IBEW under the TGI Collective Agreements. See ''— Terasen Gas Inc. — Employees'' above.

Terasen Gas (Whistler) Inc.

TGWI has owned and operated the propane distribution system at Whistler since 1987. It provides service to approximately 2,350 residential and commercial customers in the Whistler area of British Columbia. TGWI owns and operates two propane storage and vaporization plants and approximately 100 kilometers of distribution pipelines serving customers in the Whistler area. The propane distribution system in Whistler has grown far beyond the original expectations and beyond the size and scale of other similar propane distribution systems in British Columbia and Canada. Today, with annual deliveries exceeding 750,000 GJ, TGWI's propane system is unique in terms of the size of the customer base it serves and the scale of the facilities required by its continued operations. The average rate base of TGWI for 2006 was approximately $16.5 million.

On June 28, 2006, TGVI and TGWI received final approval from the BCUC to extend natural gas service to Whistler. Under the proposed arrangements, TGVI will extend its transmission system to serve TGWI by the construction of a 50-kilometer pipeline lateral from Squamish to Whistler and TGWI will convert its current piped propane system to natural gas. The pipeline, which is scheduled for completion in 2008 and will be co-ordinated with the current Sea-to-Sky Highway upgrade project, will allow TGWI to better service future demand. It is expected that the pipeline will cost $42.8 million and TGWI's contribution to the pipeline costs, including system conversion, will be approximately $22.0 million. TGVI will pay the remainder of the cost of the pipeline. Customer, management and operations services are provided to TGWI by TGI.

Non-Regulated — CustomerWorks Limited Partnership

CWP is a partnership between Terasen and Enbridge that provides shared customer services primarily to the companies' respective regulated operations, Terasen Gas and Enbridge Gas. Enbridge owns a 70% interest in CWP and Terasen owns a 30% interest.

The provision of services by CWP is governed by a customer service agreement dated January 1, 2002, as amended (the ''Customer Service Agreement''). The Customer Service Agreement was initially entered into between BC Gas Utility Ltd. (the predecessor of TGI) and CWP and was subsequently amended to, among other things, provide for the outsourcing of the services by CWP to Accenture Business Services for Utilities Inc., a company indirectly owned and operated by Accenture, and to extend the provision of services to TGVI and TGWI. The Customer Service Agreement was entered into for a five-year term, renewable for additional one-year terms.

The services provided under the Customer Service Agreement include customer contact, meter reading, billing, support, and credit and collection services. The Customer Service Agreement has been approved by the BCUC. The rates under the Customer Service Agreement have both a fixed and service volume based component, include minimum service standards and penalties and are based on market prices. In providing these services, CWP uses a customer information services system under a licence from Enbridge Commercial Services, a subsidiary of Enbridge. During the nine-month period ended September 30, 2006, TGI paid approximately $33.1 million to CWP under the Customer Service Agreement.

Regulation

The Terasen Gas natural gas distribution system operates wholly within British Columbia. Gas utilities which operate wholly within British Columbia are subject to the regulatory jurisdiction of the BCUC which derives its powers from the *Utilities Commission Act* (British Columbia). In addition to approving the rate base and new financings of gas utilities, the BCUC also approves the rates charged to customers. These rates are designed to recover the utilities' costs of providing service and allow the opportunity to meet financial commitments and earn a reasonable and fair ROE. The BCUC has jurisdiction to regulate and approve the terms and conditions under which gas utilities provide service.

As part of the establishment of the rates that a gas utility charges its customers, the BCUC establishes a rate base, approves a capital structure with which to finance such rate base, and is responsible for setting a reasonable and fair rate of return on the debt and equity in the approved capital structure. Rate base is the aggregate of the depreciated cost of property, plant and equipment that is used or useful in serving the public, certain deferral accounts and a reasonable allowance for working capital. The fair rate of return is established by determining the cost of individual components of the capital structure, including ROE, and weighting such costs to determine an aggregate rate of return on rate base. The rates that are established and the terms and conditions of service are contained in a schedule of published and public tariffs. Before any tariff can be put into effect, it must be filed with the BCUC. The BCUC has jurisdiction to approve or refuse any amendment submitted for filing and to determine the rates which should be charged by a utility for its services. The BCUC is required to have due regard, among other things, to fixing rates that are not unjust or unreasonable. In fixing rates the BCUC must determine that such rates reflect a fair and reasonable charge for service of the nature and quality furnished by the utility to its customers and that such rates are sufficient to yield the utility fair and reasonable compensation for its services and a fair and reasonable rate of return on its rate base.

The BCUC uses a future test year in the establishment of rates for a utility. Pursuant to this method, the BCUC forecasts the volume of gas that will be sold and transported, together with all of the costs of the utility (including the rate of return) that the utility will incur in the test year. Rates are fixed to permit the utility to collect all of its costs (including the rate of return) if the forecast sales and transportation volumes are achieved. The forecast sales volumes assume normal weather. Certain costs are fixed and will be incurred regardless of the actual volume of gas sold. Accordingly, if the actual volumes of gas sales are less than those forecast in the test year, the utility might not recover all of the fixed costs. Interest expense, taxes other than income taxes, depreciation and amortization, certain operations and maintenance costs, the portion of the cost of gas that is fixed, such as demand charges or reservation fees, and the fixed portion of transportation costs have the effect of being virtually fixed costs.

In addition to application for approval of interim and annual rate changes, the gas utilities may apply from time to time to the BCUC for rate changes to give effect to the changes in costs beyond the control of the utilities.

The table below summarizes regulatory information pertaining to decisions made by the BCUC with respect to TGI and TGVI. While also regulated by the BCUC, similar regulatory information with respect to TGWI is not available from publicly available BCUC filings.

	Regulated Values				
	2007(1)	2006	2005	2004	2003
TGI					
Rate base ($M)	2,474	2,506	2,406	2,310	2,281
Deemed common equity component of total capital structure (%)	35	35	33	33	33
Allowed ROE (%)	8.37	8.80	9.03	9.15	9.42
TGVI					
Rate base ($M)	482	470	453	441	437
Deemed common equity component of total capital structure (%)	40	40	35	35	35
Allowed ROE (%)	9.07	9.50	9.53	9.65	9.92

(1) As approved by the BCUC.

Terasen Gas Inc.

TGI's allowed ROE is determined annually based on a formula that applies a risk premium to a forecast of long-term Government of Canada Bond yields. On June 30, 2005, TGI applied to the BCUC to increase the deemed equity components from 33% to 38%. The application also requested an increase in allowed ROEs from the levels that result from the then-current formula, which would have yielded 8.29% for TGI in 2006. The BCUC rendered its decision on the application on March 2, 2006, to be effective as of January 1, 2006. The generic ROE formula for a benchmark utility in British Columbia was changed such that it will be reset annually from a forecast of 30-year Canada Bonds plus a 3.90% risk premium when the forecast yield on 30-year Government of Canada Bonds is 5.25%. The risk premium is adjusted annually by 75% of the difference between 5.25% and the forecast yield on 30-year Government of Canada Bonds. For 2007, the forecast 30-year Canada Bond yield is 4.22% resulting in an ROE for TGI of 8.37%.

Two mechanisms to mitigate unanticipated changes in costs and sales volumes, such as changes caused by weather, have been implemented specifically for TGI. The first relates to the recovery of all gas costs through deferral accounts which capture all variances (overages and shortfalls) from forecasts. Balances are either refunded to or recovered from customers as determined by the BCUC. The deferral accounts are called the Commodity Cost Reconciliation Account (''CCRA'') and the Midstream Cost Reconciliation Account (''MCRA''). The second mechanism seeks to stabilize delivery revenues from residential and commercial customers through a deferral account that captures variances in the forecast-versus-actual customer use throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism (''RSAM''). In February 2001, the BCUC issued guidelines for quarterly calculations to be prepared to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas and to ensure that rate stabilization account balances are recovered on a timely basis. The balance in the RSAM account at December 31, 2006 was approximately $36 million and the BCUC has approved $11.5 million of this balance to be recovered in 2007 through a rate rider.

The RSAM and CCRA/MCRA accounts reduce TGI's earnings exposure to risks associated with volatility of gas costs and consumer demand. Variances in demand by large volume, industrial transportation customers are not covered by these deferral accounts as their usage is more predictable and less likely to be significantly affected by weather.

The net balances of the RSAM and CCRA/MCRA accounts increased to a receivable of approximately $148.8 million as at September 30, 2006 from a payable of approximately $9.0 million as at December 31, 2005. In order to ensure that the balances in the CCRA/MCRA accounts are recovered on a timely basis, TGI prepares and files quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas costs.

TGI also has in place deferral accounts to absorb short-term and long-term interest rate fluctuations. The interest rate deferral accounts which were in place during 2006 effectively fixed the interest expense on short-term funds attributable to TGI's regulated assets at 4.00% during 2006. The effective fixed short-term interest rate for 2007 has been set at 4.75%. Any variations from these rates throughout the year are recorded in deferral accounts and are subsequently either refunded to or recovered from customers as determined by the BCUC.

In 2003, TGI received BCUC approval of a Negotiated Settlement of a 2004-2007 PBR Plan (the ''TGI Settlement''). The TGI Settlement, which took effect January 1, 2004, establishes a process for determining TGI's delivery charges and incentive mechanisms for improved operating efficiencies. The four-year agreement includes incentives for TGI to operate more efficiently through sharing of the benefits of cost reductions among TGI and its customers. It includes ten service quality indicators designed to ensure TGI provides appropriate service levels and sets out the requirements for an annual review process which will provide a forum for discussion between TGI and interested parties regarding TGI's current performance and future activities. In January 2007, TGI made application to the BCUC to extend the TGI Settlement to 2009.

Operation and maintenance costs and base capital expenditures are subject to an incentive formula which permits recovery of increasing costs due to customer growth and inflation. Operating costs are subject to an adjustment factor based on 50% of inflation during the first two years and 66% of inflation during the last two years. Base capital expenditure amounts are a function of customer numbers and projected customer additions. During the annual review process, non-controllable expenses and extraordinary capital expenditures can be added to or subtracted from revenue requirements under the terms of the TGI Settlement.

The TGI Settlement provides for a 50/50 customer/shareholder sharing mechanism of earnings above or below the allowed ROE. When TGI's earned ROE is greater than 150 basis points above or below the allowed ROE for two consecutive years, the PBR mechanism may be reviewed. The following table sets out the allowed ROE, the earned ROE (before sharing) and the customer share under the sharing mechanism.

TGI Earned ROEs and Shared Earnings through PBR

	2006(1)	2005	2004
Allowed ROE (%)	8.80	9.03	9.15
Earned ROE (%)	10.10	10.78	9.34
Customer share (pre-tax)($M)	8.2	10.5	1.1

(1) Projected as filed by TGI in the 2007 Revenue Requirement Filing.

Terasen Gas (Vancouver Island) Inc.

Pursuant to BCUC orders from 2003 onwards, TGVI's rates have been set so as to fully recover its cost of service plus an amount for the timely amortization of the RDDA in accordance with the government directives. To permit recovery of the outstanding balance in the RDDA, TGVI's rates for residential and commercial customers are set at levels in excess of TGVI's cost of service, but are effectively capped at a comparable price of competitive alternative fuels. TGVI renewed its regulatory settlement in late 2005 for a two-year period, effective January 1, 2006. It provides for a continuation of the operation and maintenance cost incentive arrangements previously in place. The allowed ROE for TGVI was 9.53% for 2005 compared to 9.65% in 2004. TGVI's ROE for 2006 is 9.50% and TGVI's deemed equity component of its capital structure for 2006 is 40%. The 2007 approved ROE for TGVI has been set at 9.07%.

TGVI's approved rate design methodology provides, in effect, that to the extent that cost of service inputs change over time, TGVI's rates will reflect a variable RDDA amortization. The rates generally are set to be equivalent to 90% of comparable electricity price. The RDDA amortization was approximately $12.4 million in 2005 and approximately $6.9 million in 2006. The RDDA has been amortized from approximately $87.9 million as at December 31, 2002 to approximately $41.4 million as at December 31, 2006.

In November 2005, TGVI received BCUC approval of a Negotiated Settlement (the ''TGVI Settlement'') of 2006-2007 revenue requirements. The two-year TGVI Settlement, which took effect as of January 1, 2006, establishes a process for determining TGVI's delivery charges and offers incentive mechanisms for improved operating efficiencies. TGVI is permitted to retain 100% of earnings from savings of controllable operating and maintenance expenses from forecast and TGVI will not be provided any relief from increased controllable operating and maintenance expenses. The operating and maintenance expense forecast is based on actual 2005 costs, adjusted for changes outside of management's control, expected savings from operational synergies with TGI, 66% of inflation and customer growth. TGVI has managed actual operating and maintenance expenses close to forecast. In January 2007, TGVI made an application to the BCUC to extend the TGVI Settlement to 2009.

Competition

Natural gas has maintained a competitive advantage in terms of pricing when compared with alternative sources of energy in British Columbia, despite the significant increase in natural gas commodity prices since 1999. Regulated electricity prices in British Columbia are currently set based on the historical average production costs which are lower than the market price of electricity. Current regulated electricity prices are only marginally higher than comparable, market-based natural gas prices. A further sustained increase in natural gas commodity prices could cause natural gas in British Columbia to be priced at or above electricity, thereby decreasing the use of natural gas by customers.

Hedging

Derivative instruments are used to hedge exposure to fluctuations in natural gas prices and interest rates. The majority of the natural gas supply contracts have floating, rather than fixed, prices. Natural gas price swap contracts are used to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in deferral accounts (MCRA and CCRA) and, subject to BCUC approval, passed through to customers in future rates.

TGI's short-term borrowings and variable rate long-term debt are exposed to interest rate risk which TGI manages through the use of interest rate derivatives. Any resulting gains or losses are recorded in interest rate deferral accounts and, subject to BCUC approval, passed through to consumers in future rates.

Financing Arrangements

Debentures

Terasen has issued and outstanding two series of unsecured medium term note debentures (''Terasen MTN Debentures''), which are governed by a Trust Indenture dated November 21, 2001 between Terasen (as successor to BC Gas Inc.) and CIBC Mellon Trust Company (the ''2001 Indenture''), as amended and supplemented by a First Series Supplement dated November 22, 2001 (the ''First Supplement''). The aggregate principal amount of debentures that may be issued under the 2001 Indenture is unlimited, subject to the restrictions set forth therein. As at September 30, 2006, Terasen had issued and outstanding $200 million principal amount of 6.30% Series 1 MTN Debentures due December 1, 2008 and $125 million principal amount of 5.56% Series 3 MTN Debentures due September 15, 2014. The First Supplement includes a positive covenant of Terasen that, so long as any MTN Debentures remain outstanding, it shall not create, assume, issue or otherwise incur or become liable for any Funded Indebtedness unless immediately thereafter the Funded Indebtedness of Terasen and its subsidiaries will not be in excess of 75% of Total Consolidated Capitalization. Funded Indebtedness means indebtedness that matures more than 18 months after such indebtedness was incurred, except for non-recourse debt to finance specific assets or subordinated debt. Total Consolidated Capitalization means the sum of (a) the principal amount of consolidated Funded Indebtedness of Terasen and its subsidiaries, (b) the total capital of Terasen, (c) the principal amount of all subordinated debt of Terasen, (d) the sum of consolidated contributed or capital surplus and retained earnings of Terasen, and (e) provision for future income taxes of Terasen.

On April 19, 2000, Terasen issued $125 million of 8.0% unsecured capital securities (the ''Capital Securities'') with a term to maturity of 40 years. The Capital Securities were issued under the terms of a Trust Indenture dated April 19, 2000 between Terasen (as successor to BC Gas Inc.) and CIBC Mellon Trust Company (the ''2000 Indenture''). Terasen may elect to defer payments on the Capital Securities for extension periods not exceeding 10 consecutive semi-annual periods. Terasen may settle such deferred payments in either cash or common shares and has the option to settle principal at maturity through the issuance of common shares at 90% of their market price. The 2000 Indenture provides that if Terasen defers any interest payment on the Capital Securities, it is not permitted to pay dividends on, or purchase or redeem, its common shares for so long as such interest payments are deferred. The Capital Securities are exchangeable at the option of the holder on or after April 19, 2010 for common shares of Terasen at a price equal to the greater of $1 per share and 90% of the market price.Terasen may, at its option, redeem the Capital Securities in whole at a redemption price which, if the Capital Securities are redeemed prior to April 19, 2010, is equal to the greater of Canada Yield Price (as defined in the 2000 Indenture) and 100% of the principal amount of the Capital Securities, together in each case with accrued and unpaid interest, or if the Capital Securities are redeemed on or after April 19, 2010, at a price that is equal to 100% of the principal amount outstanding plus any accrued and unpaid interest.

TGI has issued and outstanding unsecured debentures and medium-term note debentures which are governed by a Trust Indenture dated November 1, 1977 between TGI (as successor to Inland Natural Gas Co. Ltd.) and CIBC Mellon Trust Company (as successor to National Trust Company, Limited), as amended and supplemented (the ''1977 Indenture''). The aggregate principal amount of debentures that may be issued under the 1977 Indenture is unlimited, subject to the restrictions set forth therein. As at September 30, 2006, TGI had issued and outstanding $59.9 million principal amount of 10.75% debentures, Series E due June 8, 2009, and an aggregate of $1,008 million of medium-term note debentures with fixed rates of interest ranging from 5.55% to 6.95% or with floating interest rates, and maturities of not less than one year. The Fourth Supplemental Indenture dated June 1, 1989 and the Tenth Supplemental Indenture dated November 15, 1993 contain certain restrictions on the ability of TGI to issue any debt securities with maturities of more than 18 months, unless certain financial tests are met and subject to certain exceptions.

TGI also has issued and outstanding Series A and Series B Purchase Money Mortgages (the ''Purchase Money Mortgages''), which are secured equally and rateably by a first fixed and specific mortgage and charge on TGI's gas distribution system in the lower mainland of British Columbia that was acquired by TGI from BC Hydro. The Purchase Money Mortgages are governed by a Trust Indenture dated December 3, 1990 between TGI (as successor to B.C. Gas Inc.), Inland Energy Corp. and CIBC Mellon Trust Company (as successor to National Trust Company), as amended and supplemented (the ''1990 Indenture''). The aggregate principal amount of Purchase Money Mortgages that may be issued under the 1990 Indenture is limited to $425 million. As at September 30, 2006, TGI had issued and outstanding $74.9 million aggregate principal amount of 11.80% Series A Purchase Money Mortgages due September 30, 2015 and $200 million aggregate principal amount of $10.30% Series B Purchase Money Mortgages due September 30, 2016.

Credit Facilities

On May 5, 2006, Terasen entered into a Credit Agreement with The Toronto-Dominion Bank, as administrative agent, and the institutions named therein, as lenders (the ''Terasen Credit Agreement''). The Terasen Credit Agreement provides a committed $450 million revolving credit facility which matures on May 5, 2009. The interest rate payable on advances under the credit facility varies based on the type of advance. The credit facility can be used for Terasen's general corporate purposes. The Terasen Credit Agreement contains customary representations and warranties and positive and negative covenants, including a requirement that Terasen maintain a total debt-to-capitalization ratio not higher than 0.75:1 and an interest coverage ratio not less than 1.25:1. The Terasen Credit Agreement contains customary events of default.

On June 21, 2006, TGI entered into a Credit Agreement with Canadian Imperial Bank of Commerce, as administrative agent, lead arranger and sole bookrunner, The Bank of Nova Scotia, as syndication agent and the other lenders identified therein (the ''TGI Credit Agreement''). The TGI Credit Agreement provides a committed $500 million revolving credit facility. The interest rate payable on accommodations under the TGI Credit Agreement varies based on the type of accommodation. The facility can be used for refinancing indebtedness of TGI and for general corporate purposes, including as back-up for TGI's commercial paper program. The TGI Credit Agreement is extendible annually for an additional 365 days at the option of the lenders and matures on June 21, 2009. The TGI Credit Agreement contains customary representations and warranties and positive and negative covenants, including a requirement that TGI maintain a total debt to capitalization ratio not higher than 0.75:1. The TGI Credit Agreement contains customary events of default.

On January 13, 2006, TGVI entered into a Credit Agreement with Royal Bank of Canada, as administrative agent, RBC Capital Markets, as lead arranger and bookrunner, National Bank Financial, as syndication agent, and The Bank of Nova Scotia, as documentation agent, and the other lenders identified therein (the ''TGVI Credit Agreement''). The TGVI Credit Agreement provides for a five-year unsecured, committed, revolving credit facility of $350 million. A portion of the facility was used to refinance TGVI's term facility of $209.5 million. While the borrowings under this facility are short-term bankers' acceptances, the underlying credit facility on which the advances are provided is committed through to January 2011 and the borrowings are primarily to support the longer-term rate base assets of TGVI. The facility can be used for refinancing indebtedness of TGVI and for general corporate purposes, including for capital expenditures. The TGVI Credit Agreement contains customary representations and warranties and positive and negative covenants, including a requirement that TGVI maintain a ratio of institutional indebtedness-to-total capitalization not higher than 0.70:1 and a ratio of earnings to interest expense of at least 2.0:1. The TGVI Credit Agreement contains customary events of default, including a cross default under the VINGPA and certain other agreements.

Concurrently with the TGVI Credit Agreement, TGVI also entered into a $20 million, seven-year unsecured, committed, non-revolving credit facility with Royal Bank of Canada which is to be used only for purposes of funding up to 65% of each repayment of the Repayable Contributions under the PCEPA. The terms of this facility are substantially similar to those contained in the TGVI Credit Agreement. This facility ranks junior to repayment of the Class B Instruments held by Terasen. See ''— Terasen Gas (Vancouver Island) Inc. — Vancouver Island Natural Gas Pipeline Agreement'' above.

The following summary outlines the credit facilities of Terasen, TGI and TGVI as at September 30, 2006.

(in millions of dollars)	Terasen	TGI	TGVI	Total
Total credit facilities	450	500	370	1,320
Credit facilities utilized Borrowings	176	207	284	667
Letters of credit outstanding	73	43.6	—	116.6
Credit facilities available	201	249.4	86	536.4

ACQUISITION AGREEMENT

Fortis has entered into the Acquisition Agreement dated February 26, 2007 with 3211953 Nova Scotia Company (''3211953'') and Kinder Morgan for the purchase of all of the issued and outstanding shares of Terasen. The Acquisition Agreement provides that prior to the closing of the Acquisition, Kinder Morgan will transfer all of the issued and outstanding shares of Terasen which it currently owns to 3211953. In this section of the Prospectus, ''Vendor'' means Kinder Morgan prior to such transfer, and 3211953 upon the occurrence of such transfer. The Acquisition is not a transaction with an informed person, associate or affiliate of Fortis (as such terms are defined in National Instrument 51-102 — *Continuous Disclosure Obligations*).

Purchase Price

The purchase price under the Acquisition Agreement is $3.7 billion, including the assumption of approximately $2.3 billion of consolidated indebtedness of Terasen and the balance in cash. The cash portion of the purchase price (the ''Cash Purchase Price'') will be equal to $1.801 billion minus the unconsolidated indebtedness of Terasen outstanding on the closing of the Acquisition, which management of Fortis expects to be at least $450 million.

Representations and Warranties

Under the Acquisition Agreement, the Vendor and Fortis have made various representations and warranties. The Vendor's representations and warranties relate to, among other things, organization and status, capitalization, title, authority to enter into the Acquisition Agreement and no conflict, consents and approvals, absence of defaults under constating documents or material agreements, absence of certain material changes or events since December 31, 2006, employment matters, pension and employee benefits, securities regulatory filings, reports and financial statements, compliance with laws, possession of permits, restrictions on business activities, legal or regulatory proceedings, material contracts, tax matters, intellectual property, books and records, environmental matters, insurance, brokerage fees, management controls and no U.S. operations. Fortis' representations and warranties relate to, among other things, organization and status, authority to enter into the Acquisition Agreement and no conflict, consents and approvals, availability of financing, legal proceedings, no knowledge of a breach of the Vendor's representations or warranties or disclosure, brokerage fees, nature of investment and independent investigation.

Covenants

The Vendor and Fortis have made covenants relating to the closing of the Acquisition and related matters. In particular, the Vendor has agreed to the following during the period from the date of the Acquisition Agreement until the closing:

(a) Conduct of Business. Terasen and Terasen Gas will carry on business in the usual and ordinary course of business consistent with past practices, maintain material properties and assets in good repair and use commercially reasonable efforts to preserve present business organizations, officers, employees, customers and suppliers;

(b) Dividends. Terasen and Terasen Gas will not declare or pay any dividends on capital stock, except for dividends (i) by TGI or TGVI to Terasen up to an amount such that, immediately after giving effect to such payment, TGI or TGVI, as the case may be, will have a ratio of common equity to total capital of at least 35% and 40%, respectively, and (ii) by Terasen up to but not exceeding the aggregate amount of dividends received by it from TGI and TGVI.

(c) Capital Expenditures. Terasen and Terasen Gas will not make or commit to make any capital expenditures in excess of $5 million, other than (i) to replace or repair damaged or destroyed facilities, (ii) budgeted capital expenditures, (iii) expenditures approved by the BCUC, or (iv) expenditures required by law;

(d) Employees and Benefits. Terasen and Terasen Gas will not increase compensation or benefits for employees, except nominal increases for people who are not officers or directors made in the ordinary course of business consistent with past practice;

(e) Rates. Subject to applicable law, Terasen and Terasen Gas will not implement any changes in any rates or charges (other than changes under existing tariffs, rate schedules or performance-based rate-making arrangements authorized by the BCUC), standards of service or accounting, or execute any agreement relating thereto that could reasonably be expected to materially decrease the revenues of the business unit implementing the change;

(f) Borrowings. Terasen and Terasen Gas will not incur any indebtedness other than in the ordinary course of business and subject to the specified exceptions in the Acquisition Agreement;

(g) Pre-Closing Reorganization. Terasen will complete the Pre-Closing Reorganization prior to closing; and

(h) Discharge of Guarantees. The Vendor shall cause Terasen and Terasen Gas to be discharged from all obligations under certain guarantees by Terasen and Terasen Gas for the benefit of the petroleum transportation business of Terasen.

In addition, the Vendor and Fortis have agreed to use their reasonable efforts to obtain all material authorizations, consents, orders and approvals and to make all necessary filings with the relevant government authorities as required under the Acquisition Agreement.

Indemnities

Pursuant to the Acquisition Agreement, the Vendor has agreed, subject to certain limits, to indemnify and save harmless Fortis and its affiliates, and Fortis, subject to certain limits, has agreed to indemnify and save harmless the Vendor and its affiliates in respect of all losses sustained or incurred by the other resulting from (i) certain misrepresentations or breaches of warranty relating to title to the shares of Terasen and Terasen Gas, organization, corporate status, authority to enter into the Acquisition Agreement, and no breach of constating documents or any laws (the ''Title Warranties''), (ii) any breach of the covenants or obligations to be performed following the closing of the Acquisition contained in the Acquisition Agreement, (iii) the Pre-Closing Reorganization and the operations of the petroleum transportation business of Terasen, in the case of indemnification by the Vendor, and (iv) in the case of indemnification by Fortis, the operations of the Terasen and Terasen Gas businesses (provided that the facts giving rise to the losses do not constitute a breach of the representations and warranties of the Vendor). The indemnities provided by the Vendor or Fortis, as the case may be, with respect to breaches of covenants and obligations to be performed following the closing of the Acquisition are limited in that claims may only be made when (i) the losses suffered exceed $500,000 in each instance or (ii) the aggregate of all such losses exceeds 2.5% of the Cash Purchase Price and, in the latter case, only to the extent of such excess. The maximum amount that can be claimed by Fortis under the indemnity provisions of the Acquisition Agreement is limited to 10% of the Cash Purchase Price with respect to claims for any breach of the covenants or obligations of the Vendor following the closing of the Acquisition, and 100% of the Cash Purchase Price with respect to claims for breaches of the Title Warranties. The maximum amount that can be claimed by the Vendor under the indemnity provisions of the Acquisition Agreement is limited to 10% of the Cash Purchase Price with respect to claims for any breach of the covenants or obligations of Fortis following the closing of the Acquisition contained in the Acquisition Agreement and 100% of the Cash Purchase Price with respect to claims for breaches of the Title Warranties. Claims sustained or incurred by Fortis as a result of the Pre-Closing Reorganization and the operations of the petroleum transportation business of Terasen, and by the Vendor in respect of the operations of the Terasen and Terasen Gas businesses, are not subject to any minimum or maximum limits.

Closing Conditions

The Acquisition Agreement provides that the obligation of Fortis or the Vendor to complete the Acquisition is subject to the fulfillment of a number of conditions, each of which may be waived by such party, including the following:

(a) Accuracy of Representations and Warranties. The representations and warranties of the other party under the Acquisition Agreement are true and correct as of the date of the Acquisition Agreement and as of the closing date (except for representations and warranties made as of an earlier date, which must be true and correct as of such earlier date), except where the failure of such representations and warranties to be true and correct would not be reasonably likely, individually or in the aggregate, to have a Material Adverse Effect on the other party. ''Material Adverse Effect'' is defined in the Acquisition Agreement to mean any adverse and material change relating to the condition (financial or otherwise), results of operations or business of either party that is material to such party and its subsidiaries, taken as a whole, or in the case of the Vendor, that is material to Terasen and Terasen Gas, taken as a whole;

(b) Performance of Covenants. The other party has performed and complied with its material covenants and agreements under the Acquisition Agreement in all material respects;

(c) Legal Proceedings. There must not be any decree, injunction or ruling that would prevent or otherwise make the Acquisition illegal;

(d) Consents and Approvals. Each party has received the governmental and regulatory consents and approvals required to be obtained by it under the Acquisition Agreement. The regulatory approvals that must be obtained prior to the closing of the Acquisition include:

   (i) approval by the BCUC of the transfer of the shares of Terasen to Fortis or a subsidiary of Fortis pursuant to the *Utilities Commission Act* (British Columbia); and

   (ii) one of the following has occurred: (i) an advance ruling certificate has been issued in respect of the Acquisition pursuant to section 102 of the *Competition Act* (Canada) (the ''Competition Act''); (ii) the parties have received written advice that the Commissioner has concluded that she does not have sufficient grounds to initiate proceedings before the Competition Tribunal to challenge the Acquisition under the merger provisions of the Competition Act; or (iii) any applicable waiting period pursuant to section 123 of the Competition Act has expired or been earlier terminated or waived.

(e) Pre-Closing Reorganization. The Pre-Closing Reorganization has been completed.

Termination

The Acquisition Agreement may be terminated by Fortis or the Vendor at any time prior to closing in certain circumstances, including:

(a) the mutual agreement of Fortis and the Vendor;

(b) if the other party has not satisfied the conditions that its representations and warranties under the Acquisition Agreement be true and correct and that it has performed in all material respects the material covenants and agreements required to be performed by it prior to the closing date, and such condition has not been waived on or before the closing date by the party wishing to terminate;

(c) if a government authority issues a final order or injunction restraining or prohibiting the Acquisition;

(d) if prior to the closing, the other party provides additional information disclosing facts that would constitute a breach of such other party's representations and warranties under the Acquisition Agreement and such breach would have a Material Adverse Effect on the party wishing to terminate the Acquisition Agreement, if notice of termination is provided within 10 days of receipt of the relevant information; or

(e) if the closing has not occurred on or before November 30, 2007, unless the failure to close by such date is due to the party wishing to terminate the Acquisition Agreement not having fulfilled its obligations under the agreement.

Kinder Morgan Guarantee

Pursuant to the Acquisition Agreement, Kinder Morgan has irrevocably and unconditionally guaranteed the full and complete performance by 3211953 of all of the obligations of 3211953 under the Acquisition Agreement, such guarantee to be effective upon the transfer by Kinder Morgan of all of the issued and outstanding shares of Terasen to 3211953 prior to the closing of the Acquisition.

FINANCING OF THE ACQUISITION

For purposes of financing the Acquisition, on February 26, 2007, Fortis obtained a commitment letter from Canadian Imperial Bank of Commerce providing for an aggregate of $1.425 billion non-revolving term credit facilities in favour of Fortis consisting of a facility in the amount of $925 million (''Facility A'') and a facility in the amount of $500 million (''Facility B'') (together with ''Facility A'', the ''Credit Facilities''). The Credit Facilities would be sufficient, if necessary, to fund the full Cash Purchase Price for the Acquisition.

The Credit Facilities are unsecured single borrowing credit facilities to be used by Fortis, to the extent required, to finance the payment of the Cash Purchase Price for the Acquisition. Any amount not drawn down under the Credit Facilities will be cancelled after the initial borrowing. Facility A and Facility B will mature on the second and third anniversary of the initial extension of credit under Facility A and Facility B, respectively.

The credit agreement pursuant to which the Credit Facilities will be extended (the ''Credit Agreement'') will contain certain prepayment options in favour of Fortis and certain prepayment obligations upon the occurrence of certain events. In particular, the net proceeds of any equity or debt offering by Fortis (other than certain permitted equity or debt offerings for strategic investments) will be required to be used to prepay the Credit Facilities and any prepayment under the Credit Facilities may not be re-borrowed. Fortis may prepay any balance outstanding under the Credit Facilities without penalty, provided that any such prepayment is in an amount of at least $10 million and subject to any breakage costs being for the account of Fortis.

The Credit Agreement will contain customary representations and warranties and affirmative and negative covenants of Fortis. As part of these covenants, Fortis will be required to maintain a consolidated debt to consolidated capitalization ratio of not more than 0.85:1 after the date of the Acquisition Agreement until the first anniversary of the closing of the Acquisition and 0.75:1 at any time thereafter. These ratios will reduce automatically to 0.75:1 and 0.70:1 at any time during those respective periods, if Fortis has received, free from any escrow conditions, aggregate proceeds from equity issuances of at least $700 million. The Credit Agreement will contain customary events of default. In addition, any failure by Fortis to maintain an investment grade credit rating will constitute an event of default under the Credit Agreement.

Customary fees are payable by Fortis in respect of the Credit Facilities and amounts outstanding under the Credit Facilities will bear interest at market rates.

The net proceeds from the Offering will be used to reduce the amount of the Credit Facilities. Fortis expects that the remainder of Credit Facilities will be repaid from the proceeds of one or more offerings of Common Shares, preferred shares and/or long-term debt.

CAPITALIZATION

The following table sets out the consolidated capitalization of the Corporation as at September 30, 2006 and after giving effect to the Offering (assuming no exercise of the Over-Allotment Option), the issue of 5,170,000 Common Shares on January 18, 2007, the issue of $110 million aggregate principal amount of senior unsecured debentures by FortisAlberta on January 3, 2007, the drawdown of $139.3 million under the Credit Facilities and completion of the Acquisition. The financial information set out below should be read in conjunction with the unaudited consolidated financial statements incorporated by reference into the Prospectus and the unaudited *pro forma* consolidated financial statements included in the Prospectus and, in each case, the notes thereto.

	Outstanding at September 30, 2006	*Pro forma* outstanding at September 30, 2006
	(in millions of dollars)	
Total debt (net of cash)	2,296.1	4,863.0(2)
Preference shares (1)	319.5	319.5
Shareholders' equity		
Securities offered hereby	Nil	974.2
Common shares	822.5	968.1(2)
Preference shares	122.5	122.5
Contributed surplus	4.3	4.3
Equity portion of convertible debentures	1.4	1.4
Foreign currency translation adjustment	(17.8)	(17.8)
Retained earnings	472.2	472.2
Total capitalization	4,020.7	7,707.4

(1) These preference shares are classified as long-term liabilities in the financial statements of Fortis.

(2) After giving effect to the Offering (assuming no exercise of the Over-Allotment Option), the issue of 5,170,000 Common Shares on January 18, 2007, the issue of $110 million aggregate principal amount of senior unsecured debentures by FortisAlberta on January 3, 2007, the drawdown of $139.3 million under the Credit Facilities and completion of the Acquisition.

PRICE RANGE AND TRADING VOLUME OF THE COMMON SHARES

The outstanding Common Shares of Fortis are traded on the TSX under the trading symbol ''FTS''. The following table sets forth the reported high and low trading prices and trading volumes of the Common Shares as reported by the TSX from January 2006.

Period	High	Low	Volume
2006			
January	$24.60	$22.76	3,981,812
February	23.76	22.00	7,087,013
March	23.50	21.65	6,775,211
April	22.95	20.89	3,813,271
May	24.84	20.36	7,241,148
June	24.60	21.16	3,707,157
July	23.40	21.99	2,328,812
August	25.48	22.15	6,214,513
September	25.40	24.00	2,553,872
October	25.65	24.12	7,362,894
November	28.74	25.15	6,234,745
December	30.00	28.01	2,793,265
2007			
January	30.00	26.72	6,030,480
February	27.96	26.00	8,612,015
March 1 to 6	26.81	26.16	2,204,514

On March 6, 2007, the closing price of the Common Shares was $26.80.

SHARE CAPITAL OF FORTIS

The authorized share capital of the Corporation consists of an unlimited number of Common Shares, an unlimited number of First Preference Shares issuable in series and an unlimited number of Second Preference Shares issuable in series, in each case without nominal or par value. As at March 6, 2007, 109,407,397 Common Shares, 5,000,000 First Preference Shares, Series C, 7,993,500 First Preference Shares, Series E and 5,000,000 First Preference Shares, Series F were issued and outstanding.

DIVIDEND POLICY

Dividends on the Common Shares are declared at the discretion of the Board of Directors of Fortis. The Corporation paid cash dividends on its Common Shares of $0.67 in 2006, $0.59 in 2005 and $0.54 in 2004. On December 7, 2006, the Fortis Board of Directors declared a first quarter dividend of $0.19 per Common Share, payable on March 1, 2007 to holders of record on February 2, 2007. On February 8, 2007, Fortis announced that its Board of Directors had declared a second quarter dividend of $0.21 per Common Share, payable on June 1, 2007 to holders of record on May 4, 2007. This dividend represents an increase of 10.5% in the quarterly Common Share dividend of the Corporation, which is the second increase in twelve months. Fortis has increased its annual dividend paid for 34 consecutive years.

Regular quarterly dividends at the prescribed annual rate have been paid on all of the First Preference Shares, Series C, the First Preference Shares, Series E and the First Preference Shares, Series F, respectively. On December 7, 2006, the Fortis Board of Directors also declared a first quarter dividend on each such series of First Preference Shares in accordance with the applicable prescribed annual rate, in each case payable on March 1, 2007 to holders of record on February 2, 2007.

DESCRIPTION OF COMMON SHARES

Dividends

Holders of Common Shares are entitled to dividends on a *pro rata* basis if, as and when declared by the Board of Directors of Fortis. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board of Directors of Fortis may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

Liquidation, Dissolution or Winding-Up

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Voting Rights

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and to one vote in respect of each Common Share held at such meetings.

DETAILS OF THE OFFERING

Subscription Receipts

The Subscription Receipts will be issued on the Closing Date (as defined below) pursuant to the Subscription Receipt Agreement. The Escrowed Funds will be delivered to and held by the Escrow Agent and invested in short-term interest bearing or discount debt obligations issued or guaranteed by the Government of Canada or a province, or one or more of the five largest Canadian chartered banks, provided in all cases that such obligation is rated at least R1 (middle) by DBRS Limited or an equivalent rating from an equivalent rating service, pending satisfaction of the Release Conditions.

If the Release Conditions are satisfied prior to 5:00 p.m. (Toronto time) on November 30, 2007, the Corporation will forthwith execute and deliver a notice of satisfaction and will issue and deliver to the Escrow Agent one Common Share for each Subscription Receipt then outstanding (subject to any applicable adjustment). The Common Shares will be available for delivery commencing on the second business day after the delivery of such notice. The holders of Subscription Receipts will receive, without payment of any additional consideration, one Common Share for each Subscription Receipt held plus an amount equal to the dividends declared on the Common Shares by the Corporation, if any, for which record dates have occurred during the period from the Closing Date to the date of issuance of the Common Shares in respect of the Subscription Receipts. Forthwith upon the Release Conditions being satisfied and the required notice being delivered to the Escrow Agent, the Escrowed Funds, together with interest earned and income generated thereon, will be released to Fortis.

In the event that the Release Conditions are not satisfied, or if the Acquisition Agreement is terminated, prior to the Termination Time, holders of Subscription Receipts shall, commencing on the second business day following the Termination Time, be entitled to receive from the Escrow Agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned or income generated on such amount. The Escrowed Funds will be applied toward payment of such amount.

In the event that, prior to the date of issue of a Common Share in respect of a Subscription Receipt, there is a subdivision, consolidation, reclassification or other change of the Common Shares or any reorganization, amalgamation, merger or sale of all or substantially all of the Corporation's assets, the Subscription Receipts will thereafter evidence the right of the holder to receive the securities, property or cash deliverable in exchange for or on the conversion of or in respect of the Common Shares to which the holder of a Common Share would have been entitled immediately after such event. Similarly, any distribution to all or substantially all of the holders of Common Shares of rights, options, warrants, evidences of indebtedness or assets will result in an adjustment in the number of Common Shares to be issued to holders of Subscription Receipts. Alternatively, such securities, evidences of indebtedness or assets may, at the option of the Corporation, be issued to the Escrow Agent and delivered to holders of Subscription Receipts on exercise thereof. In case the Corporation, after the Closing Date, takes any action affecting the Common Shares, other than the actions described above, which, in the reasonable opinion of the directors of the Corporation, would materially affect the rights of the holders of Subscription Receipts and/or the rights attached to the Subscription Receipts, then the number of Common Shares which are to be received pursuant to the Subscription Receipts shall be adjusted in such manner, if any, and at such time as the directors of the Corporation may, in their discretion, reasonably determine to be equitable to the holders of Subscription Receipts in such circumstances. The adjustments provided for in this paragraph are cumulative and shall apply to successive subdivisions, consolidations, changes, distributions, issues or other events resulting in any adjustment.

Under the Subscription Receipt Agreement, purchasers of Subscription Receipts will have a contractual right of rescission entitling the purchaser to receive the amount paid for the Subscription Receipts upon surrender of the Subscription Receipts or the Common Shares, as applicable, if the Prospectus and any amendment contains a misrepresentation, as such term is defined in the *Securities Act* (Ontario), provided such remedy for rescission is exercised within 180 days of the Closing Date.

Subject to applicable law, the Corporation will be entitled to purchase the Subscription Receipts in the open market or by private agreement or otherwise.

Subscriptions for the Subscription Receipts will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the closing of the Offering will take place on or about March 15, 2007, or such other date as may be agreed upon by the Corporation and the Underwriters, but not later than April 18, 2007 (the ''Closing Date''). The Subscription Receipts will be issued in ''book entry only'' form and must be purchased or transferred through a registered dealer who is a CDS participant (a ''CDS Participant''). The Corporation will cause a global certificate or certificates representing newly issued Subscription Receipts to be delivered to and registered in the name of CDS or its nominee. All rights of Subscription Receipt holders must be exercised through, and all payments or other money to which such holders are entitled will be made or delivered by, CDS or the CDS Participant through which the holders hold such Subscription Receipts. Each person who acquires Subscription Receipts will receive only a customer confirmation of purchase from the registered dealer from or through which the Subscription Receipts are acquired in accordance with the practices and procedures of that registered dealer. The practices of registered dealers may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS is responsible for establishing and maintaining book entry accounts for its CDS Participants having interests in the Subscription Receipts.

The Subscription Receipt Agreement provides for modifications and alternations to the Subscription Receipts issued thereunder by way of an extraordinary resolution. The term ''extraordinary resolution'' is defined in the Subscription Receipt Agreement to mean, in effect, a resolution proposed at a meeting of holders of Subscription Receipts duly convened for that purpose and held in accordance with the Subscription Receipt Agreement at which there are present in person or by proxy at least two holders of Subscription Receipts entitled to receive more than 25% of the aggregate number of Common Shares issuable upon the exchange of the Subscription Receipts which could be received pursuant to all the then-outstanding Subscription Receipts and passed by the affirmative votes of holders of Subscription Receipts entitled to receive not less than 66⅔% of the aggregate number of such Common Shares which could be received pursuant to all the then-outstanding Subscription Receipts represented at the meeting and voted on the poll upon such resolution.

The holders of Subscription Receipts are not shareholders of the Corporation. Holders of Subscription Receipts are entitled only to receive Common Shares on the exchange of their Subscription Receipts and an amount equal to the dividends declared on the Common Shares by the Corporation, if any, for which record dates have occurred during the period from the Closing Date to the date of issuance of the Common Shares in respect of the Subscription Receipts, or to require the Corporation to purchase the Subscription Receipts at the issue price and to be paid a *pro rata* share of interest earned or income generated thereon as described above.

CHANGES IN SHARE AND LOAN CAPITAL STRUCTURE

The following describes the changes in the share and loan capital structure of Fortis since September 30, 2006:

- During the period from October 1, 2006 up to and including March 6, 2007, Fortis issued an aggregate of 531,345 Common Shares pursuant to the Corporation's Consumer Share Purchase Plan, Dividend Reinvestment Plan, Employee Share Purchase Plan and upon the exercise of options granted pursuant to the 2002 Stock Option Plan, the Executive Stock Option Plan and the Director Stock Option Plan for aggregate consideration of approximately $10.2 million.

- On October 30, 2006, Fortis made a draw down of $20.0 million under its credit facilities for the purpose of funding the acquisition by Fortis Properties of four hotels located in Alberta and British Columbia. See ''Recent Developments''.

- On November 7, 2006, Fortis made a draw down under its credit facilities of an amount of US$48.6 million for the purpose of funding, on an interim basis, the acquisition of approximately 16% of the outstanding Class A Ordinary Shares of Caribbean Utilities. See ''Recent Developments''.

- On November 7, 2006, Fortis issued, by way of private placement, US$40 million aggregate principal amount of Debentures. The Debentures bear interest at an annual rate of 5.5% and mature on November 7, 2016. The Debentures may be redeemed by Fortis at any time on or after November 7, 2011 and are convertible into Common Shares at the option of the holder at any time prior to their maturity at US$29.11 per share. The Debentures are subordinated to all other indebtedness of Fortis, other than subordinated indebtedness ranking equally with the Debentures. On November 7, 2006, Fortis repaid US$40 million owing under its credit facilities from the proceeds of the private placement.

- On January 3, 2007, FortisAlberta issued $110 million aggregate principal amount of senior unsecured debentures bearing interest at a rate of 4.99% per annum, payable semi-annually, due January 2047. The proceeds of the offering were primarily used to repay indebtedness under a credit facility.

- On January 18, 2007, the Corporation completed the public offering of 5,170,000 Common Shares at a price of $29.00 per share for gross proceeds of $149,930,000. As a result, shareholders' equity in the Corporation increased by approximately $145.6 million, being the gross proceeds of the offering net of tax-effected issue costs, to a total of $1.55 billion. Fortis used a portion of the proceeds of this offering to repay approximately $84.5 million owing under its credit facilities.

USE OF PROCEEDS

The proceeds to the Corporation from the Offering, after deducting the fee payable to the Underwriters and estimated expenses of the Offering, are expected to be $959,710,000, assuming no exercise of the Over-Allotment Option. If the Over-Allotment Option is exercised in full, the estimated proceeds of the Offering, after deducting the fee payable to the Underwriters and estimated expenses of the Offering, are expected to be $1,103,854,000.

The net proceeds of the Offering, together with funds to be advanced pursuant to the Credit Facilities, will be used to finance the Cash Purchase Price for the Acquisition. See ''Financing of the Acquisition'' and ''Acquisition Agreement''. The gross proceeds from the sale of the Subscription Receipts will be held in escrow pending the satisfaction of the Release Conditions. See ''Details of the Offering''.

PLAN OF DISTRIBUTION

Pursuant to an underwriting agreement dated February 27, 2007 (the ''Underwriting Agreement'') between Fortis and the Underwriters, Fortis has agreed to issue and sell, and the Underwriters have agreed to purchase, as principals, on the Closing Date, 38,500,000 Subscription Receipts offered hereby at the Offering Price of $26.00 per Subscription Receipt, subject to compliance with all the necessary legal requirements and to the conditions contained in the Underwriting Agreement. The Offering Price and other terms of the Offering were determined by negotiation between the Corporation and the Underwriters.

Pursuant to the Underwriting Agreement, the Corporation has granted the Underwriters an over-allotment option (the ''Over-Allotment Option''), exercisable at any time until 30 days following the closing of the Offering, to purchase up to an additional 5,775,000 Subscription Receipts at the Offering Price. The Over-Allotment Option is exercisable in whole or in part only for the purpose of covering over-allotments, if any. This Prospectus also qualifies the grant of the Over-Allotment Option and the distribution of the securities issuable on the exercise of the Over-Allotment Option.

The Underwriting Agreement provides that the Underwriters will be paid a fee of $40,040,000 (assuming no exercise of the Over-Allotment Option) ($1.04 per Subscription Receipt) in consideration for its services in connection with the Offering. One-half of the Underwriters' fee in respect of the Offering is payable on the Closing Date and the other half of the Underwriters' fee is payable only if the Release Conditions have been satisfied prior to the Termination Time and the required notice has been delivered to the Escrow Agent.

Pursuant to rules and policy statements of certain Canadian securities regulators, the Underwriters may not, at any time during the period ending on the date the selling process for the Subscription Receipts ends and all stabilization arrangements relating to the Subscription Receipts are terminated, bid for or purchase Subscription Receipts or Common Shares. The foregoing restrictions are subject to certain exceptions including (a) a bid for or purchase of Subscription Receipts or Common Shares if the bid or purchase is made through the facilities of the TSX, in accordance with the Universal Market Integrity Rules of Market Regulation Services Inc., (b) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriter, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period, and (c) a bid or purchase to cover a short position entered into prior to the commencement of a prescribed restricted period. The Underwriters may engage in market stabilization or market balancing activities on the TSX where the bid for or purchase of the Subscription Receipts or the Common Shares is for the purpose of maintaining a fair and orderly market in the Subscription Receipts or Common Shares, subject to price limitations applicable to such bids or purchases. Such transactions, if commenced, may be discontinued at any time.

The Subscription Receipts and the Common Shares for which such Subscription Receipts may be exchanged have not been, and will not be, registered under the United States *Securities Act of 1933*, as amended (the ''1933 Act'') or any state securities laws and, subject to certain exceptions, may not be offered, or delivered, directly or indirectly, or sold in the United States except in certain transactions exempt from the registration requirements of the 1933 Act and in compliance with any applicable state securities laws. The Underwriters have agreed that they will not offer or sell the Subscription Receipts within the United States, its territories, its possessions and other areas subject to its jurisdiction or to, or for the account or benefit of, a ''U.S. person'' (as defined in Regulation S under the 1933 Act), except in accordance with the Underwriting Agreement pursuant to an exemption from the registration requirements of the 1933 Act provided by Rule 144A thereunder and in compliance with applicable state securities laws. In addition, until 40 days after the commencement of the Offering, an offer or sale of Subscription Receipts or Common Shares within the United States by any dealer (whether or not participating in the Offering) may violate the registration requirements of the 1933 Act if such offer is made otherwise than in reliance on Rule 144A.

The obligations of the Underwriters under the Underwriting Agreement are several and may be terminated at their discretion in certain circumstances, including upon the occurrence of certain stated events. The Underwriters are, however, obligated to take up and pay for all of the Subscription Receipts if any are purchased under the Underwriting Agreement. Under the terms of the Underwriting Agreement, the Underwriters may be entitled to indemnification by the Corporation against certain liabilities, including liabilities for misrepresentation in the Prospectus.

CIBCWM is an affiliate of a Canadian chartered bank that has agreed to extend credit facilities to the Corporation in connection with financing the Acquisition. CIBCWM is also acting as financial advisor to Fortis in connection with the Acquisition and receiving a fee therefor. In addition, each of CIBCWM, Scotia Capital, TD Securities, BMO Nesbitt Burns, RBCDS, NB Financial and HSBC Securities is a subsidiary of a Canadian chartered bank that has, either solely or as a member of a syndicate of financial institutions, extended credit facilities to the Corporation and/or its subsidiaries (the ''Existing Facilities''). Consequently, the Corporation may be considered a ''connected issuer'' of these Underwriters within the meaning of applicable securities legislation. None of these Underwriters will receive any direct benefit from the Offering other than the underwriting commission relating to the Offering. The decision to distribute the Subscription Receipts hereunder and the determination of the terms of the Offering were made through negotiation between the Corporation and the Underwriters. No bank had any involvement in such decision or determination. The proceeds of the Offering will be used to finance the Cash Purchase Price for the Acquisition and will not be used to repay the Existing Facilities. As at January 31, 2007, an aggregate of approximately $338 million was outstanding under the Existing Facilities. Fortis and/or its subsidiaries are in compliance with their respective obligations under the Existing Facilities. Since the execution of the Existing Facilities, no breach thereunder has been waived by the lenders thereunder. See ''Use of Proceeds''.

The TSX has conditionally approved the listing of the Subscription Receipts, as well as the Common Shares issuable on the exchange of the Subscription Receipts. Listing is subject to the Corporation fulfilling all of the requirements of the TSX on or before June 3, 2007.

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Davies Ward Phillips & Vineberg LLP, counsel to the Corporation, and Stikeman Elliott LLP, counsel to the Underwriters, the following is a general summary of the principal Canadian federal income tax considerations generally applicable to a holder who acquires Subscription Receipts pursuant to the Offering who, within the meaning of the *Income Tax Act* (Canada) (the ''Tax Act''), and at all relevant times, is or is deemed to be resident in Canada, deals at arm's length with, and is not affiliated with, the Corporation and holds or will hold the Subscription Receipts and any Common Shares as capital property. Generally, the Subscription Receipts and the Common Shares will be considered to be capital property to a holder provided the holder does not hold the Subscription Receipts and the Common Shares in the course of carrying on a business and has not acquired them in a transaction or transactions considered to be an adventure in the nature of trade. Certain holders whose Common Shares might not otherwise qualify as capital property may, in certain circumstances, make the irrevocable election under subsection 39(4) of the Tax Act to have their Common Shares and every ''Canadian security'' (as defined in the Tax Act) owned by such holder in the taxation year of the election, and in all subsequent years, deemed to be capital property.

The Tax Act contains certain provisions (the ''Mark-to-Market Rules'') relating to securities held by certain financial institutions, registered securities dealers and corporations controlled by one or more of the foregoing. This summary does not take into account the Mark-to-Market Rules and taxpayers that are ''financial institutions'' as defined for the purpose of the Mark-to-Market Rules should consult their tax advisors. This summary is not applicable to a purchaser that is a ''specified financial institution'' or to a purchaser an interest in which is a tax shelter investment, as defined in the Tax Act. Such purchasers should consult their own tax advisors.

This summary is based upon the provisions of the Tax Act and regulations thereunder (the ''Regulations'') in force as at the date hereof, all specific proposals (the ''Tax Proposals'') to amend the Tax Act or Regulations that have been publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof and counsel's understanding of the current published administrative practices of the Canada Revenue Agency. This summary does not otherwise take into account or anticipate any changes in applicable law, whether by legislative, governmental or judicial decision or action, nor does it take into account provincial, territorial or foreign tax laws or considerations, which might differ significantly from those discussed herein.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular holder. This summary is not exhaustive of all possible income tax considerations under the Tax Act that may affect a holder. The income tax consequences of acquiring and disposing of Subscription Receipts and Common Shares will vary depending on a number of facts, including the legal status of the holder as an individual, corporation, trust or partnership. Accordingly, prospective holders of Subscription Receipts and Common Shares should consult their own tax advisors with respect to their particular circumstances and the tax consequences to them of holding and disposing of Subscription Receipts and Common Shares.

Exchange of Subscription Receipts

No gain or loss will be realized by a holder on the exchange of Subscription Receipts for Common Shares.

The cost of a Common Share issued to a holder of a Subscription Receipt acquired pursuant to the Offering will be equal to the cost of the Subscription Receipt to the holder. The adjusted cost base to the holder of Common Shares so acquired will be determined by averaging the cost of such Common Shares with the adjusted cost base of all other Common Shares owned at that time by the holder as capital property.

Termination of Subscription Receipts

As described above under ''Details of the Offering'', in the event that the Release Conditions are not satisfied or if the Acquisition Agreement is terminated prior to the Termination Time, holders of Subscription Receipts will be entitled to receive from the Escrow Agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned or income generated thereon. In that event, the amount of such interest or income received or receivable by a holder of Subscription Receipts (depending on the method regularly followed by the holder in computing income) must be included in the income of the holder.

Payment of Dividend Equivalent

As described above under ''Details of the Offering'', if Common Shares are issued in exchange for Subscription Receipts, and if dividends have been declared on the Common Shares of the Corporation to holders of record on a date during the period from the Closing Date to the date of such issuance of Common Shares, the Corporation will make a cash payment to the holders of Subscription Receipts in respect of each Subscription Receipt in an amount equal to the per share amount of such dividend. The equivalent to dividend amount, if any, paid to a holder of Subscription Receipts by the Corporation must be included in the income of the holder. Any amount so included will be taxed as ordinary income and not as a dividend and, as such, will not be subject to the gross-up and dividend tax credit rules described below.

Other Dispositions of Subscription Receipts

A disposition or deemed disposition by a holder of a Subscription Receipt, other than on the exchange of a Subscription Receipt for a Common Share or a disposition of the Subscription Receipt to the Corporation in the event the Release Conditions are not satisfied or if the Acquisition Agreement is terminated prior to the Termination Time, will generally result in the holder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition exceed (or are less than) the aggregate of the holder's adjusted cost base thereof and any reasonable costs of disposition.

Dividends on Common Shares

Dividends received on Common Shares by a holder who is an individual will be included in the individual's income and will be subject to the gross-up and dividend tax credit rules normally applicable to taxable dividends received from taxable Canadian corporations, including the enhanced gross-up and dividend tax credit for ''eligible dividends'' paid after 2005. A dividend will be eligible for the enhanced gross-up and dividend tax credit if the paying corporation designates the dividend as an eligible dividend. There may be limitations on the ability of a corporation to designate dividends as eligible dividends. The Corporation has advised counsel that it intends to designate all dividends paid on the Common Shares as eligible dividends for these purposes. Taxable dividends received by an individual may give rise to alternative minimum tax under the Tax Act, depending on the individual's circumstances.

Dividends received on Common Shares by a holder that is a corporation will be included in income and normally will be deductible in computing such corporation's taxable income. However, the Tax Act will generally impose a 33⅓% refundable Part IV tax on such dividends received by a corporation that was, at any time in the taxation year in which such dividends were received, a ''private corporation'' as defined in the Tax Act, or a corporation resident in Canada that is controlled by or for the benefit of an individual (other than a trust) or a related group of individuals (other than trusts), to the extent that such dividends are deductible in computing the corporation's taxable income.

Disposition of Common Shares

In general, a disposition or a deemed disposition of a Common Share will give rise to a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition of the Common Share, net of any reasonable costs of disposition, exceed (or are less than) the adjusted cost base to the holder of the Common Share immediately before the disposition.

Tax Treatment of Capital Gains and Losses

Generally, one-half of any capital gain realized by a holder in a taxation year will be included in computing the holder's income in such year. One-half of any capital loss realized by a holder in a taxation year normally may be deducted as an allowable capital loss by the holder against taxable capital gains realized by the holder in the year. Any allowable capital loss not deductible in the year it is realized generally may be carried back and deducted against taxable capital gains in any of the three preceding years or carried forward and deducted against taxable capital gains in any subsequent year (in accordance with the rules contained in the Tax Act). Capital gains realized by an individual will be relevant in computing possible liability for the alternative minimum tax.

The amount of any capital loss realized on the disposition or deemed disposition of a Common Share by a holder that is a corporation may be reduced by the amount of dividends received by the holder on the Common Share to the extent and in the circumstances prescribed by the Tax Act. Similar rules may apply where a corporation is a member of a partnership or a beneficiary of a trust that owns Common Shares and where a trust is a member of a partnership that owns Common Shares or a partnership or trust is a beneficiary of a trust that owns Common Shares. Holders to whom these rules may be relevant should consult their own tax advisors.

Additional Refundable Tax

A holder that is a ''Canadian-controlled private corporation'' (as defined in the Tax Act) may be liable to pay an additional refundable tax of 6⅔% on certain investment income, including amounts in respect of taxable capital gains and interest (but not dividends deductible in computing taxable income).

RISK FACTORS

An investment in the Subscription Receipts offered hereby and the Common Shares issuable upon the exchange thereof involves certain risks in addition to those described in the Management Discussion and Analysis of financial condition and results of operations contained in the Corporation's annual information form dated March 29, 2006 incorporated by reference herein. Before investing, prospective purchasers of Subscription Receipts should carefully consider, in light of their own financial circumstances, the factors set out below, as well as the other information contained or incorporated by reference in the Prospectus.

Regulation

The regulated operations of Terasen Gas are subject to the normal uncertainties faced by regulated companies. These uncertainties include the approval by the BCUC of customer rates which permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair rate of return on rate base. Upgrades of existing facilities and the addition of new facilities require the approval of the BCUC. There is no assurance that capital projects perceived as required by the management of Terasen Gas will be approved or that conditions to such approval will not be imposed. Capital cost overruns relative to approvals granted might not be recoverable. The ability of Terasen Gas to recover the actual costs of providing services and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process. Fair regulatory treatment by the BCUC that allows Terasen Gas the opportunity to earn a risk-adjusted ROE comparable to that available on alternative, similar investments is essential for maintaining service quality, as well as for ongoing capital attraction and growth.

The ROEs of Terasen Gas are determined annually by a formula based upon a forecast of long-term interest rates. The ability of Terasen Gas to earn the approved ROEs depends on the accuracy of the forecast for the test year. Actual required ROEs may differ from approved ROEs based on forecast long-term interest rates.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through public hearing processes. There can be no assurance that the rate orders issued will permit Terasen Gas to recover all costs actually incurred and to earn the allowed rate of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by Terasen Gas, the undertaking or timing of proposed expansion projects, the issue and sale of securities, ratings assigned by rating agencies, and other matters which may, in turn, negatively impact Terasen Gas' results of operations or financial position, as well as those of the Corporation.

The TGI Settlement includes incentive mechanisms that provide TGI with an opportunity to earn rates of return in excess of the allowed ROEs determined by the BCUC. While TGI has applied to extend the TGI Settlement to 2009, there is no certainty as to whether this application will be approved, whether and how the terms may be modified, or what the terms of an extended, or new, settlement might be.

Traditionally, British Columbia's regulatory framework was generally based on traditional cost of service methodologies for designing and setting rates. Since 1996, however, incentive-based regulation has been used in the rate setting process. Although Fortis considers the regulatory frameworks in British Columbia to be fair and balanced, uncertainties do exist.

Forecasting Accuracy

Through the forecasting process, it is intended that any changes in cost of service, regardless of whether they are caused by inflation or by level of business activity, would be reflected in new rates approved for that fiscal year based on the anticipated distribution volume. However, as rates are established in advance, based on anticipated distribution volume by class of customer, forecasting accuracy is a risk. Forecasts are also made for the future cost of capital, including the yield rate for long-term Canada Bonds used in the determination of the ROE.

Asset Maintenance

The asset base for Terasen Gas requires maintenance, improvement and expansion. The utility could experience service disruptions and increased costs if it is unable to maintain and replace its assets. The failure to carry out capital expenditure programs could have a material adverse effect on Terasen Gas. Large capital projects can proceed only with the approval of the BCUC. If actual costs exceed the costs forecast in obtaining the approval, it is uncertain as to whether any cost overruns will be approved and recovered.

Operational Risks

The business of Terasen Gas is exposed to various operational risks, such as pipeline leaks, accidental damage to or fatigue cracks in mains and service lines, corrosion in pipes, pipeline or equipment failure, other issues that can lead to outages and leaks, and any other accidents involving natural gas, which could result in significant operational and environmental liability. The facilities of Terasen Gas are also exposed to the effects of severe weather conditions and other acts of nature. In addition, many of these facilities are located in remote areas, which makes access for repair of damage due to weather conditions and other acts of nature difficult. Terasen Gas operates facilities in a terrain with a risk of loss or damage from earthquakes, forest fires, floods, washouts, landslides, avalanches and similar acts of nature. Terasen Gas has insurance which provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the BCUC for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the BCUC would approve any such application. Losses resulting from any operational accidents or failures or natural disasters could substantially exceed insurance coverage and actual recovery from increased rates approved by the BCUC. Furthermore, Terasen Gas could be subject to claims from its customers for damages caused by the failure to transmit or distribute gas to them in accordance with its contractual obligations. Thus, any major damage to Terasen Gas' facilities could result in lost revenues, repair costs and customer claims that are substantial in amount, which amount could have a material adverse effect on Terasen Gas.

Natural Gas Prices

Prior to 2000, natural gas consistently had a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, with the increasing price of natural gas, the price of electricity for residential customers in British Columbia is now only marginally higher than the comparable price for natural gas. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future.

If natural gas pricing becomes uncompetitive with electricity pricing, Terasen Gas' ability to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover Terasen Gas' cost of service in rates charged to customers.

The ability of Terasen Gas to add new customers and sales volumes could also be affected by lower prices of other competitive energy sources as some commercial and industrial customers have the ability to switch to an alternative fuel.

Terasen Gas employs a number of tools to reduce its exposure to natural gas price volatility. These include purchasing gas for storage and adopting hedging strategies to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive with electricity rates. Activities related to the hedging of gas prices are currently approved by the BCUC and gains or losses effectively accrue entirely to customers. Future BCUC determinations could materially impact the ability of Terasen Gas to recover the future cost of the natural gas it delivers to its customers.

Weather and Seasonality

Weather during the year has a significant impact on distribution volume as a major portion of the gas distributed by Terasen Gas is ultimately used for space heating. Because of natural gas consumption patterns, the natural gas distribution operations of Terasen Gas normally generate quarterly earnings that vary by season. Typically, higher net earnings are experienced in the first and fourth quarters, but are offset by net losses in the second and third quarters. See ''The Acquired Business — Regulation''.

Risks Related to Terasen Gas (Vancouver Island) Inc.

TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet its current cost of service and recover revenue deficiencies from prior years. Recovery of the accumulated deficit puts gas at a cost disadvantage to electricity.

To assist with competitive rates during franchise development, the VINGPA provides royalty revenues from the provincial government which currently cover approximately 20% of the current cost of service. These revenues are due to expire at the end of 2011, after which TGVI's customers will be required to absorb the full commodity cost of gas and the recovery of any remaining accumulated deficit. When the VINGPA expires in 2011, the $75 million non-interest-bearing senior government debt which is currently treated as a government contribution against rate base will become repayable. As this debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates making gas less competitive with electricity on Vancouver Island.

Industrial load accounts for more than 65% of the system's throughput for which approximately two thirds is contracted on a year-to-year basis with no long-term commitment. A loss of industrial customers will increase the cost of service to be recovered from residential and commercial customers which may impact the competitiveness of rates.

While the BCUC has approved a rate-setting mechanism for TGVI whereby customer rates are set at levels in excess of TGVI's cost of service to recover amortization of the RDDA, the amount of recovery is limited by the price of competitive alternative fuels. Significant RDDA amortization was recovered in both 2005 and 2006. However, RDDA recovery is sensitive to the relative pricing of natural gas and electricity in TGVI's service area, as well as to margin generated under TGVI's firm transportation agreements discussed below. There is no certainty that TGVI will be able to charge rates that will be sufficient to fully recover the RDDA prior to the expiry of the provincial royalty payments at the end of 2011. Failure by TGVI to recover the RDDA by 2011 may result in an increase in the cost of service.

Government Permits

The acquisition, ownership and operation of gas businesses and assets require numerous permits, approvals and certificates from federal, provincial and local government agencies. Terasen Gas may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval or if Terasen Gas fails to maintain or obtain any required approval or fails to comply with any applicable law or regulation, or condition of approval, the operation of its assets and its distribution of gas could be prevented or become subject to additional costs, any of which could have a material adverse effect on Terasen Gas.

Impact of Changes in Economic Conditions

New customer additions at Terasen Gas are typically a result of population growth and new housing starts, which are affected by the state of the British Columbia economy. Terasen Gas is also affected by changes in trends in housing starts from single-family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. While new housing starts have increased in British Columbia in 2006, growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. In addition, more efficient building construction and consistent customer conservation efforts place downward pressure on annual average consumption of natural gas. Prevailing economic conditions also impact sales and transportation service to large-volume commercial and industrial customers.

Natural Gas Supply

Terasen Gas is dependent on a limited selection of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas where the majority of Terasen Gas' natural gas distribution customers are located. As a result, regional market prices have been higher from time to time than prices elsewhere in North America as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia.

In addition, Terasen Gas is critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption on the Spectra Pipeline System, Terasen Gas' residential customers could experience outages, thereby affecting revenues and incurring costs to safely relight customers.

Access to Capital and Credit Ratings

In order to meet the capital investment and debt repayment requirements of its business, Terasen Gas must have reliable access to sufficient and cost-effective capital. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the regulatory environment in British Columbia, the results of operations and financial position of Terasen Gas, conditions in the capital and bank credit markets, the ratings assigned by rating agencies and general economic conditions. There can be no assurance that sufficient capital will be available on acceptable terms to fund such capital expenditures and to repay existing debt.

An inability to maintain an investment-grade credit rating could materially adversely impact Terasen Gas' access to debt financing. In addition, a downgrade of Terasen Gas below investment grade by any of the major credit rating agencies could trigger margin calls and other cash requirements under Terasen Gas' gas purchase and commodity derivative contracts.

Interest Rates

Terasen Gas is exposed to the interest rate risks associated with floating rate debt. Terasen Gas has hedging programs in place to reduce its interest rate risks. The allowed ROEs for TGI and TGVI are determined by formulae that result in lower allowed ROEs if long-term Canada Bond yields decline.

Counterparty Credit Risk

Terasen Gas is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Terasen Gas is also exposed to significant credit risk on physical off-system sales. Because it deals with high credit quality institutions in accordance with established credit approval practices, Terasen Gas does not expect any counterparties to fail to meet their obligations.

Potential Undisclosed Liabilities Associated with the Acquisition

In connection with the Acquisition, there may be liabilities that the Corporation failed to discover or was unable to quantify in its due diligence which it conducted prior to the execution of the Acquisition Agreement and the Corporation may not be indemnified for some or all of these liabilities. The discovery or quantification of any material liabilities could have a material adverse effect on the Corporation's business, financial condition or future prospects. In addition, the Acquisition Agreement limits the amount for which the Corporation is indemnified. See ''Acquisition Agreement — Indemnities''.

Labour Relations

The organized employees of TGI and TGVI are members of labour unions which have entered into collective bargaining agreements with TGI. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by TGI, TGVI and TGWI (which depends on TGI for its customer, management and operation services). TGI considers its relationships with its labour unions to be satisfactory, but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain, or to renew the collective bargaining agreements on acceptable terms, could result in increased labour costs or service interruptions arising from labour disputes for TGI that are not provided for in approved orders, which could have an adverse effect on the results of operations, cash flow and net income of Terasen Gas.

Underinsured and Uninsured Losses

Fortis and Terasen Gas maintain at all times insurance coverage in respect of potential liabilities and the accidental loss of value of certain of their assets from risks, in amounts, with such insurers, as is considered appropriate, taking into account all relevant factors including the practices of owners of similar assets and operations. It is anticipated that such insurance coverage will be maintained. However, not all risks are covered by insurance and no assurance can be given that insurance will be consistently available or will be consistently available on economically feasible terms or that the amounts of insurance will be sufficient to cover losses or claims that may occur involving the assets or operations of Fortis or Terasen Gas.

Environmental Matters

Terasen Gas is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety. Potential environmental damage and costs could arise due to a severe weather event or a major equipment failure. However, there can be no assurance that such costs will be recoverable and, if substantial, unrecovered costs may have a material effect on the business, results of operations and prospects of Terasen Gas.

Terasen Gas is exposed to environmental risks that property owners in British Columbia generally face. These risks include the responsibility of any property owner for the site remediation of any properties determined to be contaminated, whether or not such contamination was actually caused by the owner. Most of Terasen Gas' distribution and transmission facilities have been in place for many years with no apparent adverse environmental impact. However, as facilities are upgraded and as new facilities are added, environmental assessments and regulatory approvals will be required in the ordinary course.

Applicable environmental and safety laws make owners, operators and persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval for the discharge of contaminants causing an adverse effect. Terasen Gas has not been notified of any such regulatory action in regard to its operation or occupation of its facilities. However, it is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety regulations could also lead to significant increases in costs to Terasen Gas.

First Nations' Lands

Terasen Gas provides service to customers on First Nations reserves in British Columbia and maintains gas distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Government of British Columbia is underway in British Columbia but the basis upon which settlements might be reached in Terasen Gas' service area is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as Terasen Gas. However, there can be no certainty that the settlement process will not adversely affect the business of Terasen Gas.

Results of Operations and Financing Risks

Management of the Corporation believes, based on its expectations as to the Corporation's future performance (which reflects, among other things, the completion of the Acquisition), that the cash flow from its operations and funds available to it under its credit facilities will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Corporation. As such, no assurance can be given that management's expectations as to future performance will be realized. In addition, management's expectations as to the Corporation's future performance reflect the current state of its information about Terasen Gas and its operations and there can be no assurance that such information is correct and complete in all material respects.

Management of Expanding Operations

As a result of the Acquisition, significant demands will be placed on the Corporation's managerial, operational and financial personnel and systems. No assurance can be given that the Corporation's systems, procedures and controls will be adequate to support the expansion of the Corporation's operations resulting from the Acquisition. The Corporation's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

Realization of Acquisition Benefits

As described in ''The Acquisition — Acquisition Rationale'', the Corporation believes that the Acquisition will provide benefits to Fortis. However, there is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation.

Subscription Receipt Structure

The Subscription Receipts will be automatically exchanged for Common Shares upon the satisfaction of the Release Conditions. The Corporation may, in its sole discretion, waive certain closing conditions in its favour in the Acquisition Agreement or agree with the Vendor to amend the Acquisition Agreement and consummate the Acquisition on terms that may be substantially different from those contemplated in this Prospectus. As a result, the expected benefits of the Acquisition may not be fully realized. See ''Acquisition Agreement''. There can be no assurance that the Release Conditions will be satisfied on or prior to the Termination Time. Until the Release Conditions are satisfied and the Common Shares are delivered pursuant to the Subscription Receipt Agreement, holders of Subscription Receipts have the rights as described under ''Details of the Offering — Subscription Receipts''.

Market for Securities

There is currently no market through which the Subscription Receipts may be sold. There can be no assurance that an active trading market will develop for the Subscription Receipts after the Offering or, if developed, that such a market will be sustained at the price level of the Offering. The TSX has conditionally approved the listing of the Subscription Receipts, as well as the Common Shares issuable on the exchange of the Subscription Receipts. Listing is subject to the Corporation fulfilling all of the requirements of the TSX on or before June 3, 2007.

AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants (''Ernst & Young''), The Fortis Building, 7th Floor, 139 Water Street, St. John's, Newfoundland and Labrador, A1C 1B2. Ernst & Young report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Newfoundland.

The auditors of Terasen as at December 31, 2005 were KPMG LLP, Chartered Accountants (''KPMG''), of Vancouver, British Columbia. KPMG report that, as at March 31, 2006 and during the years ended December 31, 2005 and 2004 on which they reported, they were independent of Terasen within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of British Columbia.

LEGAL MATTERS

Certain legal matters relating to this Offering will be passed upon on behalf of the Corporation by Davies Ward Phillips & Vineberg LLP, Toronto and McInnes Cooper, St. John's and on behalf of the Underwriters by Stikeman Elliott LLP, Toronto. At the date hereof, partners and associates of each of Davies Ward Phillips & Vineberg LLP, McInnes Cooper and Stikeman Elliott LLP own beneficially, directly or indirectly, less than 1% of any securities of the Corporation or any associate or affiliate of the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Subscription Receipts is Computershare Trust Company of Canada in Toronto and Montréal.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal advisor.

GLOSSARY OF TERMS

In the Prospectus, unless the context otherwise requires, the following terms have the meanings set forth below.

''1933 Act'' means the United States *Securities Act of 1933*, as amended;

''Acquisition'' means the acquisition by Fortis of all of the issued and outstanding shares of Terasen;

''Acquisition Agreement'' means the acquisition agreement dated February 26, 2007 between Fortis, 3211953 Nova Scotia Company and Kinder Morgan;

''CDS'' means CDS Clearing and Depository Services Inc.;

''Closing Date'' means on or about March 15, 2007, or such other date as agreed to by the Corporation and the Underwriters, but not later than April 18, 2007;

''Corporation'' or **''Fortis''** means Fortis Inc.;

''Credit Facilities'' means the senior unsecured, non-revolving term credit facilities in the aggregate amount of $1.425 billion, consisting of a facility in the amount of $925 million and a facility in the amount of $500 million, to be extended to Fortis pursuant to a commitment letter dated February 26, 2007 from Canadian Imperial Bank of Commerce;

''CWP'' means CustomerWorks Limited Partnership;

''Escrow Agent'' means Computershare Trust Company of Canada or its successor as escrow agent under the Subscription Receipt Agreement;

''Escrowed Funds'' means the gross proceeds from the sale of the Subscription Receipts;

''Offering'' means the distribution of Subscription Receipts pursuant to the Prospectus;

''Release Conditions'' means the receipt by the Corporation of all regulatory and government approvals required to finalize the Acquisition, including that of the BCUC, and fulfillment or waiver of all other outstanding conditions precedent to closing the Acquisition as itemized in the Acquisition Agreement;

''ROE'' means return on equity;

''SEDAR'' means the Canadian System for Electronic Document Analysis and Retrieval;

''Subscription Receipt Agreement'' means the agreement dated as of the Closing Date among the Corporation, CIBC World Markets Inc. and the Escrow Agent governing the terms of the Subscription Receipts;

''Subscription Receipts'' means the subscription receipts of the Corporation offered hereby;

''Terasen'' means Terasen Inc.;

''Terasen Gas'' means, collectively, TGI, TGVI, TGWI and CWP;

''Termination Time'' means the earlier of 5:00 p.m. (Toronto time) on November 30, 2007 or the date on which the Acquisition Agreement is terminated;

''TGI'' means Terasen Gas Inc.;

''TGVI'' means Terasen Gas (Vancouver Island) Inc.;

''TGWI'' means Terasen Gas (Whistler) Inc.;

''TSX'' means the Toronto Stock Exchange;

''Underwriters'' means, collectively, CIBC World Markets Inc., Scotia Capital Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., National Bank Financial Inc., Canaccord Capital Corporation, Beacon Securities Limited and HSBC Securities (Canada) Inc.; and

''Underwriting Agreement'' means the underwriting agreement dated February 27, 2007, between the Corporation and the Underwriters relating to the sale of the Subscription Receipts offered under the Prospectus.

All dollar amounts in the Prospectus are expressed in Canadian dollars.

AUDITORS' CONSENT

We have read the short form prospectus of Fortis Inc. (the ''Corporation'') dated March 7, 2007 relating to the issue and sale of 38,500,000 subscription receipts of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference, in the above-mentioned prospectus, of our report to the shareholders of the Corporation on the consolidated balance sheets of the Corporation as at December 31, 2005 and 2004 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. Our report is dated January 27, 2006.

St. John's, Canada	(Signed) Ernst & Young LLP
March 7, 2007	Chartered Accountants

AUDITORS' CONSENT

We have read the short form prospectus of Fortis Inc. (the ''Corporation'') dated March 7, 2007 relating to the issue and sale of 38,500,000 subscription receipts of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use in the above-mentioned prospectus of our report to the shareholder of Terasen Inc. on the consolidated statements of financial position of Terasen Inc. as at December 31, 2005 and 2004 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. Our report is dated February 3, 2006, except as to note 19(b) which is as of March 2, 2006 and note 19(c) which is as of March 31, 2006.

Vancouver, Canada	(Signed) KPMG LLP
March 7, 2007	Chartered Accountants

INDEX TO FINANCIAL STATEMENTS

Terasen Inc.

Consolidated Financial Statements
Years ended December 31, 2005 and 2004

Together with Auditors' Report

AUDITORS' REPORT TO THE SHAREHOLDER

We have audited the consolidated statements of financial position of Terasen Inc. as at December 31, 2005 and 2004 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(Signed) KPMG LLP
Chartered Accountants

Vancouver, Canada
February 3, 2006, except as to note 19 (b) which is
as of March 2, 2006 and note 19 (c) which is
as of March 31, 2006

TERASEN INC.

CONSOLIDATED STATEMENTS OF EARNINGS

	Years ended December 31	
	2005	2004
		(Restated — notes 1(p) and 3)
	In millions of dollars	
Revenues		
Natural gas distribution	**$1,678.0**	$1,494.1
Petroleum transportation	**227.8**	225.5
Other activities	**46.7**	78.5
	1,952.5	1,798.1
Expenses		
Cost of natural gas	**1,063.7**	885.4
Cost of revenues from other activities	**28.9**	52.8
Operation and maintenance	**320.7**	274.7
Depreciation and amortization	**142.6**	144.5
Property and other taxes	**71.9**	69.9
	1,627.8	1,427.3
Operating Income	**324.7**	370.8
Financing costs (note 14)	**191.4**	175.6
Earnings before share of earnings of equity investments and income taxes	**133.3**	195.2
Equity earnings from Clean Energy net of disposition costs (note 4)	**2.5**	—
Share of earnings of Express System	**21.9**	15.0
Earnings before income taxes and discontinued operations	**157.7**	210.2
Income taxes (note 15)	**51.6**	63.7
Earnings before discontinued operations	**106.1**	146.5
Earnings (loss) from discontinued operations, net of income taxes (note 3)	**(4.9)**	3.3
NET EARNINGS	**$ 101.2**	$ 149.8

TERASEN INC.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Years ended December 31	
	2005	2004 (Restated — note 1(p))
	In millions of dollars	
Retained earnings, beginning of year	**$418.9**	$355.5
Net earnings	**101.2**	149.8
	520.1	505.3
Dividends on common shares	**95.1**	86.4
Retained earnings, end of year	**$425.0**	$418.9

TERASEN INC.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	In millions of dollars As at December 31	
	2005	2004 (Restated — note 1(p))
Assets		
Current assets		
Cash and short-term investments	**$ 79.4**	$ 20.0
Accounts receivable	**468.1**	348.6
Inventories of gas in storage and supplies	**205.7**	189.2
Prepaid expenses	**14.1**	9.5
Current portion of rate stabilization accounts (note 7)	**28.4**	27.1
Current assets held for sale (note 3)	**54.8**	—
	850.5	594.4
Property, plant and equipment (note 6)	**3,907.9**	3,892.5
Long-term investment	**238.3**	218.9
Goodwill	**76.4**	128.0
Rate stabilization accounts (note 7)	**48.3**	60.6
Other assets (note 8)	**84.8**	87.4
Long-lived assets held for sale (note 3)	**109.9**	—
	$5,316.1	$4,981.8
Liabilities and shareholder's equity		
Current liabilities		
Short-term notes	**$ 681.0**	$ 248.0
Accounts payable and accrued liabilities	**433.8**	365.7
Income and other taxes payable	**30.8**	36.4
Current portion of rate stabilization accounts (note 7)	**47.9**	27.6
Current portion of long-term debt (note 9)	**398.2**	416.7
Due to parent company	**0.4**	—
Current liabilities held for sale (note 3)	**24.5**	—
	1,616.6	1,094.4
Long-term debt (note 9)	**2,012.9**	2,291.6
Other long-term liabilities and deferred credits (note 10)	**168.5**	156.0
Future income taxes (note 15)	**88.7**	68.7
Long-term liabilities held for sale (note 3)	**13.7**	—
	3,900.4	3,610.7
Shareholder's equity		
Common shares (note 11)	**904.9**	883.4
Contributed surplus (note 12)	**137.5**	132.5
Retained earnings	**425.0**	418.9
Cumulative currency translation adjustment	**(0.7)**	(12.7)
	1,466.7	1,422.1
Less cost of common shares held by Terasen Pipelines (Trans Mountain) Inc.	**51.0**	51.0
	1,415.7	1,371.1
	$5,316.1	$4,981.8

Approved by the Board:

(Signed) JAMES M. STANFORD
Director

(Signed) DOUGLAS W.G. WHITEHEAD
Director

TERASEN INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	In millions of dollars 2005	2004
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$101.2**	$149.8
Adjustments for non-cash items		
Loss (earnings) from discontinued operations	**4.9**	(3.3)
Depreciation and amortization	**142.6**	144.5
Equity earnings from Clean Energy	**(2.5)**	—
Share of earnings from long-term investments, in excess of cash distributions	**(19.4)**	(14.3)
Future income taxes	**2.9**	(0.5)
Other	**18.7**	10.2
	248.4	286.4
Decrease in rate stabilization accounts	**10.1**	31.0
Discontinued operations — Water and Utility Services	**5.2**	3.3
Changes in non-cash working capital	**(68.3)**	14.7
	195.4	335.4
Investing activities		
Property, plant and equipment	**(214.7)**	(154.4)
Acquisition of water and utility services businesses (note 4)	**—**	(57.9)
Proceeds on sale of Clean Energy (note 4)	**43.0**	—
Discontinued operations — Water and Utility Services	**(36.8)**	—
Proceeds on sale of other property, plant and equipment	**—**	0.9
Proceeds on sale of natural gas distribution assets (note 10)	**7.2**	64.6
Other assets and deferred credits	**(11.2)**	(13.4)
	(212.5)	(160.2)
Financing activities		
Increase (decrease) in short-term notes	**433.0**	(305.9)
Increase in long-term debt	**601.5**	339.1
Reduction of long-term debt	**(884.9)**	(118.2)
Advances from parent company	**0.4**	—
Discontinued operations — Water and Utility Services	**0.7**	—
Issue of common shares, net of issue costs (note 11)	**20.9**	14.7
Dividends on common shares	**(95.1)**	(86.4)
	76.5	(156.7)
Net increase in cash	**59.4**	18.5
Cash at beginning of year	**20.0**	1.5
Cash at end of year	**$ 79.4**	$ 20.0
Supplemental cash flow information		
Interest paid in the year	**$187.6**	$162.7
Income taxes paid in the year	**48.4**	78.1
Non-cash transactions		
Mark to market on certain gas derivatives deferred in rate-stabilization accounts	**21.2**	—

Cash is defined as cash or bank indebtedness.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular amounts in millions of dollars, except where stated otherwise)
YEARS ENDED DECEMBER 31, 2005 AND 2004

Terasen Inc. (''Terasen'' or the ''Company'') provides energy transportation and utility asset management services. Terasen operates in three primary business segments which are separately managed to assess operational performance.

(a) Natural gas distribution operations involve the transmission and distribution of natural gas and propane for residential, commercial, institutional, and industrial customers in British Columbia. The operations are conducted through Terasen Gas Inc. (''Terasen Gas''), serving the Lower Mainland and interior of British Columbia, Terasen Gas (Vancouver Island) Inc. (''TGVI''), serving Vancouver Island and the Sunshine Coast, Terasen Gas (Whistler) Inc., and Terasen Gas (Squamish) Inc.

(b) Petroleum transportation operations are carried out through Terasen Pipelines (Trans Mountain) Inc. (''Trans Mountain''), which owns and operates a common carrier pipeline system for crude and refined petroleum products transported from Edmonton, Alberta to Vancouver, British Columbia and Washington State, Terasen Pipelines (Corridor) Inc. (''Corridor''), which owns a pipeline in northern Alberta transporting diluted bitumen, and the one-third owned entities Express Pipeline LP and Express US Holdings LP (''the Express System''). The Express System transports crude oil from Hardisty, Alberta, through the Rocky Mountain region of the United States and on to Wood River, Illinois.

(c) Water and utility services operations includes providing water and wastewater treatment services, water distribution and wastewater collection, meter reading, meter fleet management and installation services as well as product sales related to the water, sewer and irrigation markets. These operations are provided through Terasen Waterworks (Supply) Inc., Terasen Utility Services Inc., Terasen Utility Services (U.S.) Inc. (collectively ''Terasen Water and Utility Services''), and the Company's 50% interest in Fairbanks Sewer and Water Inc. (''FSW''). These operations have been reclassified to Discontinued Operations as described in Note 3.

(d) Other activities include international consulting activities, the Company's 30% interest in CustomerWorks LP (''CWLP''), corporate financing costs and administration charges, and the Company's 40% (2004 — 45%) interest in Clean Energy Fuels Corp. (''Clean Energy''), which was proportionately consolidated until the first quarter of 2005 and was then equity-accounted for until the investment was sold on October 31, 2005 (Note 4).

The Company operates in Canada and the United States, but at the present time the United States operations are not of sufficient size to be reportable as either operating or geographic segments.

On November 30, 2005, all of the shares of the Company were acquired by Kinder Morgan, Inc. (''KMI'') pursuant to a Combination Agreement dated as of August 1, 2005. The Company's shareholders were able to elect, for each Terasen share held, either (i) $35.75 in cash, (ii) 0.3331 shares of KMI common stock, or (iii) $23.25 in cash plus 0.1165 shares of KMI common stock. In the aggregate, approximately 12.5 million shares of KMI common stock was issued together with cash payments of approximately $2.49 billion to Terasen securityholders. The Company has charged to earnings after-tax costs of $42.9 million associated with the transaction in earnings in the year ended December 31, 2005, mainly from pre-tax investment banking costs of $14.7 million, severance and employee-related costs of $14.4 million, share option costs of $3.6 million as described in Note 12, and the write-off of approximately $15.3 million of income tax expense related to restricted tax loss carry-forwards.

1. SIGNIFICANT ACCOUNTING POLICIES

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses in the financial statements, as well as the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and reflect the following summary of significant accounting policies.

(a) BASIS OF PRESENTATION

The consolidated financial statements include the accounts of the Company, its subsidiaries, and its proportionate share of the accounts of jointly-controlled entities. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method.

Certain of the prior year comparative figures have been reclassified to conform with the current year's presentation.

(b) FOREIGN CURRENCY TRANSLATION

The Company translates its self-sustaining US dollar denominated water and utility service businesses' and Clean Energy's financial statements into Canadian dollars using the current rate method of foreign currency translation. Under this method, assets and liabilities are translated at the rate of exchange in effect at the balance sheet date, revenue and expense items are translated at average rates of exchange for the period, and the exchange gains and losses arising on the translation of the financial statements are recorded in the cumulative currency translation adjustment account in Shareholders' equity.

The Company's US-based petroleum transportation operations are integrated and are translated into Canadian dollars using the temporal method. Under this method, monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date, with the exception of certain long-term debt in the Express System, which is considered to be a hedge of

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

U.S. dollar denominated revenues in the Express System. Non-monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect on the dates the assets were acquired or liabilities assumed. Revenues and expenses are translated at the average rates of exchange prevailing during the month the transactions occurred. Under this method, exchange gains and losses on translation are reflected in income when incurred.

(c) REGULATION

The natural gas distribution companies are subject to the regulation of the British Columbia Utilities Commission (''the BCUC''), an independent regulatory authority. Both Terasen Gas and TGVI have multi-year agreements that will expire at the end of 2007. These multi-year agreements are cost-of-service based agreements with allowed rates of return on approved rate base set by the BCUC. For 2005, Terasen Gas's allowed rate of return was 9.03% and TGVI's allowed rate of return was 9.53%. The allowed rates of return are based on a notional debt-equity ratio of 67% debt and 33% equity for Terasen Gas and 65% debt and 35% equity for TGVI. The entities have annual review processes for rate approvals, and the allowed rates of return are reset annually unless directed differently by the BCUC.

The Trans Mountain and Express System operations are governed by contractual arrangements with shippers and are regulated in Canada by the National Energy Board and, in the United States, tariff matters are regulated by the Federal Energy Regulatory Commission. Both of these regulatory authorities are independent bodies. Trans Mountain has entered into a memorandum of understanding with shippers on a new five-year agreement which will expire at the end of 2010. The Express System has firm service agreements that extend until 2015.

Corridor's operations are governed by contractual arrangements with shippers and are subject to regulation by the Alberta Energy and Utilities Board (''the AEUB''), an independent regulatory authority. Corridor's rates are cost-of-service based and determined using formulas embedded in agreements with shippers.

FSW is regulated by the Regulatory Commission of Alaska, an independent regulatory authority. FSW has a cost-of-service based agreement with allowed rates of return set by the Regulatory Commission. FSW is currently operating on an interim rate basis while the Commission is hearing a new rate case.

Approximately 95% of the Company's operations are subject to rate regulation by independent regulatory agencies. These regulatory authorities exercise statutory authority over such matters as rates of return, construction and operation of facilities, accounting practices, rates and tolls, and contractual agreements with customers.

In order to recognize the economic effects of regulation, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non-regulated businesses.

The impacts of rate regulation on the Company's operations for the twelve months ending December 31, 2005 and as at December 31, 2005 are described in these Significant Accounting Policies, and in Note 6 ''Property, Plant and Equipment'', Note 7 ''Rate Stabilization Accounts'', Note 8 ''Other Assets'', Note 10 ''Other Long-Term Liabilities and Deferred Credits'', Note 13 ''Employee Benefit Plans'', Note 14 ''Financing Costs'', and Note 15 ''Income Taxes''.

(d) INVENTORIES

Inventories of gas in storage are valued at weighted-average cost. Supplies and other inventories are valued at the lower of cost and net realizable value.

(e) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures for system expansions, betterments and replacements, an allocation of overhead costs and an allowance for funds used during construction. When allowed by the regulators, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

Depreciation of regulated assets is recorded on a straight-line basis over their useful lives. Depreciation rates for regulated assets are approved by the respective regulator, and for non-regulated assets requires the use of management estimates of the useful lives of assets. Depreciation of non-regulated equipment is recorded using the declining balance method.

The cost of regulated depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation, as is any gain or loss incurred on disposal.

(f) IMPAIRMENT OF LONG-LIVED ASSETS

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

(g) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Company concurrently recognizes a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the life of the asset. The fair value of the asset retirement obligation is estimated using the expected cash

1. **SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)**

flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Changes in the obligation due to the passage of time are recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Company's natural gas distribution and petroleum transportation systems are not currently determinable, the Company has not recognized an asset retirement obligation as at December 31, 2005 and 2004. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates or tolls.

(h) RATE STABILIZATION ACCOUNTS

TGVI maintains a BCUC approved Revenue Deficiency Deferral Account (''RDDA'') to accumulate unrecovered costs of providing service to customers or to drawdown such costs where earnings exceed an allowed return as set by the BCUC. The RDDA has accumulated the allowed earnings in excess of achieved earnings prior to 2003 and is to be recovered through future rates. During the years ended December 31, 2005 and 2004, the RDDA has decreased as achieved earnings have exceeded the allowed return.

Terasen Gas is authorized by the BCUC to maintain rate stabilization accounts which mitigate the effect on its earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility. The Revenue Stabilization Adjustment Mechanism (''RSAM'') accumulates the margin impact of variations in the actual versus forecast volume use for residential and commercial customers.

In 2004, the Gas Cost Reconciliation Account (''GCRA''), which accumulates differences between actual natural gas costs and forecast natural gas costs as recovered in base rates, was replaced by the Commodity Cost Reconciliation Account (''CCRA'') and the Midstream Cost Reconciliation Account (''MCRA''). The two new accounts were approved by the BCUC to segregate costs that are allocable to all sales customers (MCRA) and all residential customers and certain commercial and industrial customers for whom Terasen Gas acquires gas supply (CCRA). TGVI has a Gas Cost Variance Account (''GCVA'') which mitigates the effect on its earnings of natural gas cost volatility. The GCVA is recoverable in rates from customers in TGVI's service areas in future periods.

All rate stabilization account balances for both TGVI and Terasen Gas are amortized and recovered through rates as approved by the BCUC.

(i) DEFERRED CHARGES

The Company defers certain costs which the regulatory authorities or contractual arrangements require or permit to be recovered through future rates or tolls. Deferred charges are amortized over various periods as approved by the regulator and depending on the nature of the costs.

Deferred charges include long-term debt issue costs which are amortized over the term of the related debt.

Deferred charges not subject to regulation relate to projects which are expected to benefit future periods and will be capitalized on completion, expensed on project abandonment, or amortized over their useful lives.

(j) GOODWILL

Goodwill represents the excess of an investment over the fair value of the net assets acquired. Goodwill is not amortized and is tested annually for impairment by comparing the book value with the fair value of the goodwill of the reporting unit to which the goodwill is attributable. Any deficiency in the book value compared to the fair value will be recognized as an impairment loss.

(k) REVENUE RECOGNITION

The Company recognizes revenues when products have been delivered or services have been performed.

The natural gas distribution utilities record revenues from natural gas sales on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year and are adjusted for the Revenue Stabilization Adjustment Mechanism and other BCUC approved orders.

For the petroleum transportation operations, revenues are recorded when products are delivered and adjusted according to terms prescribed by toll settlements with the shippers and approved by the respective regulator.

For the water and utility services operations revenues are recorded when services have been performed or products have been delivered.

(l) DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange, interest rates and energy commodity prices.

A derivative must be designated and effective to be accounted for as a hedge. The Company designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet, specific firm commitments or anticipated transactions. The Company also assesses, both at inception and on an ongoing basis, whether the derivative instruments that are used in each hedging transaction are highly effective in offsetting changes in fair values or cash flows of the hedged items. Derivatives accounted for as a hedge are not recognized in the consolidated financial statements.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Derivative financial instruments not designated as effective as a hedge are recorded at fair value at the balance sheet date. The carrying amount of these derivatives, which comprise unrealized gains and losses, are included in accounts receivable in the case of contracts in a gain position and accounts payable and accrued liabilities in the case of contracts in a loss position. The offsetting gain/loss is recorded in the rate stabilization accounts, as realized gains/losses are passed on to customers when realized.

The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions.

As approved by the regulator, derivatives are used to manage natural gas commodity price risk in the natural gas distribution operations. The majority of natural gas supply contracts have floating, rather than fixed prices. The Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in deferral accounts (CCRA and MCRA), and subject to regulatory approval, are passed through in future rates to customers.

Foreign currency risk in natural gas distribution operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through regulatory deferral accounts.

The Company's short-term borrowings and variable rate long-term debt are exposed to interest rate risk. The Company manages interest rate risk through the use of interest rate derivatives with payments and receipts under interest rate swap contracts being recognized as adjustments to financing costs.

The Company's earnings from the U.S. portion of Trans Mountain's crude oil pipeline system and the Company's investment in the Express System are subject to foreign currency risk. The Company manages some of these foreign currency exposures through the use of foreign currency derivatives.

Unless otherwise approved by regulation, if a derivative instrument is terminated or ceases to be effective prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Any subsequent changes in the value of the derivative instrument are reflected in income.

Non-hedge derivatives not subject to regulation are marked to market at the balance sheet date with fluctuations in value charged to earnings.

(m) POST-EMPLOYMENT BENEFIT PLANS

The Company sponsors a number of employee benefits plans. These plans include both defined benefit and defined contribution pension plans, and various other post-retirement benefit plans.

The cost of pensions and other post-retirement benefits earned by employees is actuarially determined as the employee provides service, except when the regulator requires costs to be expensed as paid. The Company uses the projected benefit method based on years of service and management's best estimates of expected returns on plan assets, salary escalation, retirement age of employees, mortality and expected future health-care costs. The discount rate used to value liabilities is based on AA Corporate bond yields. The Company accrues the cost of defined benefit pensions and post-employment benefits as the employee provides services, except when the regulator requires costs to be expensed as paid.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets as of December 31, 2005 is calculated as the average of the market value of invested assets at December 31, 2005 and two actuarially determined extrapolated market values of invested assets at December 31, 2005. The two extrapolated market values are calculated by using the market value of invested assets at December 31, 2003 rolled forward to December 31, 2005 using 2004 and 2005 net contributions and assumed investment returns, and the market value of invested assets at December 31, 2004 rolled forward to December 31, 2005 using 2005 net contributions and assumed investment returns. These three amounts are then averaged to determine the market-related value of plan assets used in calculating net benefit expense.

Adjustments, in excess of 10% of the greater of the accrued benefit obligation and plan asset fair value, that result from plan amendments, changes in assumptions and experience gains and losses, are amortized over the expected average remaining service life of the employee group covered by the plan. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

Defined contribution plan costs are expensed by the Company as contributions are payable.

(n) INCOME TAXES

The Company's regulated gas and petroleum operations account for and recover income tax expense in rates as prescribed by their respective regulators. This includes accounting for income taxes by the taxes payable method and accounting for certain deferral and rate stabilization accounts on a net of realized tax basis. Therefore, future income taxes related to temporary differences are not recorded. The taxes payable method is followed as there is a reasonable expectation that all future income taxes will be recovered in rates when they become payable.

The Company's non-regulated operations and FSW follow the asset and liability method of accounting for income taxes. Future income tax assets and liabilities are determined based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured at the tax rate that is expected to apply when the temporary differences reverse.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(o) STOCK-BASED COMPENSATION

The Company had a Share Option Plan whereby officers, directors and certain key employees may be granted options to purchase common shares. The Company uses the fair value based method for valuing stock options granted on or after January 1, 2003. Under the fair value based method, compensation cost is measured at the fair value at the date of grant and is expensed over the award's vesting period.

Prior to January 1, 2003, the Company used the settlement method of accounting for stock options, whereby any consideration paid by employees on the exercise of stock options was credited to common shares and no compensation expense was recognized.

The Company's Share Option Plan was discontinued on November 30, 2005 as a result of the acquisition of the Company by KMI.

The Company issued Deferred Share Units (''DSU's'') to senior management and Board members under long-term compensation programs and also as an optional form of compensation to Board members. The DSU's were marked-to-market at the end of each quarter and gains or losses were recognized in earnings. The DSU's notionally earned dividends that were reinvested as additional DSU's when dividends were paid, and were paid out in cash only on retirement or termination of the individual receiving them. The DSU's were paid out in cash upon the acquisition of the Company by KMI on November 30, 2005.

(p) LIABILITIES AND EQUITY

In accordance with recent changes to the CICA Handbook Section 3861 ''Financial Instruments — Disclosures and Presentation'', the Company's $125 million 8% Capital Securities have been reclassified from shareholders' equity to liabilities because the Capital Securities can be settled by issuing equity at a variable price dependent upon the market value of the Company's common shares at the settlement date. As a result of the change, distributions associated with the Capital Securities are now recorded as financing costs and the related income-tax benefits are recorded within income tax expense. Previously, the distributions were recorded on an after-tax basis as a deduction from net earnings to determine earnings applicable to common shares. There is no impact to earnings applicable to common shares or earnings per share. The changes have been applied retroactively and have increased long-term debt and decreased shareholders' equity, both by $125.0 million, compared to the amounts previously reported as at December 31, 2004. The restatement has also increased financing costs by $10.0 million, decreased income tax expense by $3.4 million and capital securities distributions by $6.6 million compared to the amounts previously reported for the year ended December 31, 2004.

(q) VARIABLE INTEREST ENTITIES

Effective January 1, 2005, the Company adopted the CICA Handbook Accounting Guideline 15 ''Consolidation of Variable Interest Entities''. The Company has performed a review of the entities with whom it conducts business and determined that under the definitions in the Guideline the Company's investment in Express US Holdings LP, part of the Express System, is deemed to be a variable interest entity. As the Company has not been identified as the primary beneficiary of Express US Holdings LP, the Company continues to account for its investment in the Express System on an equity basis. The Company's future exposure to loss regarding its investment is represented by the carrying value of the investment.

2. SEGMENT DISCLOSURES

2005

	Natural gas distribution	Petroleum transportation	Other activities	Total
Revenues	**$1,678.0**	**$ 227.8**	**$46.7**	**$1,952.5**
Cost of natural gas	**1,063.7**	**—**	**—**	**1,063.7**
Cost of revenues from other activities	**—**	**—**	**28.9**	**28.9**
Operation and maintenance	**195.8**	**82.3**	**42.6**	**320.7**
Depreciation and amortization	**96.7**	**37.6**	**8.3**	**142.6**
Property and other taxes	**47.4**	**24.6**	**(0.1)**	**71.9**
	1,403.6	**144.5**	**79.7**	**1,627.8**
Operating income	**274.4**	**83.3**	**(33.0)**	**324.7**
Financing costs	**129.2**	**31.7**	**30.5**	**191.4**
Share of (earnings) of Express System	**—**	**(21.9)**	**—**	**(21.9)**
Income taxes (recovery) on earnings	**54.4**	**9.0**	**(11.8)**	**51.6**
(Earnings) from Clean Energy net of disposition costs	**—**	**—**	**(2.5)**	**(2.5)**
Net earnings (loss) before discontinued operations	**90.8**	**64.5**	**(49.2)**	**106.1**
Earnings (loss) from discontinued operations	**—**	**—**	**(4.9)**	**(4.9)**
Net earnings (loss)	**90.8**	**64.5**	**(54.1)**	**101.2**
Total assets	**3,656.9**	**1,397.1**	**262.1**	**5,316.1**
Goodwill	**76.4**	**—**	**—**	**76.4**
Capital expenditures	**176.3**	**37.4**	**1.0**	**214.7**

2. SEGMENT DISCLOSURES (CONTINUED)

2004

	Natural gas distribution	Petroleum transportation	Other activities	Total
Revenues	$1,494.1	$ 225.5	$78.5	$1,798.1
Cost of natural gas	885.4	—	—	885.4
Cost of revenues from other activities	—	—	52.8	52.8
Operation and maintenance	190.5	66.0	18.2	274.7
Depreciation and amortization	98.7	35.9	9.9	144.5
Property and other taxes	47.1	22.5	0.3	69.9
	1,221.7	124.4	81.2	1,427.3
Operating income	272.4	101.1	(2.7)	370.8
Financing costs	126.2	22.5	26.9	175.6
Share of (earnings) of Express System	—	(15.0)	—	(15.0)
Income taxes (recovery) on earnings	50.3	22.7	(9.3)	63.7
Net earnings (loss)	95.9	70.9	(20.3)	146.5
Earnings from discontinued operations	—	—	3.3	3.3
Net earnings (loss)	95.9	70.9	(17.0)	149.8
Total assets	3,386.2	1,350.4	245.2	4,981.8
Goodwill	76.4	—	51.6	128.0
Capital expenditures	112.3	31.0	11.1	154.4

The segmented disclosures in these consolidated financial statements have been changed from those reported in the December 31, 2004 annual financial statements and no longer include the water and utility services business which are now reported as discontinued operations. Terasen's 30% share of CWLP is now included in other activities. The comparative segment information has been restated to reflect this change.

3. DISCONTINUED OPERATIONS

In January 2006, the Company entered into an agreement to sell Terasen Water and Utility Services, including the Company's 50% equity interest in FSW, to a consortium of external third parties and Terasen Water and Utility Services senior management. The sale does not include the Company's interest in CWLP. The proceeds are anticipated to approximate the consolidated net carrying value of the discontinued operations at December 31, 2005, and no significant gains or losses are expected to occur upon the disposition. The Company anticipates that the sale will be completed at the end of April 2006.

The Company has classified, at December 31, 2005, the assets and liabilities of the entities being sold as assets and liabilities held for sale. The revenue and expense items for 2005 have been classified as net earnings (loss) from discontinued operations and the comparative figures have been restated to conform with this presentation. Gross revenues applicable to the Terasen Water and Utility Services group were $205.1 million in 2005 (2004 — $158.9 million) and pre-tax income was $1.4 million (2004 — $6.4 million). The 2005 pre-tax income includes a charge to earnings of $7.2 million related to currency translation losses arising on the Company's investment in self sustaining foreign operations. Income taxes from discontinued operations includes a charge of $3.4 million on operating earnings from the entities and a write-off of $2.9 million of tax losses expiring as a result of the change in control.

4. ACQUISITIONS AND DISPOSITIONS

DISPOSITION OF CLEAN ENERGY

On October 31, 2005, the Company sold its 40.38% ownership in Clean Energy for proceeds of approximately U.S. $35.9 million. The sale, together with equity earnings of Clean Energy for the nine months ended September 30, 2005, resulted in a gain of $2.5 million, including the recognition of all unrealized gas forward contract gains of Clean Energy in 2005 totalling $10.9 million and the recognition of currency translation losses previously included in shareholders' equity totalling $8.4 million.

WATER AND UTILITY SERVICES ACQUISITIONS

In 2005 the Company purchased two water and utility services businesses for total cash proceeds of $11.2 million. The cash used to purchase these businesses has been included in Investing activities of Discontinued Operations on the Statements of Cash Flow.

On July 31, 2004, the Company acquired a 50 per cent interest in FSW. FSW provides water and wastewater treatment and water distribution and wastewater collection services to Fairbanks, Alaska. The Company paid $40.8 million for its 50 per cent interest after working capital adjustments. The Company has accounted for the acquisition of FSW using the purchase method and has proportionately consolidated its 50% of operations since the date of acquisition.

The Company and the other owners of FSW each have the option to have Terasen acquire the remaining 50 per cent interest in FSW at fair market value in 2009.

During 2004, the Company also acquired 100% of two businesses and increased its investment in two other businesses that provide meter reading, meter fleet management and installation services in Canada and the United States. The Company paid $17.1 million for the interest in

4. ACQUISITIONS AND DISPOSITIONS (CONTINUED)

these businesses after working capital adjustments. The earnings of these acquired businesses have been included in the statement of earnings from the date of acquisition.

The following table provides the allocation of the purchase price over the assets and liabilities acquired in 2004:

	FSW	Other	Total
Working capital	$ 2.2	$ 7.1	$ 9.3
Property, plant and equipment	27.0	1.6	28.6
Goodwill	24.0	8.0	32.0
Other assets	0.5	0.4	0.9
Future income taxes	(2.0)	—	(2.0)
Long-term debt assumed	(10.9)	—	(10.9)
Total cash paid	$ 40.8	$17.1	$ 57.9

5. INVESTMENTS IN JOINTLY-CONTROLLED ENTITIES

As at December 31, 2005, the Company has a 30% interest in CWLP and a 50% interest in FSW for which it uses the proportionate consolidation method of accounting. The comparative information for 2004 in the table below includes the Company's interest in Clean Energy which was accounted for under the proportionate consolidated method until the first quarter of 2005, and then equity-accounted until the interest in Clean Energy was sold in 2005. The revenue, expenses, and net income for 2004 has been restated to present the net earnings of the Company's 50% interest in FSW's as earnings from discontinued operations. The Company's proportionate interest in the assets and liabilities of FSW are excluded from the table below as they are classified as assets and liabilities held for sale at December 31, 2005. The Company's proportionate interest in FSW at December 31, 2005 includes $52.8 million of assets and $16.0 million of liabilities, all of which are classified as held for sale.

The Company's proportionate share of assets, liabilities, revenues, expenses, and cash flows related to these entities proportionately consolidated is summarized as follows:

	2005	2004
Current assets	**$10.2**	$ 27.1
Long-term assets (including property, plant and equipment and goodwill)	**35.6**	121.0
Current liabilities	**39.4**	41.3
Long-term liabilities	**—**	20.4
Revenues	**43.5**	73.0
Expenses (including financing costs and income tax)	**36.4**	67.7
Net earnings from continuing operations	**7.1**	5.3
Earnings from discontinued operations	**1.7**	0.6
Cash flows from operating activities	**13.9**	7.8
Cash flows from investing activities	**(0.1)**	(7.5)
Cash flows from financing activities	**—**	0.2

6. PROPERTY, PLANT AND EQUIPMENT

2005

	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas distribution systems	**2.31%**	**$3,093.9**	**$ 596.7**	**$2,497.2**
Petroleum pipeline systems	**2.59%**	**1,329.5**	**329.7**	**999.8**
Plant, buildings and equipment	**9.13%**	**427.4**	**167.0**	**260.4**
Land and land rights	**0.15%**	**153.2**	**2.7**	**150.5**
		$5,004.0	**$1,096.1**	**$3,907.9**

2004

	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas distribution systems	2.40%	$3,009.6	$ 542.5	$2,467.1
Petroleum pipeline systems	2.51%	1,295.0	295.9	999.1
Water and utility plant and distribution systems	3.71%	34.0	1.8	32.2
Plant, buildings and equipment	8.98%	404.4	160.3	244.1
Land and land rights	0.25%	152.6	2.6	150.0
		$4,895.6	$1,003.1	$3,892.5

6. PROPERTY, PLANT AND EQUIPMENT (CONTINUED)

As allowed by the regulators, during the year ended December 31, 2005 the Company capitalized an allowance for equity funds during construction at approved rates of $1.0 million (2004 — $1.0 million) and approved capitalized overhead of $31.1 million (2004 — $31.1 million), with offsetting inclusions in earnings.

7. RATE STABILIZATION ACCOUNTS

	2005	2004
Current Assets		
RDDA	**$12.8**	$12.9
RSAM	**13.0**	11.1
CCRA	**—**	2.7
Gas Cost Variance Account (TGVI)	**2.6**	0.4
	28.4	27.1
Long-Term Assets		
RDDA	**22.4**	32.7
RSAM	**25.9**	27.9
	48.3	60.6
Current Liabilities		
CCRA	**(21.3)**	—
MCRA	**(26.6)**	(27.6)
	(47.9)	(27.6)
Net rate stabilization accounts	**$28.8**	$60.1

The current portion of the rate stabilization accounts represents the amounts expected to be recovered or refunded in rates over the next year. Actual recoveries/(refunds) will vary depending on actual natural gas consumption and recovery amounts approved by the BCUC.

The RSAM account is anticipated to be recovered in rates over three years. Recovery of the RSAM balance is dependent upon annually approved rates and actual gas consumption volumes. The MCRA and CCRA accounts, which succeeded the GCRA account in 2004, are anticipated to be fully recovered or paid within the next fiscal year.

8. OTHER ASSETS

	2005	2004
Deferred charges		
Subject to rate regulation and approved for recovery in rates		
Income taxes recoverable on post-employment benefits	**$10.6**	$ 8.4
Long-term debt issue costs	**9.5**	8.6
Commercial commodity unbundling costs	**3.2**	4.0
Replacement transportation agreement	**3.2**	3.6
Other items included approved for recovery in rates	**12.2**	10.9
Subject to rate regulation but not yet approved for recovery in rates		
Deferred development costs for capital projects	**19.5**	7.9
Corporate capital tax deferrals	**7.5**	7.7
Inland Pacific Connector Development costs	**—**	5.4
Other items subject to rate regulation but not yet approved	**1.7**	0.9
Included in non-regulated entities		
Long-term debt issue costs	**1.0**	1.6
Other items included in non-regulated entities	**2.7**	12.4
	71.1	71.4
Investments	**2.2**	1.3
Long-term receivables	**11.5**	14.7
	$84.8	$87.4

Amortization of these deferred charges in rates for the year ended December 31, 2005 totalled $11.3 million (2004 -$9.0 million).

The deferral account for income taxes on post-employment benefits relates to income tax amounts on post employment benefit expense. The BCUC allows post-employment benefits to be collected from customers through rates calculated on the accrual basis, rather than a cash paid basis, which produces timing differences for income tax purposes. Since Terasen Gas accounts for income taxes using the taxes payable basis of accounting, the tax effect of this timing difference is included in other assets, and will be reduced as cash payments for post-employment benefits exceed required accruals and amounts collected from customers in rates.

Long-term debt issue costs are amortized over the terms of the related debt, whose maturity dates are provided in Note 9 ''Long-Term Debt''.

8. OTHER ASSETS (CONTINUED)

The commercial commodity unbundling costs deferred are costs incurred to develop a third-party marketer alternative for commercial customers to purchase natural gas from suppliers other than Terasen Gas. The BCUC has approved the recovery of these costs in rates over a five-year period, of which four years remain at December 31, 2005.

The deferral account for the replacement transportation agreement relates to amounts that Terasen Gas is allowed to recover from customers in rates in order to cover any shortfall in revenues relative to a minimum amount approved by the BCUC on the Company's Southern Crossing Pipeline. The deferral account is being amortized and recovered in rates over a five-year period, of which four years remain at December 31, 2005.

Deferred development costs for capital projects include costs for projects under development that are expected to be added to regulated rate-base in future periods. These costs include approximately $16.2 million for Trans Mountain TMX expansion costs and $3.3 million for capital projects that are currently in progress by the natural gas distribution operations.

The deferral for corporate capital tax relates to tax payments that were made to the province of British Columbia (''the Province'') related to assessments for corporate capital tax for TGVI and Terasen Gas which the Company believes were incorrectly assessed. The Company is currently in the process of appealing the tax assessments and depending on the success of the appeals, the Company will either be refunded these amounts from the Province or alternatively expects to recover the costs from customers in future rates.

On October 5, 2005, the British Columbia Utilities Commission issued a decision that denied recovery of approximately $5.4 million of costs that Terasen Gas incurred to develop the Inland Pacific Connector pipeline project that is planned to bring new gas transmission capacity to the Lower Mainland of British Columbia when economic conditions make the project viable. The Company still believes that the project is viable and intends to keep all existing permits and land right approvals in place that have already been granted. Terasen Gas has filed an application to have the decision reconsidered, but has recorded an after-tax provision of $3.6 million at December 31, 2005.

Deferred charges for rate regulated entities that have been aggregated in the table above and in the table in ''Other Long-term Liabilities and Deferred Credits'' in Note 10 relate to more than fifty deferral accounts, none of which exceed $1.6 million individually. All of these accounts have been approved by regulators in prior annual rate approvals or orders and are being amortized over various periods depending on the nature of the costs.

9. LONG-TERM DEBT

	2005	2004
Terasen Inc.		
(a) Medium Term Note Debentures:		
6.30% Series 1, due December 1, 2008	**$ 200.0**	$ 200.0
4.85% Series 2, due May 8, 2006	**100.0**	100.0
5.56% Series 3, due September 15, 2014	**125.0**	125.0
(b) 8% Capital Securities, due April 19, 2040	**125.0**	125.0
	550.0	550.0
Terasen Gas Inc.		
(c) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2015	**74.9**	74.9
10.30% Series B, due September 30, 2016	**200.0**	200.0
(d) Debentures and Medium Term Note Debentures:		
9.75% Series D, due December 17, 2006	**20.0**	20.0
10.75% Series E, due June 8, 2009	**59.9**	59.9
6.20% Series 9, due June 2, 2008	**188.0**	188.0
6.95% Series 11, due September 21, 2029	**150.0**	150.0
6.50% Series 12, due July 20, 2005	**—**	200.0
6.50% Series 13, due October 16, 2007	**100.0**	100.0
6.15% Series 16, due July 31, 2006	**100.0**	100.0
Floating Rate Series 17, interest rate of 2.93% (2004) due September 26, 2005	**—**	150.0
6.50% Series 18, due May 1, 2034	**150.0**	150.0
5.90% Series 19, due February 26, 2035	**150.0**	—
Floating Rate Series 20, interest rate of 3.36% due October 24, 2007	**150.0**	—
Various series, weighted average interest rate of 9.63% (2004 — 9.63%) due in 2005	**—**	45.0
Obligations under capital leases, at 6.07% (2004 — 6.23%)	**8.8**	10.8
	1,351.6	1,448.6
Terasen Gas (Vancouver Island) Inc.		
(e) Syndicated credit facility at short-term floating rates, weighted average interest rate of 3.88% (2004 — 3.35%) with maturities of $176.5 million in 2006 and $33.0 million in 2009	**209.5**	214.9
Terasen Pipelines (Trans Mountain) Inc.		
(f) Debentures:		
11.50% Series C, due June 20, 2010	**—**	35.0
	—	35.0
Terasen Pipelines (Corridor) Inc.		
(g) Debentures:		
4.24% Series A, due February 2, 2010	**150.0**	—
5.033% Series B, due February 2, 2015	**150.0**	—
(h) Commercial Paper at short-term floating rates, weighted average interest rate of 2.61% (2004 — 2.51%)	**—**	446.0
	300.0	446.0
Other long-term debt	**—**	13.8
Total long-term debt	**2,411.1**	2,708.3
Less: current portion of long-term debt	**398.2**	416.7
	$2,012.9	$2,291.6

(a) TERASEN INC. MEDIUM TERM NOTE DEBENTURES:
The Company's Medium Term Note Debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 21, 2001.

(b) TERASEN INC. CAPITAL SECURITIES:
On April 19, 2000, the Company issued $125.0 million of 8.0% Capital Securities with a term to maturity of 40 years for gross proceeds of $123.7 million. The Company may elect to defer payments on these securities and settle such deferred payments in either cash or common shares, and has the option to settle principal at maturity through the issuance of common shares. The securities are exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90% of the market price, subject to the right of the Company to redeem the securities for cash. Distributions on these securities, net of related income taxes, are deducted from net earnings for the purposes of calculating earnings applicable to common shares.

9. LONG-TERM DEBT (CONTINUED)

(c) TERASEN GAS INC. PURCHASE MONEY MORTGAGES:
The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on Terasen Gas' Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

(d) TERASEN GAS INC. DEBENTURES AND MEDIUM TERM NOTE DEBENTURES:
Terasen Gas' debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

(e) TERASEN GAS (VANCOUVER ISLAND) INC. BANK SYNDICATE:
The credit facility from the syndicate of banks is secured by a first floating charge over all of the assets of TGVI, assignment of certain material contracts, and assignment of royalty revenue and interruptible incentive payments. Subsequent to year-end the credit facility was renegotiated, and further information is disclosed in Note 19 ''Subsequent Events''.

(f) TERASEN PIPELINES (TRANS MOUNTAIN) INC. DEBENTURES:
The Trans Mountain debentures were unsecured obligations but were subject to the restrictions of the Trust Indenture dated February 18, 1987, as amended and supplemented.

On November 1, 2005, Trans Mountain redeemed the 11.50% Series C Debentures, due June 20, 2010. The total redemption price for the Debentures included a redemption premium of $10.9 million which has been reflected in financing costs for the year ended December 31, 2005. The Company has recognized an income tax benefit associated with the redemption costs of $3.6 million in income taxes for the year ended December 31, 2005.

(g) TERASEN PIPELINES (CORRIDOR) INC. DEBENTURES PAPER:
On February 1, 2005, Terasen Pipelines (Corridor) Inc. (''Corridor'') issued $150 million Series A Debentures and $150 million Series B Debentures. The debentures are unsecured and subject to restrictions of the Trust Indenture. The proceeds were used to repay a portion of Corridor's outstanding commercial paper.

Concurrent with the debenture issuance, Corridor entered into an operating credit facility which has annual renewal provisions. The credit facility is unsecured and will backstop Corridor's commercial paper issuance.

The Company's Series 1 and Series 3 Medium Term Note Debentures and Capital Securities, Terasen Gas' Series B Purchase Money Mortgages, Series E Debentures, and Series 11, Series 13, Series 16, Series 18, and Series 19 Medium Term Note Debentures, and Terasen Pipelines (Corridor) Inc. Series A and Series B Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Required principal repayments over the next five years are as follows:

2006	$398.2
2007	251.8
2008	389.7
2009	94.6
2010	151.8

10. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS

	2005	2004
Pension and other post-employment benefit liabilities	**$ 39.7**	$ 30.8
Deferred gains on sale of natural gas distribution assets	**59.2**	60.3
Deferred payment	**36.0**	33.9
Deferred credits		
Subject to rate regulation and approved for refund in rates		
Earnings Sharing Mechanism	**8.8**	1.6
Deferred Interest Mechanism	**2.4**	2.5
Other items included approved for repayment in rates	**6.8**	8.2
Other deferred credits in entities subject to rate regulation	**1.7**	1.8
Other deferred credits/liabilities	**13.9**	16.9
	$168.5	$156.0

The deferred gains on sale of natural gas distribution assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $70.5 million on combined cash proceeds of $141.1 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 17.

10. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS (CONTINUED)

The deferred payment resulted from the Company's acquisition of TGVI effective January 1, 2002. The deferred payment has a face value of $52.0 million but was discounted at January 1, 2002 to a present value of $28.2 million. The payment is due on December 31, 2011 or sooner if TGVI realizes revenues from transportation revenue contracts to serve power-generating plants which may be constructed in TGVI's service area. If any part of the deferred payment is paid prior to December 31, 2011, the difference between the payment and the carrying value of the debt will be treated as contingent consideration for the acquisition of TGVI and will be added to the cost of the purchase at that time.

The Earnings Sharing Mechanism is a mechanism agreed to in Terasen Gas' multi-year agreement to share, on a 50/50 basis, amounts earned by Terasen Gas on its regulated activities that exceed or are less than amounts allowed by the BCUC in the cost-of-service allowed return calculations. These amounts are shared on an after-tax basis, and are returned to customers in rates.

Terasen Gas has a deferred interest mechanism which has been approved by the BCUC which requires that variances due to differences in long-term and short-term borrowings and interest rates from those that have been approved in rates be returned to customers in future rates. The impact of this mechanism was to increase financing costs for the year ended December 31, 2005 by $2.0 million (2004 — $1.4 million) from what otherwise would be reported. The balance of the deferred interest account is being amortized on a straight-line basis over three years.

Other deferred credits/liabilities includes amounts resulting from the Company's acquisition of TGVI effective January 1, 2002.

Amortization of deferred credits in entities that are subject to rate regulation in rates for the year ended December 31, 2005 totalled $4.5 million (2004 — $3.8 million).

11. SHARE CAPITAL

AUTHORIZED SHARE CAPITAL
The Company is authorized to issue 750,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

STOCK SPLIT
On June 14, 2004 the Company carried out a two-for-one stock split effected by paying a stock dividend of one additional common share for each common share held as of June 7, 2004.

All equity-based benefit plans have been amended to reflect the additional shares or options resulting from the stock split. All share and per share data has been amended for comparative and current periods to reflect the stock split.

COMMON SHARES
Changes in the issued and outstanding common shares are as follows:

	2005		2004	
	Number	**Amount**	Number	Amount
Outstanding, beginning of year	**114,355,665**	**$883.4**	113,338,942	$868.7
Issued under:				
Share option plan	**1,283,146**	**21.3**	1,009,761	14.5
Employee share purchase plan	**4,351**	**0.2**	6,962	0.2
	115,643,162	**$904.9**	114,355,665	$883.4
Less common shares held by Trans Mountain	**9,184,188**		9,184,188	
Outstanding, end of year	**106,458,974**		105,171,477	

As at December 31, 2005, Trans Mountain owned 7.9% (2004 — 8.0%) of the common shares of Terasen Inc. The cost of these shares is shown as a deduction from shareholder's equity.

All of the shares outstanding at December 31, 2005 are owned by KMI.

12. SHARE OPTION PLAN AND STOCK-BASED COMPENSATION

SHARE OPTION PLAN
The Company had a Share Option Plan whereby officers and certain key employees could be granted options to purchase a maximum of 12,600,000 unissued common shares with terms up to ten years. There were two categories of options which were issued under the Share Option Plan, Regular Share Options and Performance Based Share Options. The option exercise price was the closing sale price of the common shares on the Toronto Stock Exchange on the trading day prior to the date the option was granted. The Share Option Plan was discontinued on November 30, 2005 as a result of the acquisition of the Company by KMI.

REGULAR SHARE OPTIONS
Since 2000, the Company had granted options with eight-year terms which were exercisable on a cumulative basis and vested at one-third per year on the anniversary of the option grant date. Prior to 2000, the Company granted options with ten-year terms which were exercisable on a cumulative basis at 20% per year.

12. SHARE OPTION PLAN AND STOCK-BASED COMPENSATION (CONTINUED)

REGULAR SHARE OPTIONS OUTSTANDING

	2005		2004	
	Shares under option	**Weighted-average exercise price**	Shares under option	Weighted-average exercise price
Outstanding, beginning of year	**565,868**	**$15.53**	1,118,822	$14.31
Options granted during the year	**5,000**	**29.45**	24,800	23.93
Options exercised	**(287,165)**	**15.15**	(537,716)	13.39
Options forfeited, cancelled and expired	**(82,991)**	**11.59**	(40,038)	17.46
Options purchased by KMI and cancelled	**(200,712)**	**18.12**	—	—
Outstanding, end of year	**—**	**$ —**	565,868	$15.40
Options exercisable, end of year	**—**	**$ —**	348,857	$13.25

PERFORMANCE BASED SHARE OPTIONS

The Company had granted performance based share options with eight-year terms. The options vested at one-third per year on the anniversary of the option grant dates, subject to the market price of the Company's common shares reaching 125% of the option's exercise price for at least 10 out of 15 consecutive trading days within four years of the option grant date. If the market price requirement was not attained within four years of grant date, the participant was still eligible to exercise two-thirds of the granted options if the common share price reached 125% of the option's exercise price for at least 10 out of 15 consecutive trading days during the subsequent four years.

PERFORMANCE BASED SHARE OPTIONS OUTSTANDING

	2005		2004	
	Shares under option	**Weighted-average exercise price**	Shares under option	Weighted-average exercise price
Outstanding, beginning of year	**2,339,619**	**$19.28**	2,304,398	$17.08
Options granted during the year	**850,200**	**29.45**	716,600	23.88
Options exercised	**(995,981)**	**16.96**	(472,045)	15.53
Options forfeited, cancelled and expired	**(262,574)**	**17.09**	(209,334)	19.68
Options purchased by KMI and cancelled	**(1,931,264)**	**25.12**	—	—
Outstanding, end of year	**—**	**$ —**	2,339,619	$19.24
Options exercisable, end of year	**—**	**$ —**	1,020,508	$16.27

STOCK-BASED COMPENSATION

In 2005, 855,200 stock options were granted (2004 — 741,400) at an average exercise price of $29.45 (2004 — $23.88) under the Company's Share Option Plan. The Company has applied the fair value based method of accounting for stock options granted after January 1, 2003. Reported earnings for 2005 include a compensation charge of $2.0 million (2004 — $1.2 million) representing the fair value of options granted in 2003, 2004 and 2005 amortized over their respective vesting periods, with a corresponding increase to contributed surplus. Just prior to the acquisition of the Company by KMI, any outstanding but not yet exercisable options became immediately exercisable and an additional pre-tax charge of $3.6 million was recorded to recognize the accelerated vesting of the remaining options. The options were then purchased by KMI and subsequently cancelled. Had the Company used the fair value based method to account for stock options granted during 2002, pro forma earnings and earnings per share would have been as follows:

		Year ended December 31, 2004
Net earnings	As reported	$149.8 million
	Pro forma	$148.6 million

A Black-Scholes model was used to calculate stock option fair values. The weighted average fair value of options granted in 2005 was $4.33 (2004 — $2.40). Significant assumptions in valuing the options were as follows:

	2005		2004	
	Regular Options	**Performance Based**	Regular Options	Performance Based
Interest rate	3.6%	3.7%	3.5 - 3.7%	3.5%
Expected volatility	16.5%	16.5%	15.1 - 15.4%	15.4%
Expected life	5 years	6 years	5 years	6 years

12. SHARE OPTION PLAN AND STOCK-BASED COMPENSATION (CONTINUED)

DEFERRED SHARE UNITS

The Company had issued Deferred Share Units (''DSU's'') to certain senior employees and directors. At December 31, 2005, there were no (2004 — 52,859) DSU's outstanding due to the payment of all outstanding DSU's at the acquisition of the Company by KMI on November 30, 2005. The liability at December 31, 2005 was nil (2004 — $1.5 million) and was included in other long-term liabilities and deferred credits.

13. EMPLOYEE BENEFIT PLANS

The Company is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. The Company also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan:

DEFINED BENEFIT PLANS

Retirement benefits under the defined benefit plans are based on employees' years of credited service and remuneration. Company contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were at December 31, 2004 and December 31, 2002 and the date of the next required valuations are December 31, 2005 and December 31, 2007. The December 31, 2005 valuations will not be completed until the second quarter of 2006. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 11.8 years (2004 — 11.8 years).

DEFINED CONTRIBUTION PLAN

Effective in 2000 for Terasen Gas and 2003 for petroleum transportation operations, all new non-union employees become members of defined contribution pension plans. Company contributions to the plan are based upon employee age and pensionable earnings for employees of the natural gas distribution operations and pensionable earnings for employees of the petroleum transportation operation.

SUPPLEMENTAL PLANS

Certain employees are eligible to receive supplemental benefits under both the defined benefit and defined contribution plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and are secured by letters of credit.

OTHER POST-EMPLOYMENT BENEFITS

The Company provides retired employees with other post-employment benefits that include, depending on circumstances, supplemental health, dental and life insurance coverage. Post-employment benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health care cost escalation. The most recent actuarial valuations were completed as at December 31, 2002 and the December 31, 2005 valuation will not be completed until second quarter of 2006. The expected weighted average remaining service life of employees covered by these benefit plans is 9.9 years (2004 — 9.9 years).

13. EMPLOYEE BENEFIT PLANS (CONTINUED)

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 each year. The financial positions of the employee defined benefit pension plans and other benefit plans are presented in aggregate in the tables below:

	Pension benefit plans		Other benefit plans	
	2005	2004	**2005**	2004
Plan assets				
Fair value, beginning of year	**$274.5**	$255.3	**$ —**	$ —
Company contributions	**6.9**	5.5	**1.6**	1.5
Contributions by members	**3.3**	2.9	**—**	—
Actual return on plan assets	**28.6**	26.7	**—**	—
Benefits paid	**(14.3)**	(15.2)	**(1.5)**	(1.4)
Other	**(0.5)**	(0.7)	**(0.1)**	(0.1)
Fair value, end of year	**298.5**	274.5	**—**	—
Accrued benefit obligation				
Balance, beginning of year	**298.0**	276.7	**67.3**	61.0
Service cost	**8.5**	8.1	**1.4**	1.3
Interest cost	**17.9**	17.2	**4.1**	3.9
Benefit payments	**(14.3)**	(15.2)	**(1.5)**	(1.4)
Contributions by members	**3.3**	2.9	**—**	—
Plan amendments and curtailments	**0.9**	—	**—**	—
Past service cost	**0.3**	0.5	**0.4**	—
Actuarial loss	**2.8**	—	**—**	—
Change in discount rate	**27.0**	7.8	**10.2**	2.5
Balance, end of year	**344.4**	298.0	**81.9**	67.3
Plan surplus (deficiency)	**(45.9)**	(23.5)	**(81.9)**	(67.3)
Unamortized transitional obligation (benefit)	**(23.8)**	(27.2)	**4.7**	6.2
Unamortized actuarial loss	**62.7**	43.2	**39.7**	32.0
Unamortized past service costs	**7.4**	9.0	**(2.6)**	(3.2)
Accrued benefit asset (liability)	**$ 0.4**	$ 1.5	**$(40.1)**	$(32.3)

The net accrued benefit liability is included in other long-term liabilities and deferred credits (Note 10).

Included in the accrued benefit obligation and fair value of the plan assets at year-end are the following amounts in respect of plans with accrued benefit obligations in excess of fair value of assets:

	Pension benefit plans		Other benefit plans	
	2005	2004	**2005**	2004
Accrued benefit obligations:				
Unfunded plans	**$ 35.9**	$ 28.0	**$ 81.9**	$ 67.3
Funded plans	**258.0**	156.5	**—**	—
	293.9	184.5	**81.9**	67.3
Fair value of plan assets	**246.2**	151.9	**—**	—
Funded status deficit	**$ (47.7)**	$ (32.6)	**$(81.9)**	$(67.3)

The accrued benefit obligations for unfunded pension benefit plans are secured by letters of credit.

13. EMPLOYEE BENEFIT PLANS (CONTINUED)

The net benefit plan expense is as follows:

	Pension benefit plans		Other benefit plans	
	2005	2004	**2005**	2004
Current service cost	**$ 8.7**	$ 8.1	**$1.6**	$1.3
Interest cost on projected benefit obligations	**17.9**	17.2	**4.1**	3.9
Actual return on plan assets	**(28.6)**	(26.7)	**—**	—
Net actuarial gains	**29.8**	7.8	**9.0**	2.5
Past service costs	**0.3**	0.5	**—**	—
Impact of curtailment/settlement	**0.9**	—	**—**	—
Net benefit plan expense before adjustments	**29.0**	6.9	**14.7**	7.7
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return on plan assets	**9.2**	7.7	**—**	—
Difference between actual and recognized actuarial gains (losses) in year	**(26.8)**	(5.2)	**(6.4)**	0.1
Difference between actual and recognized past service costs in year	**0.4**	0.1	**(0.3)**	(0.3)
Special termination benefits	**(0.7)**	—	**—**	—
Amortization of transitional obligation (benefit)	**(3.4)**	(3.4)	**1.6**	1.6
Other	**—**	1.5	**—**	—
Net benefit plan expense	**$ 7.7**	$ 7.6	**$9.6**	$9.1
Defined contribution plan expense	**$ 1.6**	$ 2.3		
	$ 9.3	$ 9.9		

BENEFIT PLAN ASSETS

The weighted-average asset allocation by asset category of the Company's funded defined benefit pension plans is as follows:

	Pension benefit plans	
	2005	2004
Equity securities	**57%**	55%
Fixed income securities	**38%**	40%
Other assets	**5%**	5%
Total assets	**100%**	100%

The investment policy for benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Company's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost-effective manner while not compromising the security of the respective plans. The pension plans utilize external investment managers to manage the investment policy. Assets in the plan are held in trust by independent third parties.

The pension plans do not directly hold any shares of the Company.

SIGNIFICANT ASSUMPTIONS

The discount rate assumption used in determining pension and post-retirement benefit obligations and net benefit expense reflects the market yields, as of the measurement date, on high-quality debt instruments. The expected rate of return on plan assets assumption is reviewed annually by management, in conjunction with actuaries. The assumption is based on the expected returns for the various asset classes, weighted by the portfolio allocation.

The weighted average significant actuarial assumptions used to determine the accrued benefit obligation and the benefit plan expense are as follows:

	Pension benefit plans		Other benefit plans	
	2005	2004	**2005**	2004
Accrued benefit obligation				
Discount rate at December 31, based on AA Corporate bonds	**5.00%**	6.00%	**5.00%**	6.00%
Rate of compensation increase	**3.50%**	3.50%	**—**	—
Net benefit plan expense				
Discount rate at January 1, based on AA Corporate bonds	**6.00%**	6.25%	**6.00%**	6.25%
Expected rate of return on plan assets	**7.50%**	7.50%	**—**	—

13. EMPLOYEE BENEFIT PLANS (CONTINUED)

The assumed health-care cost trend rates for other post-employment benefit plans are as follows:

	2005	2004
Extended health benefits		
Initial health care cost trend rate	**9.0%**	9.0%
Annual rate of decline in trend rate	**1.0%**	1.0%
Ultimate health care cost trend rate	**5.0%**	5.0%
Year that the rate reaches the ultimate trend rate	**2008**	2008
Medical Services Plan Benefits Premium trend rate	**4.0%**	4.0%

A one percentage-point change in assumed health-care cost trend rates would have the following effects:

2005	**One percentage-point increase**	**One percentage-point decrease**
Effect on the total of the service cost and interest cost components of the benefit plan expense	$ 1.5	$ (1.2)
Effect on accrued benefit obligation	15.5	(12.9)

CASH FLOWS

Total cash contributions for employee benefit plans consist of:

	Employee benefit plans	
	2005	2004
Funded plans	**$ 5.3**	$4.3
Beneficiaries of unfunded plans	**3.2**	2.7
Defined contribution plans	**1.6**	2.3
Total	**$10.1**	$9.3

The contributions for 2006 are anticipated to be approximately the same as 2005 for both the defined pension benefit plans and other benefit plans.

BENEFIT CHANGES

Effective January 1, 2004, the Company modified its post-employment benefit program for non-union active employees in order to provide future retirees with more choice of coverage and to reduce the Company's exposure to future health and group life cost increases. The new plan is predominantly a defined contribution plan incorporating a Company-paid health spending account, a security health plan and life insurance. Provincial medical services plan premiums will now be paid by the retiree.

All plan members who have retired on or before December 31, 2004 receive benefits under the plans that were in effect when they retired, which includes the payment of provincial medical services plan premiums by the Company. Employees electing to retire during 2005 will have a choice between the new and old plan, and employees retiring after December 31, 2005 will participate in the new plan.

These assumptions, including the post-employment benefit plan changes, were included in the calculation of the accrued benefit obligation at December 31, 2003, 2004 and 2005.

IMPACT OF RATE REGULATION

As required by the regulator, Terasen Gas is required under its approved cost of service model to defer the amounts of pension benefit expense that exceed or are less than the amounts approved by the regulator to be recovered in rates each year. During the year ended December 31, 2005 the Company has deferred pension expense of $0.3 million that exceeded the amount approved by the regulator to be recovered in rates for 2005.

14. FINANCING COSTS

	2005	2004
Interest and expense on long-term debt	**$177.9**	$151.6
Interest on short-term debt	**15.0**	25.1
Interest capitalized	**(1.5)**	(1.1)
	$191.4	$175.6

Included in interest expense on long-term debt for the year ended December 31, 2005 is $10.9 million of redemption premium paid on the redemption of Trans Mountain Debentures during the year.

As allowed by the regulators, during the year ended December 31, 2005, the Company capitalized interest for borrowing requirements for construction of assets that have not been included in rate base of $1.5 million (2004 — $1.1 million).

15. INCOME TAXES

PROVISION FOR INCOME TAXES

	2005	2004
Current income taxes	**$48.7**	$66.3
Future income taxes	**2.9**	(2.6)
	$51.6	$63.7

VARIATION IN EFFECTIVE INCOME TAX RATE

Consolidated income taxes vary from the amount that would be computed by applying the Canadian and United States Federal, British Columbia and Alberta combined statutory income tax rate of 33.77% (2004 — 34.52%) to earnings before income taxes as shown in the following table:

	2005	2004
Earnings before income taxes	**$157.7**	$210.2
Combined statutory income tax rate	**33.77%**	34.52%
Combined income taxes at statutory rate	**$ 53.3**	$ 72.6
Increase (decrease) in income taxes resulting from:		
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	**(10.0)**	(14.7)
Large Corporations Tax in excess of surtax	**6.1**	6.5
Non-deductible expenses and non-taxable income	**9.6**	5.5
Benefit of tax rate changes on losses	**—**	(0.4)
Equity income not subject to tax	**(4.7)**	(3.3)
Write-off of restricted tax loss carryforwards	**5.9**	—
Other permanent differences	**(8.0)**	(2.6)
Other	**(0.6)**	0.1
Actual consolidated income taxes	**$ 51.6**	$ 63.7
Effective income tax rate	**32.72%**	30.30%

FUTURE INCOME TAXES

The net future income tax liability of the Company of $88.7 million (2004 — $68.7 million) relates primarily to the tax effect of temporary differences on non-regulated property, plant and equipment balances and tax benefits repayable to shippers in future periods.

As a result of the Company accounting for income taxes following the taxes payable method for its natural gas distribution and petroleum transportation regulated operations, the Company has not recognized net future income tax liabilities amounting to $301.8 million at December 31, 2005 (2004 — $278.7 million) and has not recognized a future income tax expense of $23.1 million for the year ended December 31, 2005 (2004 — $15.2 million), all of which were calculated using the asset and liability method.

16. FINANCIAL INSTRUMENTS

FAIR VALUE ESTIMATES

The carrying values of cash and short-term investments, accounts receivable, short-term notes and accounts payable and accrued liabilities approximate their fair values due to the relatively short period to maturity of the instruments.

The fair value of the Company's investment in the Express System is estimated to approximate its carrying value.

The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2005, or by using available quoted market prices, is estimated at $2,673.4 million (2004 — $2,818.2 million). The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

DERIVATIVE INSTRUMENTS

The Company uses derivative instruments to hedge its exposures to fluctuations in natural gas prices, interest rates and foreign currency exchange rates.

16. FINANCIAL INSTRUMENTS (CONTINUED)

Asset (Liability)	Number of swaps and options	Term to maturity (years)	December 31 2005 Carrying Value	2005 Fair Value	2004 Carrying Value	2004 Fair Value
			(in millions)			
Interest Rate Swaps						
Terasen Inc.	**3**	**1 - 9**	**$ —**	**$ 3.6**	$ —	$5.4
TGI	**3**	**2**	**—**	**(1.6)**	—	—
TGVI	**4**	**1 - 4**	**—**	**(0.6)**	—	(3.2)
Corridor	**2**	**5 - 10**	**—**	**0.3**	—	—
Natural Gas Commodity Swaps and Options						
TGI and TGVI	**161**	**Up to 3**	**21.2**	**105.6**	—	(8.3)
Clean Energy	**—**	**—**	**—**	**—**	6.5	6.5
Foreign Currency Swaps						
Terasen Inc.	**—**	**—**	**—**	**—**	(0.6)	(0.6)

The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

Included in the carrying value of the natural gas derivatives is $22.2 million of unrealized fair value gains associated with derivative instruments which were deemed to be ineffective at December 31, 2005, and $1.0 million of derivative instruments which did not qualify for hedge accounting that are in a liability position.

Clean Energy, an entity in which the Company held an interest, had historically purchased gas forward contract positions to offset future commodity supply contracts. Since these contracts were not specifically designated as hedges, these positions were marked-to-market at each balance sheet date and gains or losses were reported in the statement of earnings as cost of revenues from other activities. During the year ended December 31, 2005 the Company included in earnings an amount of $10.9 million (2004 — $3.3 million) net of tax and estimated selling expenses pertaining to the Company's proportionate share of Clean Energy's gas forward contracts.

The derivatives entered into by Terasen Gas and TGVI relate to regulated operations and any resulting gains or losses are recorded in rate stabilization accounts, subject to regulatory approval, and passed through to customers in future rates.

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Because it deals with high credit quality institutions in accordance with established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

17. COMMITMENTS & CONTINGENCIES

The Company's subsidiaries and proportionately consolidated entities have entered into operating leases for certain building space and natural gas distribution assets. In addition, Terasen Gas and TGVI have entered into gas purchase contracts which represent future purchase obligations.

The following table sets forth the Company's operating lease and gas purchase obligations due in the years indicated:

	Operating leases	Purchase obligations	Total
2006	$ 21.3	$ 873.8	$ 895.1
2007	20.2	113.6	133.8
2008	20.6	33.2	53.8
2009	19.3	30.2	49.5
2010	18.2	—	18.2
2011 and later	127.5	—	127.5
	$227.1	$1,050.8	$1,277.9

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at December 31, 2005.

In prior years, TGVI received non-interest bearing, repayable loans from the Federal and Provincial governments of $50 million and $25 million respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. The government loans are repayable in any fiscal year after 2002 and prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As approved by the BCUC, these loans have been recorded as a government grant and have reduced the amounts reported for property, plant and equipment. The Company anticipates that all of the repayment criteria may be met in 2006 and, if met, will result in an estimated repayment of $4.5 million of these loans in 2006. As the loans are repaid and replaced with non-governmental loans, plant and equipment and long-term debt will increase in accordance with the approved capital structure, as will the rate base used in determining rates. The amounts are not included in the obligations in the table above as the amounts and timing of

17. COMMITMENTS & CONTINGENCIES (CONTINUED)

repayments is dependent upon the approved RDDA recovery each year and the ability to replace the loans with non-government subordinated debt financing on reasonable commercial terms.

A number of claims and lawsuits seeking damages and other relief are pending against the Company. Management is of the opinion, based upon information presently available, that it is unlikely that any liability, to the extent not provided for through insurance or otherwise, would be material in relation to the Company's consolidated financial statements.

18. GUARANTEES

The Company has, for a fee, arranged for the issuance of a letter of credit in the amount of US$15.1 million on behalf of co-investors in the Express System to fund the Debt Service Reserve Account required under the Express System's trust indenture. The letter of credit is subject to annual renewal. If the letter of credit is drawn upon, the Company will have recourse to the co-investors, major Canadian pension funds.

The Company has, for a fee, provided indemnities with respect to performance bonds issued on behalf of Clean Energy in the amount of US$3.5 million. These performance bonds secure construction projects undertaken by Clean Energy, and expire at various dates before October 31, 2006.

The Company has letters of credit outstanding at December 31, 2005 totalling $118.5 million to support its operations and capital projects, including $50.8 million for its unfunded supplemental pension benefit plans and $17.6 million for the letter of credit referred to above on behalf of co-investors in the Express System.

19. SUBSEQUENT EVENTS

(a) On January 13, 2006, Terasen Gas (Vancouver Island) Inc. entered into a five-year unsecured, committed, revolving credit facility of $350 million with a syndicate of banks, of which $296 million was drawn against the facility on January 17, 2006. A portion of the facility was used to refinance TGVI's existing term facility of $209.5 million. The facility will also be utilized to finance working capital requirements and general corporate purposes.

Concurrently with executing the above noted facility, TGVI entered into a $20 million, seven-year unsecured, committed, non-revolving credit facility with one bank. This facility will be utilized for purposes of refinancing any annual prepayments TGVI may be required to make on non-interest bearing government contributions. The terms and conditions are primarily the same as the aforementioned TGVI facility except this facility ranks junior to repayment of TGVI's Class B subordinated debt which is held by the Company.

(b) On March 2, 2006 a Decision was issued by the BCUC approving changes to Terasen Gas' and TGVI's deemed equity components from 33% to 35% and from 35% to 40%, respectively, with effective from January 1, 2006. The same Decision also modified the previously existing generic return on equity (''ROE'') reset formula resulting in an increase in allowed ROE's from the levels that would have resulted from the old formula. The changes increased the allowed ROE for 2006 from 8.29% to 8.80% for Terasen Gas and from 8.79% to 9.50% for TGVI.

(c) Subsequent to year-end, the Company received a letter dated March 31, 2006 from the British Columbia Social Service tax authority indicating their intention to assess additional provincial sales tax on the Southern Crossing Pipeline which was completed in 2000. The letter received does not indicate the amount to be assessed and a formal notice of assessment has not been received. Any assessment will be appealed when it is received and the Company believes this assessment is without merit and it will not have a material adverse impact on the financial results of the Company.

Terasen Inc.

Unaudited Interim Consolidated Financial Statements
Three and nine months ended September 30, 2006

CONSOLIDATED STATEMENTS OF EARNINGS

(Unaudited)

	In millions of dollars			
	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Revenues				
Natural gas distribution	**$217.0**	$213.7	**$1,204.6**	$1,065.8
Petroleum transportation	**60.4**	57.3	**168.2**	163.0
Other activities	**10.9**	11.6	**33.3**	35.6
	288.3	282.6	**1,406.1**	1,264.4
Expenses				
Cost of natural gas	**108.4**	109.4	**767.4**	637.2
Cost of revenues from other activities	**6.0**	6.5	**21.0**	22.3
Operation and maintenance	**72.1**	68.7	**206.9**	201.3
Depreciation and amortization	**36.1**	35.3	**108.7**	106.0
Property and other taxes	**18.6**	18.0	**56.3**	53.8
	241.2	237.9	**1,160.3**	1,020.6
Operating income	**47.1**	44.7	**245.8**	243.8
Financing costs	**45.6**	44.1	**134.7**	132.9
Earnings before share of equity earnings and income taxes	**1.5**	0.6	**111.1**	110.9
Share of earnings (loss) from Clean Energy	**—**	(4.4)	**—**	2.2
Share of earnings from Express system	**5.8**	5.0	**16.2**	13.7
Earnings before income taxes and discontinued operations	**7.3**	1.2	**127.3**	126.8
Income taxes	**0.7**	0.3	**45.1**	31.9
Earnings before discontinued operations	**6.6**	0.9	**82.2**	94.9
Earnings (loss) from discontinued operations	**(4.1)**	3.1	**(17.0)**	4.9
Net earnings	**$ 2.5**	$ 4.0	**$ 65.2**	$ 99.8

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(Unaudited)

	Nine months ended September 30	
	2006	2005
	In millions of dollars	
Retained earnings, beginning of period	**$425.0**	$418.9
Net earnings	**65.2**	99.8
	490.2	518.7
Dividends on common shares	**—**	71.2
Retained earnings, end of period	**$490.2**	$447.5

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(Unaudited)

	In millions of dollars As at	
	September 30, 2006 (unaudited)	December 31, 2005
Assets		
Current assets		
Cash and short-term investments	**$ 82.8**	$ 79.4
Accounts receivable	**188.1**	468.1
Inventories of gas in storage and supplies	**249.7**	205.7
Prepaid expenses	**8.8**	14.1
Current portion of rate stabilization accounts	**142.5**	28.4
Current assets held for sale	**—**	54.8
	671.9	850.5
Property, plant and equipment	**3,994.8**	3,907.9
Long-term investment	**254.5**	238.3
Goodwill	**76.4**	76.4
Rate stabilization accounts	**49.8**	48.3
Other assets	**86.8**	84.8
Long-lived assets held for sale	**—**	109.9
	$5,134.2	$5,316.1
Liabilities and shareholder's equity		
Current liabilities		
Short-term notes	**$ 524.0**	$ 681.0
Accounts payable and accrued liabilities	**427.2**	433.8
Income and other taxes payable	**20.0**	30.8
Current portion of rate stabilization accounts	**—**	47.9
Current portion of long-term debt	**41.0**	398.2
Due to parent company	**6.3**	0.4
Current liabilities held for sale	**—**	24.5
	1,018.5	1,616.6
Long-term debt	**2,367.0**	2,012.9
Other long-term liabilities and deferred credits	**176.9**	168.5
Future income taxes	**71.7**	88.7
Long-term liabilities held for sale	**—**	13.7
	3,634.1	3,900.4
Shareholder's equity		
Common shares	**904.9**	904.9
Contributed surplus	**155.9**	137.5
Retained earnings	**490.2**	425.0
Cumulative currency translation adjustment	**0.1**	(0.7)
	1,551.1	1,466.7
Less cost of common shares held by Terasen Pipelines (Trans Mountain) Inc.	**51.0**	51.0
	1,500.1	1,415.7
	$5,134.2	$5,316.1

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
	In millions of dollars			
Cash flows provided by (used for)				
Operating activities				
Net earnings	**$ 2.5**	$ 4.0	**$ 65.2**	99.8
Adjustments for non-cash items				
Loss from discontinued operations	**4.1**	—	**17.0**	—
Depreciation and amortization	**36.1**	35.8	**108.7**	109.0
Share of equity earnings from long-term investments, in excess of cash distributions	**(5.8)**	(1.7)	**(16.2)**	(14.1)
Future income taxes	**(21.0)**	1.2	**(27.5)**	1.5
Other	**5.4**	8.5	**14.1**	11.5
	21.3	47.8	**161.3**	207.7
Change in rate stabilization accounts	**(19.2)**	(21.5)	**21.5**	2.0
Discontinued operations — water/utility services	**(4.1)**	—	**(17.0)**	—
Changes in working capital	**(50.7)**	(43.3)	**57.2**	(49.0)
	(52.7)	(17.0)	**223.0**	160.7
Investing activities				
Property, plant and equipment	**(84.1)**	(43.4)	**(194.2)**	(170.3)
Proceeds on the sale of water business	**8.3**	—	**132.6**	—
Other assets	**(2.2)**	(9.7)	**(3.9)**	(12.6)
	(78.0)	(53.1)	**(65.5)**	(182.9)
Financing activities				
Increase (decrease) in short-term notes	**148.0**	383.0	**(157.0)**	495.5
Increase in long-term debt	**127.1**	—	**407.8**	450.5
Reduction of long-term debt	**(99.8)**	(350.7)	**(410.8)**	(848.1)
Advances from KMI	**1.3**	—	**5.9**	—
Issue of common shares, net of issue costs	**—**	3.2	**—**	8.7
Dividends on common shares	**—**	(23.8)	**—**	(71.2)
	176.6	11.7	**(154.1)**	35.4
Net increase (decrease) in cash	**45.9**	(58.4)	**3.4**	13.2
Cash at beginning of period	**36.9**	91.6	**79.4**	20.0
Cash at end of period	**$ 82.8**	$ 33.2	**$ 82.8**	$ 33.2
Supplemental cash flow information				
Interest paid in the period	**$ 46.8**	$ 48.9	**$ 137.4**	$ 135.3
Income taxes paid in the period	**16.4**	22.7	**41.5**	48.0
Non-cash transaction				
Mark to market on certain gas derivatives deferred in rate stabilization accounts	**89.6**	—	**185.1**	—

Cash is defined as cash or bank indebtedness.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. BASIS OF PRESENTATION

The accounting policies and methods of application used in the preparation of these interim consolidated financial statements are consistent with the accounting policies used in the Company's year end audited consolidated financial statements of December 31, 2005. These consolidated financial statements do not include all disclosures required for annual financial statements, and therefore these statements should be read in conjunction with the consolidated financial statements for the year ended December 31, 2005. Certain comparative figures have been restated to conform with the current period presentation.

2. SEGMENT DISCLOSURES

	Three months ended September 30			
	Natural gas distribution	Petroleum transportation	Other activities	Total
	(in millions of dollars)			
2006				
Revenues	**$ 217.0**	**$ 60.4**	**$ 10.9**	**$ 288.3**
Earnings (loss) before discontinued operations	**(6.8)**	**17.4**	**(4.0)**	**6.6**
Net earnings (loss)	**(6.8)**	**17.4**	**(8.1)**	**2.5**
Total assets	**3,576.8**	**1,472.7**	**84.7**	**5,134.2**
2005				
Revenues	$ 213.7	$ 57.3	$ 11.6	$ 282.6
Earnings (loss) before discontinued operations	(3.6)	17.2	(12.7)	0.9
Net earnings (loss)	(3.6)	17.2	(9.6)	4.0
Total assets	3,428.3	1,364.5	299.0	5,091.8

	Nine months ended September 30			
	Natural gas distribution	Petroleum transportation	Other activities	Total
	(in millions of dollars)			
2006				
Revenues	**$1,204.6**	**$ 168.2**	**$ 33.3**	**$1,406.1**
Earnings (loss) before discontinued operations	**48.3**	**51.6**	**(17.7)**	**82.2**
Net earnings (loss)	**48.3**	**51.6**	**(34.7)**	**65.2**
Total assets	**3,576.8**	**1,472.7**	**84.7**	**5,134.2**
2005				
Revenues	$1,065.8	$ 163.0	$ 35.6	$1,264.4
Earnings (loss) before discontinued operations	59.8	50.8	(15.7)	94.9
Net earnings (loss)	59.8	50.8	(10.8)	99.8
Total assets	3,428.3	1,364.5	299.0	5,091.8

3. SEASONAL OPERATIONS

Due to the seasonal nature of the Company's natural gas distribution operations, quarterly earnings statements are not indicative of earnings on an annual basis.

4. RELATED PARTY TRANSACTIONS

The Company estimates that its parent company, Kinder Morgan Inc., provided management services totalling approximately $1.1 million (2005 — nil) for the three months ended September 30, 2006 and $8.5 million (2005 — nil) for the nine months ended September 30, 2006.

5. EMPLOYEE BENEFIT PLANS

The Company and its subsidiaries have defined benefit pension plans and defined contribution pension plans for employees. The Company also provides post-employment benefits other than pensions for retired employees. Additional information about these benefit plans can be found in the Company's 2005 Annual Report. The Company's estimated contributions to defined benefit pension plans for 2006 are anticipated to be $10.0 million (2005 actual $10.1 million).

Costs recognized in the periods are presented in the following tables:

	Three months ended September 30			
	Pension benefit plans		Other benefit plans	
	2006	2005	**2006**	2005
	(in millions of dollars)			
Current service cost	**$ 2.3**	$ 2.2	**$0.5**	$0.4
Interest cost on projected benefit obligations	**4.3**	4.5	**1.0**	1.0
Expected return on plan assets	**(5.2)**	(4.8)	**—**	—
Net actuarial losses	**(0.1)**	—	**—**	0.1
Plan amendments	**0.1**	0.2	**—**	—
Net benefit plan expense before adjustments of employee benefit costs:	**1.4**	2.1	**1.5**	1.5
Difference between actual and expected return on plan assets	**0.1**	0.1	**—**	—
Difference between actual and recognized actuarial gains in the year	**1.1**	0.6	**0.8**	0.3
Difference between actual and recognized past service	**0.2**	—	**—**	0.2
Amortization of transitional (benefit) obligation	**(0.8)**	(0.8)	**0.3**	0.4
Net benefit plan expense	**$ 2.0**	$ 2.0	**$2.6**	$2.4
Defined contribution plan expense	**$ 0.5**	$ 0.4		
Total pension expense	**$ 2.5**	$ 2.4		

	Nine months ended September 30			
	Pension benefit plans		Other benefit plans	
	2006	2005	**2006**	2005
	(in millions of dollars)			
Current service cost	**$ 7.0**	$ 6.6	**$1.5**	$1.2
Interest cost on projected benefit obligations	**12.9**	13.5	**3.1**	3.0
Expected return on plan assets	**(15.6)**	(14.4)	**—**	—
Net actuarial losses	**(0.4)**	—	**—**	0.3
Plan amendments	**0.3**	0.6	**—**	
Net benefit plan expense before adjustments of employee benefit costs:	**4.2**	6.3	**4.6**	4.5
Difference between actual and expected return on plan assets	**0.3**	0.3	**—**	—
Difference between actual and recognized actuarial gains in the year	**3.4**	1.8	**2.4**	0.9
Difference between actual and recognized past service	**0.6**	—	**—**	0.6
Amortization of transitional (benefit) obligation	**(2.5)**	(2.4)	**0.9**	1.2
Net benefit plan expense	**$ 6.0**	$ 6.0	**$7.9**	$7.2
Defined contribution plan expense	**$ 1.7**	$ 1.4		
Total pension expense	**$ 7.7**	$ 7.4		

6. CONTINGENCY AND COMMITMENTS

Terasen Gas, a subsidiary of the Company, received a Notice of Assessment dated July 31, 2006 from the British Columbia Social Service Tax authority for $37.1 million of additional provincial sales tax and interest on the Southern Crossing Pipeline, which was completed in 2000. This has not been provided for as the Company will appeal this assessment. Management believes that this assessment is without merit and will not have a material adverse impact on our business, financial position, results of operations or cash flows. In October 2006, the Company made a payment of $10 million pending resolution of the appeal as a good faith payment in order to forestall an order from the Province to provide full payment or security. The payment has been recorded as a long term receivable and a request for regulatory deferral account treatment has been made. This payment does not reflect Management's belief as to the ultimate sustainability of the assessment.

PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

FORTIS INC.

(Unaudited)

As at September 30, 2006 and for the nine-month period ended September 30, 2006 and the year ended December 31, 2005

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

The following unaudited *pro forma* consolidated financial statements give effect to the proposed acquisition (the ''Acquisition'') of Terasen Inc. (''Terasen'') under the purchase method of accounting. The unaudited *pro forma* consolidated balance sheet gives effect to the Acquisition as if it had occurred on September 30, 2006. The unaudited *pro forma* consolidated statements of earnings for the nine-month period ended September 30, 2006 and for the year ended December 31, 2005 give effect to the Acquisition as if it was completed on January 1, 2005.

These unaudited *pro forma* consolidated financial statements are presented for illustrative purposes only. The *pro forma* adjustments are based upon available information and certain assumptions that we believe are reasonable in the circumstances, as described in the notes to the unaudited *pro forma* consolidated financial statements.

Terasen is a holding company headquartered in Vancouver, British Columbia, operating two principal lines of business: natural gas distribution and petroleum transportation. Prior to the closing of the Acquisition, Kinder Morgan, Inc. (''Kinder Morgan'') will cause Terasen to divest itself of its petroleum transportation operations. These unaudited *pro forma* consolidated financial statements are based on Terasen's financial statements as at and for the nine months ended September 30, 2006 and for the year ended December 31, 2005. The financial position and results of the petroleum transportation operations have been excluded from the unaudited *pro forma* consolidated balance sheet and statements of earnings, respectively, by way of *pro forma* adjustments. Refer to Notes 2[b] and 2[d].

The *pro forma* information presented, including allocation of purchase price, is based on preliminary estimates of fair values of assets acquired and liabilities assumed, available information and assumptions and may be revised as additional information becomes available. The actual adjustments to our consolidated financial statements upon the closing of the Acquisition will depend on a number of factors, including additional information available and the net assets on the closing date of the Acquisition. Therefore, we believe that the actual adjustments will differ from the *pro forma* adjustments, and the differences may be material. For example, the final purchase price allocation is dependent on, among other things, the finalization of asset and liability valuations. A final determination of these fair values will reflect our consideration of a final valuation prepared by independent third-party appraisers. This final valuation will be based on the actual net tangible and intangible assets and liabilities that exist as of the closing date of the Acquisition. Any final adjustment may change the allocation of purchase price, which could affect the fair value assigned to the assets and liabilities and could result in a change to the unaudited *pro forma* consolidated financial statements, including a change to goodwill.

Fortis Inc.

PRO FORMA CONSOLIDATED BALANCE SHEET
As at September 30, 2006
(Unaudited)
($ millions)

	Fortis Inc.	Terasen Inc.	Note	*Pro forma* adjustments	*Pro forma* consolidated balance sheet
ASSETS					
Current					
Cash and cash equivalents	61.4	82.8		—	**144.2**
Accounts receivable	207.3	188.1	2[b]	(22.3)	**373.1**
Prepaid expenses	21.5	8.8	2[b]	(3.2)	**27.1**
Regulatory assets	29.3	142.5		—	**171.8**
Gas inventories, materials and supplies	25.6	249.7	2[b]	(3.2)	**272.1**
	345.1	671.9		(28.7)	**988.3**
Income tax deposit	5.9	—		—	**5.9**
Deferred charges and other assets	161.9	86.8	2[b]	(31.0)	**223.1**
			2[m]	3.0	
			2[n]	2.4	
Regulatory assets	103.4	49.8		—	**153.2**
Future income taxes	8.0	—	2[f]	8.4	**30.9**
			2[g]	14.5	
Utility capital assets	2,831.3	3,994.8	2[b]	(1,158.4)	**5,667.7**
Income producing properties	418.8	—		—	**418.8**
Investments	170.7	254.5	2[b]	(254.5)	**170.7**
Intangibles, net of amortization	10.9	—		—	**10.9**
Goodwill	550.9	76.4	2[b]	631.6	**1,258.9**
	4,606.9	5,134.2		(812.7)	**8,928.4**
LIABILITIES					
Current					
Short-term borrowings	70.7	524.0		—	**594.7**
Accounts payable and accrued charges	264.2	433.5	2[b]	(85.0)	**625.7**
			2[m]	3.0	
			2[l]	10.0	
Dividends payable	21.1	—		—	**21.1**
Income taxes payable	5.9	20.0	2[b]	2.2	**28.1**
Regulatory liabilities	25.5	—		—	**25.5**
Current installments of long-term debt and capital lease obligations	32.8	41.0		—	**73.8**
	420.2	1,018.5		(69.8)	**1,368.9**
Other long-term liabilities and deferred credits	77.2	176.9	2[b]	(16.8)	**237.3**
Regulatory liabilities	33.6	—		—	**33.6**
Future income taxes	46.9	71.7	2[b]	(63.5)	**55.1**
Long-term debt and capital lease obligations	2,254.0	2,367.0	2[b]	(300.0)	**4,484.3**
			2[e]	139.3	
			2[f]	24.0	
Non-controlling interest	50.4	—		—	**50.4**
Preference shares	319.5	—		—	**319.5**
	3,201.8	3,634.1		(286.8)	**6,549.1**
SHAREHOLDERS' EQUITY					
Common shares (i)	822.5	853.9	2[k]	(853.9)	**1,796.7**
			2[g]	1,001.0	
			2[g]	(26.8)	
Preference shares	122.5	—		—	**122.5**
Contributed surplus	4.3	155.9	2[k]	(155.9)	**4.3**
Equity portion of convertible debentures	1.4	—		—	**1.4**
Foreign currency translation adjustment	(17.8)	0.1	2[k]	(0.1)	**(17.8)**
Retained earnings	472.2	490.2	2[k]	(490.2)	**472.2**
	1,405.1	1,500.1		(525.9)	**2,379.3**
	4,606.9	5,134.2		(812.7)	**8,928.4**

(i) Terasen Inc. common shares are net of $51.0 million of shares held by its wholly owned subsidiary, Terasen Pipelines (Trans Mountain) Inc.

See accompanying notes

Fortis Inc.

PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS
For the year ended December 31, 2005
(Unaudited)
($ millions, except for per share amounts)

	Fortis Inc.	Terasen Inc.	*Pro forma* adjustments Note		*Pro forma* consolidated statement of earnings
Operating revenues	1,430.0	1,952.5	2[d]	(227.8)	**3,154.7**
Equity income	11.4	24.4	2[d]	(21.9)	**13.9**
	1,441.4	1,976.9		(249.7)	**3,168.6**
Expenses					
Energy supply	533.9	1,063.7		—	**1,597.6**
Operating	392.4	421.5	2[d]	(106.9)	**707.0**
Amortization	157.6	142.6	2[d]	(37.6)	**263.2**
			2[m]	0.6	
	1,083.9	1,627.8		(143.9)	**2,567.8**
Operating income	357.5	349.1		(105.8)	**600.8**
Finance charges	153.8	191.4	2[d]	(31.7)	**323.2**
			2[e]	7.3	
			2[o]	(5.8)	
			2[n]	1.0	
			2[p]	7.2	
Gain on settlement of contractual matters	(10.0)	—		—	**(10.0)**
	143.8	191.4		(22.0)	**313.2**
Earnings before income taxes, non-controlling interest and discontinued operations	213.7	157.7		(83.8)	**287.6**
Income taxes	70.4	51.6	2[d]	(9.0)	**111.9**
			2[i]	(1.1)	
Earnings before non-controlling interest and discontinued operations	143.3	106.1		(73.7)	**175.7**
Non-controlling interest	6.2	—		—	**6.2**
Earnings before discontinued operations	137.1	106.1		(73.7)	**169.5**
Loss from discontinued operations	—	4.9		—	**4.9**
Net earnings applicable to common shares	137.1	101.2		(73.7)	**164.6**
Average common shares outstanding (number, in millions)	101.8		2[g]	38.5	**140.3**
Earnings per common share before discontinued operations					
Basic	$ 1.35				**$ 1.21**
Diluted	$ 1.24				**$ 1.15**
Earnings per common share					
Basic	$ 1.35				**$ 1.17**
Diluted	$ 1.24				**$ 1.12**

See accompanying notes

Fortis Inc.

PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS
For the nine-month period ended September 30, 2006

(Unaudited)

($ millions, except for per share amounts)

	Fortis Inc.	Terasen Inc.	*Pro forma* Adjustments Note		*Pro forma* consolidated statement of earnings
Operating revenues	1,071.7	1,406.1	2[d]	(168.2)	**2,309.6**
Equity income	6.9	16.2	2[d]	(16.2)	**6.9**
	1,078.6	1,422.3		(184.4)	**2,316.5**
Expenses					
Energy supply	394.0	767.4		—	**1,161.4**
Operating	290.3	284.2	2[d]	(74.3)	**500.2**
Amortization	130.9	108.7	2[d]	(28.1)	**212.0**
			2[m]	0.5	
	815.2	1,160.3		(101.9)	**1,873.6**
Operating income	263.4	262.0		(82.5)	**442.9**
Finance charges	124.4	134.7	2[d]	(20.1)	**246.2**
			2[e]	5.5	
			2[o]	(4.4)	
			2[n]	0.7	
			2[p]	5.4	
Gain on sale of income producing properties	(2.1)	—		—	**(2.1)**
	122.3	134.7		(12.9)	**244.1**
Earnings before income taxes, non-controlling interest and discontinued operations	141.1	127.3		(69.6)	**198.8**
Income taxes	23.1	45.1	2[d]	(10.3)	**57.1**
			2[i]	(0.8)	
Earnings before non-controlling interest and discontinued operations	118.0	82.2		(58.5)	**141.7**
Non-controlling interest	4.7	—		—	**4.7**
Earnings before discontinued operations	113.3	82.2		(58.5)	**137.0**
Loss from discontinued operations	—	17.0		—	**17.0**
Net earnings applicable to common shares	113.3	65.2		(58.5)	**120.0**
Average common shares outstanding (number, in millions)	103.5		2[g]	38.5	**142.0**
Earnings per common share before discontinued operations					
Basic	$ 1.09				**$ 0.96**
Diluted	$ 1.05				**$ 0.94**
Earnings per common share					
Basic	$ 1.09				**$ 0.85**
Diluted	$ 1.05				**$ 0.84**

See accompanying notes

NOTES TO PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited *pro forma* consolidated financial statements give effect to the acquisition (the ''Acquisition'') of all of the issued and outstanding shares in Terasen Inc. (''Terasen'') as described in the short form prospectus dated March 7, 2007 (the ''Prospectus''). The accompanying unaudited *pro forma* consolidated financial statements have been prepared by management of Fortis Inc. (''Fortis'' or the ''Corporation'') and are derived from the unaudited and audited consolidated financial statements of Fortis as at and for the nine-month period ended September 30, 2006 and for the year ended December 31, 2005, respectively; and the unaudited and audited financial statements of Terasen as at and for the nine-month period ended September 30, 2006, and for the year ended December 31, 2005, respectively.

The accounting policies used in the preparation of these unaudited *pro forma* consolidated financial statements are those disclosed in the Corporation's audited financial statements. Management has determined that no adjustments to Terasen's financial statements are required to comply with the accounting policies used by Fortis in the preparation of its consolidated financial statements. Certain accounting policies followed by Terasen are different from that of Fortis due to rate regulation associated with a gas utility imposed by the British Columbia Utilities Commission (''BCUC'').

As is standard with similar transactions in regulated utilities, the purchase price is primarily based upon the regulated assets at the point of closing. Based on the purchase price calculation as detailed in the acquisition agreement dated February 26, 2007 (the ''Acquisition Agreement''), the estimated net purchase price of Terasen is $1,099.0 million (refer to Note 2[a]).

The unaudited *pro forma* consolidated balance sheet and unaudited *pro forma* consolidated statements of earnings reflect the acquisition effected on September 30, 2006 and January 1, 2005, respectively. The unaudited *pro forma* consolidated financial statements are not necessarily indicative of the results that actually would have been achieved if the transactions reflected therein had been completed on the dates indicated or the results which may be obtained in the future. For instance, the actual purchase price allocation will reflect the fair value, at the purchase date, of the assets acquired and liabilities assumed based upon the acquirer's evaluation of such assets and liabilities following the closing of the transaction and, accordingly, the final purchase price allocation, as it relates principally to intangible assets, may differ significantly from the preliminary allocation reflected herein.

These unaudited *pro forma* consolidated financial statements should be read in conjunction with the description of the transaction described in the Prospectus; the audited and unaudited financial statements of Terasen, including the notes thereto, included in the Prospectus; and the audited and unaudited consolidated financial statements of Fortis including the notes thereto, incorporated by reference in the Prospectus.

The underlying assumptions for the *pro forma* adjustments provide a reasonable basis for presenting the significant financial effect directly attributable to the Acquisition. These *pro forma* adjustments are tentative and are based on available financial information and certain estimates and assumptions. The actual adjustments to the consolidated financial statements will depend on a number of factors. Therefore, we believe that the actual adjustments will differ from the *pro forma* adjustments, and the differences may be material.

2. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS

[a] These *pro forma* consolidated financial statements give effect to the completion of the Acquisition, as if it had occurred on September 30, 2006 in respect of the *pro forma* consolidated balance sheet, and on January 1, 2005 in respect of the *pro forma* consolidated statements of earnings for the year ended December 31, 2005 and for the nine-month period ended September 30, 2006. The Acquisition has been reflected in the *pro forma* consolidated financial statements using the purchase method.

Estimated Net Purchase Price

	($ millions)
Unadjusted purchase price	1,801.0
Estimated acquisition costs (Note 2[h])	25.0
Estimated net purchase price, before assumed debt	1,826.0
Assumed cash of Terasen in excess of normal working capital	40.0
Assumed short-term notes of Terasen (Note 2[f])	(317.0)
Assumed long-term debt of Terasen (Note 2[f])	(450.0)
Estimated net purchase price	1,099.0

Estimated Net Funding Requirements

	($ millions)
Estimated net purchase price	1,099.0
Assumed short-term notes of Terasen	317.0
Assumed long-term debt of Terasen	450.0
Common share issuance costs (Note 2[g])	41.3
Estimated net funding requirements	1,907.3

Assumed Financing Structure

	($ millions)
Assumed short-term notes of Terasen	317.0
Assumed long-term debt of Terasen	450.0
Common share issuance (Note 2[g])	1,001.0
Incremental long-term debt issuance (Note 2[e])	139.3
	1,907.3

[b] Petroleum Transportation segment net assets and allocation of estimated net purchase price

The estimated net purchase price has been allocated to the fair values of Terasen net assets and liabilities at September 30, 2006, excluding the net assets and liabilities of the petroleum transportation segment which are not being acquired, in accordance with the purchase method, as follows:

	($ millions)				
	Terasen Inc.	Petroleum Transportation	Note	Fair Value and Other Adjustments	Net Total
Assets acquired:					
Cash and cash equivalents	82.8	—		—	**82.8**
Accounts receivable	188.1	(22.3)		—	**165.8**
Prepaid expenses	8.8	(3.2)		—	**5.6**
Regulatory assets	142.5	—		—	**142.5**
Gas inventories, materials and supplies	249.7	(3.2)		—	**246.5**
Current assets	**671.9**	**(28.7)**		—	**643.2**
Deferred charges and other assets	86.8	(31.0)	2[n]	2.4	**58.2**
Regulatory assets	49.8	—		—	**49.8**
Future income taxes	—	—	2[f]	8.4	**8.4**
Utility capital assets	3,994.8	(1,158.4)		—	**2,836.4**
Investments	254.5	(254.5)		—	**—**
Intangibles	—	—		—	**—**
	5,057.8	**(1,472.6)**		10.8	**3,596.0**
Liabilities assumed:					
Short-term borrowings	524.0	—		—	**524.0**
Accounts payable and accrued charges	433.5	(85.0)	2[l]	10.0	**358.5**
Income taxes payable	20.0	2.2		—	**22.2**
Current installments of long-term debt and capital lease obligations	41.0	—		—	**41.0**
Other long-term liabilities and deferred credits	176.9	(16.8)		—	**160.1**
Future income taxes	71.7	(63.5)		—	**8.2**
Long-term debt and capital lease obligations	2,367.0	(300.0)	2[f]	24.0	**2,091.0**
	3,634.1	**(463.1)**		34.0	**3,205.0**
Net assets at fair value, as at September 30, 2006	1,423.7	(1,009.5)		(23.2)	**391.0**
Net purchase price					**1,099.0**
Goodwill					**708.0**
Goodwill previously recorded by Terasen					**(76.4)**
Additional goodwill					**631.6**

Terasen's natural gas distribution business is regulated under traditional cost of service. The determination of revenues and earnings is based on regulated rates of return that are applied to historic values and does not change with a change of ownership. Therefore, for the regulated business, no fair market value adjustments are recorded as part of the purchase price on individual assets and liabilities, including intangibles, to be acquired, because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. The book value of the assets and liabilities of the regulated business to be acquired has been assigned as fair value for the purchase price allocation.

[c] Goodwill

The excess of the purchase price, including estimated fees and expenses related to the Acquisition, over the preliminary fair value of net assets acquired from Terasen is classified as goodwill on the accompanying *pro forma* consolidated balance sheet.

[d] Results of Petroleum Transportation segment

The acquisition of Terasen does not include the petroleum transportation segment and, as such, the results of this segment for the year ended December 31, 2005 and for the nine months ended September 30, 2006 have been excluded, as follows:

	($ millions)	
	Nine-month period ended Sept 30, 2006	Year ended December 31, 2005
Operating revenues	168.2	227.8
Equity income	16.2	21.9
	184.4	249.7
Expenses		
Operating	74.3	106.9
Amortization	28.1	37.6
Finance charges	20.1	31.7
Income taxes	10.3	9.0
	132.8	185.2

[e] Financing

The Corporation has entered into a bridge financing agreement with its bankers at an assumed rate of 5.10%. This bridge will be refinanced with the issuance of other permanent capital including long-term debt facilities. It is assumed the anticipated debt funding requirement of $139.3 million will be initially financed by the bridge acquisition facility and will be subsequently refinanced at an average rate of 5.25%.

Additional interest expense of the following has been assumed:

	($ millions)	
	Nine-month period ended Sept 30, 2006	Year ended December 31, 2005
Interest on $139.3 million of refinanced incremental debt at 5.25%	5.5	7.3

[f] Assumed debt

Terasen has long-term debt outstanding of $450.0 million, in various series with due dates ranging from 2008 to 2040. The rates range from 5.56% to 8.0%, resulting in the fair market value of the debt exceeding book value by $24.0 million, ($15.6 million, net of future income taxes of $8.4 million), calculated as at September 30, 2006. No adjustment was made to the carrying value of the debt securities of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. This is due to the rate regulated nature of their businesses in which recovery in rates of the costs related to these debt securities is subject to the regulation of the BCUC.

Terasen also has short-term notes of $317.0 million that are being assumed. The remaining short-term notes balance of $207.0 million relates to the BCUC regulated business.

[g] Common share issuance

To fund a portion of the Acquisition purchase price, the Corporation plans to issue approximately 38.5 million common shares on closing resulting in estimated gross proceeds of $1,001.0 million, or net proceeds after common share issuance costs of $974.2 million ($41.3 million common share issuance costs less $14.5 million of future income taxes). The price of $26.00 per share, being the offering price for the issuance of 38.5 million subscription receipts of the Corporation pursuant to the Prospectus dated March 7, 2007, has been used as the issue price per share in the *pro forma* consolidated financial statements.

[h] Acquisition costs

It is assumed Acquisition costs will approximate $25.0 million, and will form part of the investment cost base. These primarily relate to investment banking and legal fees.

[i] Income taxes

Income taxes applicable to the *pro forma* adjustments are tax effected at Fortis' average tax rates of 35.0% and 35.0% for the year ended December 31, 2005 and the nine-month period ended September 30, 2006, respectively.

[j] Earnings per common share

The calculation of the *pro forma* earnings per common share for the year ended December 31, 2005, and for the nine-month period ended September 30, 2006, considers the issuance of 38.5 million common shares as contemplated in the Prospectus dated March 7, 2007, as if the issuance had taken place as at January 1, 2005.

[k] Terasen historical shareholder's equity balances

The historical shareholder's equity, contributed surplus, foreign currency translation and retained earnings balances of Terasen have been eliminated.

[l] Transition costs

Estimated known restructuring costs of $10.0 million are related to an after-tax estimate of expenses associated with a transition plan. The assessment of this plan will be completed as soon as possible after the consummation of the Acquisition and actions under the plan will begin as soon as possible thereafter.

[m] Long-term debt financing costs

Long-term debt financing costs are assumed to approximate $3.0 million, and will be deferred and amortized over the estimated term of the long-term debt of five years.

[n] Fair value of interest rate swaps and related amortization

The fair value of interest rate swaps of Terasen is an asset of $2.4 million as at September 30, 2006. The fair value adjustment will be amortized over the term of the related debt.

[o] Amortization of fair value debt adjustment

The debt fair value adjustment will be amortized over the term of the related debt. Refer to Note 2[f].

[p] Segmentation of short-term interest expense

The $317 million of assumed short-term notes of Terasen includes $110 million which had previously been allocated to the petroleum transportation segment by Terasen. With the acquisition of Terasen and the removal of the petroleum transportation segment, interest on the $110 million of short-term notes has been reallocated back to the remaining business being acquired as follows:

($ millions)	
Nine-month period ended Sept 30, 2006	Year ended December 31, 2005
5.4	7.2

INDEX TO MANAGEMENT DISCUSSION AND ANALYSIS

Terasen Inc.

2005 Management Discussion and Analysis
For the Year Ended December 31, 2005
April 10, 2006

This discussion should be read in conjunction with the consolidated financial statements of the Company and related notes for the years ended December 31, 2005 and 2004. In this MD&A, we, us, our, the Company and Terasen mean Terasen Inc., its subsidiaries, joint ventures and investments in significantly influenced companies. Terasen Gas refers to Terasen Gas Inc., TGVI refers to Terasen Gas (Vancouver Island) Inc., Trans Mountain refers to Terasen Pipelines (Trans Mountain) Inc., Corridor refers to Terasen Pipelines (Corridor) Inc., Terasen Pipelines refers to Terasen Pipelines Inc., Express refers to the Express and Platte Pipeline Systems; and Water and Utility Services refers to Terasen Waterworks (Supply) Inc., Terasen Utility Services Inc. and Terasen's 50% interest in Fairbanks Sewer and Water Inc. KMI refers to Kinder Morgan, Inc.

The financial data included in this discussion has been prepared in accordance with Canadian generally accepted accounting principles, and all dollar amounts are in Canadian dollars unless otherwise stated.

About Terasen

On November 30, 2005, all of the shares of the Company were acquired by Kinder Morgan, Inc. (''KMI''), through a subsidiary, pursuant to a Combination Agreement dated as of August 1, 2005. The Company's shareholders were able to elect, for each Terasen share held, either (i) $35.75 in cash, (ii) 0.3331 shares of KMI common stock, or (iii) $23.25 in cash plus 0.1165 shares of KMI common stock. In the aggregate, approximately 12.5 million shares of KMI common stock was issued together with cash payments of approximately $2.49 billion to Terasen securityholders.

Natural Gas Distribution

Terasen's natural gas distribution operations consist primarily of Terasen Gas and TGVI in addition to several small related utility operations. Terasen Gas is the largest distributor of natural gas in British Columbia, serving more than 804,000 customers in more than 100 communities. Major areas served by Terasen Gas are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of the province. TGVI serves approximately 85,000 customers on Vancouver Island and the Sunshine Coast area and Terasen Gas (Whistler) serves approximately 2,000 customers in the Whistler region. Terasen Gas and TGVI provide transmission and distribution services to their customers, and obtain natural gas supplies on behalf of residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through the Company's Southern Crossing Pipeline, from Alberta.

Petroleum Transportation

Terasen's petroleum transportation operations are the Trans Mountain, Corridor, Express and Platte pipelines. These operations are conducted under the Kinder Morgan Canada name. Trans Mountain transports crude oil and refined products from Edmonton, Alberta to Burnaby, British Columbia and also delivers Canadian crude oil to several refineries in Washington State. Trans Mountain also owns the Westridge Marine Terminal, which is located at tidewater in the Port of Vancouver, and a jet fuel pipeline connecting to Vancouver International Airport. Corridor owns a dual pipeline system which transports diluted bitumen and diluent between the Muskeg River mine near Fort McMurray and the Shell upgrader north of Edmonton, Alberta. Corridor commenced commercial operations in May 2003. Terasen also owns a one-third interest in the Express Pipeline and the Platte Pipeline which transports crude oil from Hardisty, Alberta to the Rocky Mountain region of the United States and on to Wood River, Illinois.

Other Activities

In addition to Terasen's core businesses of Natural Gas Distribution and Petroleum Transportation, Terasen owns interests in several smaller businesses including a 30% interest in CustomerWorks LP. CustomerWorks provides billing and customer care services to utilities, municipalities and retail energy companies. CustomerWorks has outsourced the provision of its customer care services to an entity owned and operated by Accenture Inc. Prior to the disposition of Terasen's 40.4% ownership interest in Clean Energy on October 31, 2005, the other activities segment also included Clean Energy Fuel Corp. (''Clean Energy''), a provider of natural gas vehicle refueling infrastructure.

In January 2006, Terasen entered into a Purchase and Sale Agreement to dispose of its interest in its water and utility services operations for proceeds of approximately $125 million. The disposition is expected to be completed by the end of April 2006, subject to regulatory approvals. The water and utility services business has accordingly been reclassified as assets and liabilities held for sale and as discontinued operations. The disposition is not expected to give rise to a material gain or loss.

Results of Operations

Net Earnings

	Years ended December 31	
	2005	2004
	(in millions of dollars)	
Natural gas distribution		
Terasen Gas	**$ 65.3**	$ 69.7
TGVI	**25.5**	26.2
	90.8	95.9
Petroleum transportation		
Trans Mountain	**25.4**	39.4
Corridor	**13.6**	15.6
Express System	**25.5**	15.9
	64.5	70.9
Discontinued operations	**(4.9)**	3.3
Other activities	**(49.2)**	(20.3)
Net earnings	**$101.2**	$149.8

Net earnings for 2005 decreased by $48.6 million compared to 2004. Significant items that impacted net earnings in 2005 were as follows:

Certain items

	($ millions)
KMI transaction costs	$42.9
Inland Pacific Connector costs	3.6
Clean Energy hedging gains and disposition costs	(2.5)
Premium on Trans Mountain debt redemption	7.3
	$51.3

In 2005 the Company has charged to earnings after-tax costs of $42.9 million associated with the acquisition by KMI, mainly from pre-tax investment banking costs of $14.7 million, severance and employee-related costs of $14.4 million, share option costs of $3.6 million, and the write-off of approximately $15.3 million of income tax expense related to restricted tax loss carry-forwards.

In the fourth quarter of 2005 Terasen Gas expensed $3.6 million (after-tax) of costs incurred in connection with the Inland Pacific Connector project that were not permitted recovery in rates by the BCUC.

On October 31, 2005, the Company sold its 40.4% ownership in Clean Energy for proceeds of approximately U.S. $35.9 million. The sale, together with equity earnings of Clean Energy for the ten months ended October 31, 2005, has resulted in a gain of approximately $2.5 million, including the recognition of all unrealized gas forward contract gains of Clean Energy in 2005 totalling $10.9 million and the recognition of currency translation losses previously included in Shareholders' Equity totalling $8.4 million.

On November 1, 2005, Trans Mountain exercised its right to redeem the $35 million Series C Debentures. An after-tax charge to earnings of $7.3 million was incurred in connection with the premium that was paid to redeem the debentures.

The water and utility services business operations earnings have been reclassified to discontinued operations for both 2005 and 2004.

Selected Annual Information

	Years ended December 31		
	2005	2004	2003
	(in millions of dollars)		
Total revenues[1]	**$1,952.5**	$1,798.1	$1,763.1
Net income before discontinued operations[1]	**106.1**	146.5	130.7
Net income[2]	**101.2**	149.8	132.7
Common dividends paid	**95.1**	86.4	79.4
Total assets (restated)[1]	**5,316.1**	4,981.8	4,933.1
Long-term debt[1,3]	**2,012.9**	2,291.6	2,426.1
Current portion of long-term debt	**398.2**	416.7	51.8

1. Total revenues in 2004 and 2003 have been restated to reflect the reclassification of the water and utility services business as discontinued operations. Net income before discontinued operations and long-term debt for 2004 and 2003 have been restated for the reclassification of the Company's capital securities from equity to long-term debt, and the reclassification of the respective financing costs and income taxes. Total assets for 2004 and 2003 have been restated to reflect the reclassification of deferred charges to other long-term liabilities and deferred credits.

2. Terasen is a wholly-owned subsidiary of KMI and accordingly earnings per share information is not disclosed.

3. Excluding current portion of long-term debt.

Growth in total revenues has been caused mainly by higher natural gas commodity prices, particularly in 2005, which are flowed through in customer rates. Net income, when adjusted for the KMI transaction costs and Trans Mountain Series C redemption costs in 2005, has grown since 2003 mainly as a result of strong earnings growth in petroleum transportation. The completion of the Corridor Pipeline project in April 2003 and the Express System expansion in 2005 and throughput growth on the Trans Mountain system have been the main contributors to earnings growth. The increase in total assets from 2004 to 2005 reflected both capital expenditures and growth in natural gas inventories and accounts receivable as a result of higher natural gas commodity prices.

Results by Business Segment

Natural Gas Distribution

	Years ended December 31	
	2005	2004
	(in millions of dollars)	
Natural gas distribution revenues	**$1,678.0**	$1,494.1
Natural gas distribution net earnings	**90.8**	95.9

Revenues from natural gas distribution increased in 2005 compared to 2004 mainly as a result of higher market prices for natural gas, which are flowed through in customer rates. Cost of natural gas increased by a corresponding amount.

Earnings from natural gas distribution declined from $95.9 million in 2004 to $90.8 million in 2005 related to the expensing of costs associated with the KMI acquisition and the expensing of costs associated with the Inland Pacific Connector project, as well as a lower allowed return on equity in both Terasen Gas and TGVI and reduced earnings from accretion of the RDDA acquisition discount in TGVI. These factors were partially offset by strong operating performance in both Terasen Gas and TGVI as discussed below.

TERASEN GAS

Earnings from Terasen Gas decreased from $69.7 million to $65.3 million due to the expensing of $6.4 million of costs related to the KMI acquisition primarily from the expiry of loss carryforwards due to the change in control, a lower allowed return on equity in 2005 compared to 2004, and the expensing of $3.6 million (after-tax) of costs incurred in connection with the Inland Pacific Connector project that were not permitted recovery in rates by the BCUC. These factors were partially offset by strong operating performance, including higher transportation revenue, rate base growth and reduced bad debt expense.

Terasen Gas net customer additions during 2005 were 12,613, up from 11,750 customer additions in 2004. Solid economic conditions and continued strength in new housing starts in British Columbia helped drive the net customer additions in 2005. Terasen Gas industrial sales volumes decreased by 755 terajoules while transportation volumes increased by 1,113 terajoules from the previous year. Terasen Gas earns approximately the same margin regardless of whether a customer contracts for sales or transportation service.

Regulation

Terasen Gas' rates are based on estimates of several items, such as natural gas sales volumes, cost of natural gas, and interest rates. In order to manage the risks associated with some of these estimates, a number of regulatory deferral accounts are in place.

Two mechanisms to ameliorate unanticipated changes in sales volumes, such as changes caused by weather, have been implemented specifically for Terasen Gas. The first, originally called the Gas Cost Reconciliation Account (GCRA), relates to the recovery of all gas costs through a deferral account which captures all variances (overages and shortfalls) from forecasts. Balances are either refunded to or recovered from customers via an application with the BCUC. Creation of the GCRA was approved by the BCUC in October 1993; effective April 2004 the GCRA was split into two new deferral accounts called the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA). The CCRA and MCRA were created to support commodity unbundling and the refund/recovery mechanism works the same as that used for the GCRA. The second mechanism seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism (RSAM).

The RSAM and CCRA/MCRA accounts reduce Terasen Gas' earnings exposure to related risks by deferring any variances between projected and actual gas consumption and gas costs, and refunding or recovering those variances in rates in subsequent periods. Variances in usage by large volume, industrial transportation and sales customers are not covered by these deferral accounts as their usage is more predictable and less likely to be significantly affected by weather.

In 2005, the net balances of the RSAM and CCRA/MCRA accounts decreased to a payable of $9.0 million from a receivable of $14.1 million in 2004. In order to ensure that the balances in the CCRA/MCRA account are recovered on a timely basis, Terasen Gas prepares and files quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas costs.

Short-term and long-term interest rate deferral accounts are also in place to absorb interest rate fluctuations. The interest rate deferral accounts which were in place during 2004 effectively fixed the interest expense on short-term funds attributable to Terasen Gas' regulated assets at 4.00% during 2005, up from 3.25% in 2004. The effective fixed short-term interest rate for 2006 has been set at 4.00%. Any variations from this rate throughout the year are recorded in deferral accounts.

Allowed Return on Equity (ROE) and Capital Structure

Terasen Gas' allowed ROE is determined annually based on a formula that applies a risk premium to a forecast of long-term Government of Canada bond yields. For 2005, the application of the ROE formula set Terasen Gas' allowed ROE at 9.03%, down from 9.15% in 2004. Terasen Gas and TGVI applied to the BCUC in June 2005 to increase their deemed equity components from 33% to 38% and from 35% to 40%, respectively. The same application also requested an increase in allowed ROEs from the levels that would have resulted from the historic formula, which would have been 8.29% for Terasen Gas and 8.79% for TGVI in 2006.

The BCUC rendered its decision on the application on March 2, 2006, to be effective as of January 1, 2006. The generic ROE formula for a benchmark utility in British Columbia was changed such that it will be reset annually off a forecast of 30 Year Canada Bonds plus a 3.90% risk premium when the forecast yield on 30 Year Canada Bond is 5.25% The risk premium is adjusted annually by 75% of the difference between 5.25% and the forecast yield on 30 Year Canada Bonds. The changes increased the allowed ROE from 8.29% to 8.80% for Terasen Gas and from 8.79% to 9.50% for TGVI in 2006. The Decision also resulted in increases in the deemed equity components of Terasen Gas and TGVI to 35% and 40%, respectively.

2004-2007 Performance Based Rate Plan (PBR)

In July 2003, Terasen Gas received BCUC approval of a negotiated settlement for a 2004-2007 PBR. The PBR Settlement establishes a process for determining Terasen Gas' delivery charges and incentive mechanisms for improved operating efficiencies. The four-year agreement includes incentives for Terasen Gas to operate more efficiently through the sharing of the benefits between Terasen Gas and its customers. The PBR Settlement includes ten service quality measures designed to ensure Terasen Gas maintains service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between Terasen Gas and interested parties regarding its current performance and future activities.

Operation and maintenance costs and base capital expenditures are subject to an incentive formula reflecting increasing costs due to customer growth and inflation, less an adjustment factor based on 50 percent of inflation during the first two years of the PBR and 66 percent of inflation during the last two years. Base capital expenditure amounts are a function of customer numbers and projected customer additions. The PBR Settlement provides for a 50/50 sharing mechanism of earnings above or below the allowed return on equity beginning in 2004.

Upon expiry of the 2004-2007 PBR, there is no certainty as to whether a new negotiated settlement will be entered into, or what the terms of a new settlement might be.

Municipal Leasing Transactions
Certain municipalities in Terasen Gas' service area have an option to purchase the gas distribution franchise within their municipal boundary. In order to address these purchase options, the Company has developed a leasing arrangement that allows Terasen Gas to continue to operate the gas distribution assets by effectively selling the assets to the municipality and leasing them back for a 17 year period. After 17 years, Terasen Gas has an option to repurchase the assets at depreciated value. At December 31, 2005, Terasen Gas had entered into transactions involving a total value of $152.7 million, and the value of future transactions is not expected to be material.

TGVI
Earnings from TGVI remained steady, decreasing only slightly from $26.2 million to $25.5 million.

TGVI net customer additions during 2005 were 4,354, up from 4,233 customer additions in 2004.

Regulation
TGVI is also regulated by the BCUC. In 1995, an agreement was entered into between TGVI, the Province of British Columbia (the Province) and the Government of Canada, which included a Special Direction that was issued to the BCUC. The agreement, which expires no sooner than December, 2011, includes the following terms:

- TGVI receives, for the benefit of its customers, an annual payment until 2011 from the Province based on the wellhead price of natural gas in B.C. This payment amounted to $46.7 million in 2005, up from $33.2 million in 2004.
- The accumulated revenue deficiency resulting from overall revenues being below the cost of service prior to 2003 had been recorded in a Revenue Deficiency Deferral Account (RDDA). When Terasen acquired TGVI, the amount of the RDDA was $85 million, for which Terasen paid a price of $61 million. The accumulated RDDA recorded on Terasen's consolidated financial statements totaled $35.2 million as at December 31, 2005, corresponding to a balance for TGVI regulatory purposes of $48.3 million. The balance on Terasen's consolidated financial statements is down $10.4 million from December 31, 2004. Terasen is committed to fund these revenue deficiencies by purchasing preferred shares or subordinated debt issued by TGVI. The BCUC was directed to set rates beginning in 2003 that amortize the RDDA balance over the shortest period reasonably possible, having regard for TGVI's competitive position relative to alternative energy sources and the desirability of reasonable rates. The earnings impact of the RDDA discount is discussed under Results — Natural Gas Distribution.
- Any variances in the achieved ROE in a particular year from the allowed ROE (other than variances resulting from operation and maintenance costs) are deferred and recorded in the RDDA. The RDDA accumulated by TGVI is funded by the Company. Recovery of the deficiency through rates charged to customers is dependent upon regulatory approval and must be balanced against maintaining the competitiveness of TGVI's service relative to alternative energy sources. As a result, most risks associated with TGVI's annual financial results (other than operating costs) are, subject to BCUC approval, transferred to customers through the RDDA. The Company began recovery of the deficiency in 2003.

TGVI renewed its regulatory settlement in late 2005 for a two-year period effective January 1, 2006. It provides for a continuation of the operation and maintenance cost incentive arrangements previously in place. The allowed ROE for TGVI was 9.53% for 2005, compared to 9.65% in 2004. As described above, TGVI's ROE for 2006 is 9.50% and TGVI's deemed equity component of its capital structure for 2006 is 40%.

To ensure prompt recovery of the RDDA, the BCUC has approved a rate-setting mechanism for TGVI whereby customer rates are set at levels in excess of TGVI's cost of service, but effectively capped by the price of competitive alternative fuels (electricity or heating oil). This has resulted in significant RDDA amortization in both 2004 and 2005. However, RDDA recovery is sensitive to the relative pricing of natural gas and electricity in TGVI's service area, as well as to margin generated under TGVI's firm transportation agreements discussed below. There is no certainty that TGVI will be able to charge rates that will be sufficient to fully recover the RDDA prior to the expiry of the Provincial royalty payments at the end of 2011.

Contractual Arrangements

During 2005 TGVI's firm transportation agreements with the Vancouver Island Gas Joint Venture were renewed. The new agreements extend until 2012, and the committed volume under the contracts were set at 12.5 TJ per day for 2006 to 2012, inclusive, down from 20 TJ per day in 2005.

TGVI has also entered into a firm transportation agreement with BC Hydro to serve BC Hydro's gas supply needs to a gas-fired cogeneration plant at Elk Falls, B.C. The agreement, for 45 TJ per day, expires on December 31, 2007. BC Hydro has an option to extend the agreement for one year. BC Hydro has indicated that it is considering changing the Elk Falls facility from a baseload facility to a dispatchable facility. Accordingly, there is no certainty that the firm transportation agreement with BC Hydro will be extended beyond 2007.

On February 16, 2005, the BCUC approved TGVI's proposed liquefied natural gas (LNG) storage facility, subject to several conditions including the execution of a long-term Transportation Service Agreement (TSA) with BC Hydro backed by the capacity demand requirements of the Duke Point Power project. On June 17, 2005, BC Hydro announced its intention to abandon the Duke Point Power project on Vancouver Island as a result of a continuing appeal process. As a result, the expected construction timeline for TGVI's proposed storage facility has been delayed and, pending re-evaluation, will require BCUC approval prior to proceeding.

Petroleum Transportation

	Years ended December 31	
	2005	2004
	(in millions of dollars)	
Petroleum transportation revenues	**$227.8**	$225.5
Petroleum transportation net earnings	**64.5**	70.9

Revenues from petroleum transportation increased by $2.3 million in 2005 compared to 2004 as a result of higher revenues on the Corridor system, which offset lower throughput on the Trans Mountain system in the first quarter of 2005 as discussed below. Corridor revenues were higher in 2005 as a result of the refund in 2004 of deferral account balances to the Corridor shippers.

Earnings from petroleum transportation declined from $70.9 million in 2004 to $64.5 million in 2005 mainly as a result of lower throughput on the Trans Mountain system and a lower allowed return on equity on the Corridor system, offset in part by higher earnings from the Express System as a result of the completion of the Express expansion project. Earnings in 2005 were also impacted by a $7.3 million aftertax charge to earnings associated with the redemption of the Trans Mountain Series C Debentures.

TRANSPORTATION VOLUMES

	Years ended December 31	
	2005	2004
	(barrels per day)	
Trans Mountain Canadian mainline	**220,900**	236,100
Trans Mountain U.S. mainline	**74,600**	91,700
Express System	**213,000**	175,900

Actual throughput on the Corridor Pipeline does not impact earnings as all of Corridor's capacity is contracted through ship-or-pay arrangements.

Throughput in the first quarter of 2005 on the Trans Mountain system was impacted by the decline in production from the Alberta oilsands resulting from temporary production outages, as well as turnarounds at refineries connected to the Trans Mountain pipeline. These issues affected throughput on both the Canadian and U.S. mainlines. Volumes returned to more normal levels for the remainder of 2005.

Throughput on the Express System increased in 2005 as a result of the completion of the Express expansion project in April 2005.

TRANS MOUNTAIN

Earnings from Trans Mountain were $25.4 million in 2005, down from $39.4 million in 2004 mainly as a result of the costs of the Trans Mountain Series C Debenture redemption and the reduction in throughput on the Trans Mountain system in the first quarter of 2005.

Regulation

The National Energy Board (NEB) regulates the Canadian portion of Trans Mountain's crude oil and refined products pipeline system. The NEB authorizes pipeline construction and establishes tolls and conditions of service.

In November 2000, Trans Mountain and shipper representatives reached a negotiated agreement to determine Trans Mountain's tolls for the period 2001-2005. This Incentive Toll Settlement (ITS) was approved by the NEB on March 22, 2001 to take effect as of January 1, 2001.

The 2001-2005 ITS establishes base tolls, within a band of approximately 179,000 to 201,000 bpd, on Trans Mountain's Canadian mainline for the term of the settlement. Base tolls are set using a throughput level of approximately 189,000 bpd. Any revenue shortfalls arising from annual throughput levels below 179,000 bpd are recovered from the shippers. Incremental revenues arising from annual throughput above 201,000 bpd are shared equally between Trans Mountain and the shippers. The base tolls do not escalate with inflation unless Canadian inflation rates increase above 3.5%. Trans Mountain keeps all of the benefits achieved through productivity initiatives and operating efficiencies.

In January 2006, Kinder Morgan Canada entered into a memorandum of understanding with the Canadian Association of Petroleum Producers (CAPP) for a new Incentive Toll Settlement (the 2006-2010 ITS). The 2006-2010 ITS will determine the tolls to be charged on the Trans Mountain system over the five-year term of the agreement, to take effect as of January 1, 2006. The agreement will also govern the financial arrangements for the Pump Station Expansion and Anchor Loop projects. The 2006-2010 ITS is subject to National Energy Board (NEB) approval, and Kinder Morgan Canada and CAPP will work toward a final agreement by the end of June 2006. In addition to tolling and expansion parameters, the formal agreement will allow for new pipeline rules and regulations, capacity allocation procedures for the Westridge Marine Terminal and enhanced service standards.

The toll charged for the U.S. portion of Trans Mountain's pipeline in Washington State falls under the jurisdiction of the Federal Energy Regulatory Commission (FERC). Regulation by FERC is on a complaint basis. There were no complaints in 2005.

Trans Mountain Pump Station Expansion Project

On Nov. 10, 2005, Kinder Morgan Canada received approval from the National Energy Board (NEB) to increase the capacity of the Trans Mountain pipeline system from 225,000 bpd to 260,000 bpd. The $230 million expansion is designed to add 35,000 bpd of heavy crude oil capacity by building new and upgrading existing pump stations along the pipeline system between Edmonton, Alberta, and Burnaby, British Columbia. Construction began in early 2006 and the expansion will be in service in early 2007.

Trans Mountain Anchor Loop Project

Kinder Morgan Canada filed a comprehensive environmental report with the Canadian Environmental Assessment Agency on Nov. 15, 2005, and filed a complete NEB application for the Anchor Loop project on February 17, 2006. The $400 million project involves twinning a 158-kilometre section of the existing Trans Mountain pipeline system between Hinton, Alberta, and Jackman, British Columbia, and the addition of three new pump stations. With construction of the Anchor Loop, the Trans Mountain system's capacity will increase from 260,000 bpd to 300,000 bpd by the end of 2008.

Based on management's expectations for petroleum transportation demand to the West Coast of British Columbia and shipper feedback, Kinder Morgan Canada has decided not to seek long-term contracts with shippers for the Pump

Station Expansion Project or the Anchor Loop Project. As a result, there is no certainty that shipments on the Trans Mountain system will be sufficient to adequately recover the entire capital costs of the Pump Station and Anchor Loop expansions. However, the provisions of the 2006-2010 ITS will mitigate Trans Mountain's financial exposure to throughput shortfalls during that timeframe.

Beyond the Anchor Loop project, Kinder Morgan Canada is actively pursuing TMX 2, an approximately $1 billion project that would loop the Trans Mountain pipeline between Valemont and Kamloops and back to Edmonton, increasing throughput by 100,000 bpd, and TMX 3, a $900 million project that would loop the Trans Mountain pipeline between Kamloops and the Lower Mainland, increasing throughput by 300,000 bpd. Kinder Morgan Canada plans to conduct open seasons for both projects in 2006. Further into the future, Kinder Morgan Canada is considering building a new 400,000 bpd pipeline across northern British Columbia to a new deep-water port facility in Kitimat, British Columbia at a projected cost of $2.0 billion.

Kinder Morgan Canada is no longer pursuing the previously announced Spirit Pipeline due to the termination of arrangements with its project partner.

CORRIDOR

Earnings from the Corridor system were $13.6 million in 2005, down from $15.6 million in 2004 as a result of a lower allowed return on equity caused by lower long Canada bond yields in 2005 compared to 2004. The Firm Service Agreement (FSA) between Corridor and its shippers sets pipeline tolls based on conventional cost of service mechanisms. The FSA is a 25-year agreement, with return on equity linked to prevailing long Canada bond yields. Shell Canada Limited, Chevron Canada Limited and Western Oil Sands L.P. have entered into a long-term ship-or-pay contract with Corridor for 60%, 20% and 20%, respectively, of the available capacity on the Corridor Pipeline.

Corridor Pipeline Expansion

Kinder Morgan Canada has initiated engineering, environmental and consultation activities on its proposed Corridor pipeline expansion project. The $1.0 billion expansion includes building a new 42-inch diluent/bitumen (dilbit) pipeline, a new 20 inch products pipeline, tankage and upgrading existing pump stations along the existing pipeline system from the Muskeg River Mine north of Fort McMurray to the Edmonton region. The Corridor pipeline expansion will add an initial 200,000 bpd of dilbit capacity to accommodate the new bitumen production from the Muskeg River Mine. The current dilbit capacity is approximately 258,000 bpd. It is expected to climb to 278,000 by April 2006 by upgrading existing pump station facilities. By 2009, the dilbit capacity of the Corridor system is expected to be approximately 500,000 bpd. An application for the Corridor Pipeline Expansion Project was filed with the Alberta Energy and Utilities Board on December 22, 2005. Pending regulatory and definitive shipper approval, construction will begin in late 2006.

EXPRESS SYSTEM

Earnings from the Express System were $25.5 million in 2005, up $9.6 million from 2004, as a result of the completion of the Express System capacity expansion in April 2005, and the additional throughput that the Express System was able to transport due to the expansion, and due to the realization of additional tax benefits.

In late 2003 and 2004, Terasen conducted open seasons to obtain long-term commitments for a portion of the Express System's uncommitted capacity and for expansion capacity. Express has 84% of its 280,000 bpd post-expansion total capacity contracted. These contracts expire in 2007, 2012, 2014 and 2015 in amounts of 1%, 40%, 11% and 32% of total capacity, respectively. These contracts provide for committed tolls for transportation on the Express System, which can be increased each year by up to 2%. The remaining capacity is made available to shippers as uncommitted capacity.

Other Activities

	Years ended December 31	
	2005	2004
	(in millions of dollars)	
Other activities revenues	**$46.7**	$78.5
Other activities net (loss)	**(49.2)**	(20.3)

Revenues from other activities declined from $78.5 million in 2004 to $46.7 million in 2005 as a result of the change in accounting treatment for Clean Energy from proportionate consolidation to equity accounting.

The loss from other activities increased from $20.3 million in 2004 to $49.2 million in 2005 primarily as a result of $34.4 million of costs incurred in connection with the acquisition of the Company by KMI.

Discontinued Operations

The water and utility services operations incurred a loss of $4.9 million in 2005, compared to earnings of $3.3 million in 2004. The decline in earnings was due to the expiry of tax loss carryforwards associated with the KMI acquisition and the recognition of a currency translation loss resulting from the pending sale of the business, somewhat offset by strong operating performance in the business.

Summary of Quarterly Results

	For the three months ended				
	Mar-31	Jun-30	Sep-30	Dec-31	Total
			($ millions)		
2005					
Revenues (restated)[1]	$627.5	$354.3	$282.6	$688.1	$1,952.5
Net income before discontinued operations	66.9	27.1	0.9	11.2	106.1
Net income	66.3	29.5	4.0	1.4	101.2
2004					
Revenues (restated)[1]	625.1	321.6	275.6	575.8	1,798.1
Net income before discontinued operations	68.6	16.1	7.6	54.2	146.5
Net income	67.9	17.9	10.1	53.9	149.8

1. Revenues for 2004 and 2005 have been restated to reflect the reclassification of the water and utility services business as a discontinued operation, and to reclassify certain revenues from Clean Energy to equity accounting.

Because of natural gas consumption patterns, the natural gas distribution operations of Terasen Gas normally generate higher net earnings in the first and fourth quarters, which are offset by net losses in the second and third quarters. The Company's water and utility services business, which has been reclassified as a discontinued operation, typically experiences stronger second and third quarter results, offset by weaker first and fourth quarter results, based on the level of construction and general economic activity. Earnings from Terasen's petroleum pipeline operations are not subject to material fluctuations due to seasonality. As a result, interim earnings statements are not indicative of earnings on an annual basis.

Revenues in 2005 were generally higher than in 2004 on a quarterly and annual basis as a result of higher natural gas commodity prices in 2005.

March 2005/2004 — Earnings declined by $1.6 million due to temporary lower petroleum transportation throughput resulting from the decline in production from the Alberta oilsands and maintenance turnarounds at refineries connected to the Trans Mountain pipeline. Strong operating results from the other business units were able to offset the majority of the earnings decline from petroleum transportation.

June 2005/2004 — Earnings increased by $11.6 million, driven by growth in earnings from all areas of operations. Customer growth and operating efficiencies in the quarter were the primary factors in the $2.6 million growth in earnings from natural gas distribution. Higher throughput on the Trans Mountain mainline and the implementation of the Express System expansion resulted in a $4.7 million increase in contribution from petroleum transportation. Growth in earnings from Waterworks and Clean Energy were the key drivers of the improvement in year-over-year earnings contribution from water and utility services and other activities.

September 2005/2004 — Earnings declined by $6.1 million over the prior year third quarter, but include the hedging activities and disposition costs associated with Clean Energy and transaction costs associated with the KMI acquisition. After excluding these items, earnings increased by $4.2 million through a combination of growth in earnings from all three business units, which more than offset increased corporate expenses for the quarter.

December 2005/2004 — Earnings declined by $52.5 million mainly as a result of costs incurred in connection with the acquisition of the Company by KMI of $38.9 million, as well as a charge to earnings associated with the redemption of the Trans Mountain Series C Debentures of $7.3 million.

Liquidity and Capital Resources

Consolidated Cash Flow

	Years ended December 31	
	2005	2004
	(in millions of dollars)	
Cash flow provided by (used for):		
Operating activities	**$195.4**	$335.4
Investing activities	**(212.5)**	(160.2)
Financing activities	**76.5**	(156.7)
Net increase in cash	**$ 59.4**	$ 18.5

CASH FLOW FROM OPERATING ACTIVITIES

Cash flow from operating activities declined from $335.4 million in 2004 to $195.4 million in 2005 due to a number of factors. Net earnings were lower in 2005 as a result of the items disclosed above in the ''Certain Items'' table. The net recovery of rate stabilization accounts in 2005 was $10.1 million compared with $31.0 million in 2004, mainly due to higher rate stabilization account receivable balances at the beginning of 2004. In addition, changes in non-cash working capital were a use of $68.3 million in 2005 compared to a source of $14.7 million in 2004, mainly as a result of the impact of higher gas prices on the value of natural gas inventory and accounts receivable.

INVESTING ACTIVITIES

Proceeds from the sale of natural gas distribution assets in municipal leasing transactions largely offset the acquisition of water and utility services businesses in 2004, whereas expenditures on the water and utility services business in 2005 were largely offset by proceeds from the disposition of the Company's interest in Clean Energy.

Capital expenditures totaled $214.7 million in 2005 compared with $154.4 million in 2004. The increase in capital expenditures was primarily attributable to the acquisition of the Coastal Facilities buildings. Prior to January 2005, the Coastal Facilities synthetic lease agreement had been accounted for as an off-balance sheet item. In 2004, Terasen Gas applied to the BCUC for and received approval to unwind the synthetic lease and include the Coastal Facilities assets in rate base. On January 4, 2005, Terasen Gas paid approximately $49.4 million to BCG Coastal Facilities Trust to unwind the synthetic lease. The Coastal Facilities assets have been included in the Terasen Gas rate base commencing January 2005.

FINANCING ACTIVITIES

In February 2005, Terasen Gas issued $150 million of 30-year medium term note debentures at an interest rate of 5.90%. In October 2005, Terasen Gas issued $150 million of two-year medium term note debentures at a floating rate of interest. In the second quarter of 2004, Terasen Gas issued $150 million of medium term note debentures at an interest rate of 6.50%. Funds generated from the issuance of medium term note debentures were used for general corporate purposes of Terasen Gas and to refinance maturing medium term debentures.

In February 2005, Corridor issued $150 million each of 5-year and 10-year unsecured debentures at rates of 4.24% and 5.033%, respectively. Proceeds were used to repay commercial paper issued by Corridor.

In September 2005, Trans Mountain announced that it had exercised its right to redeem the $35 million principal amount 11.50% Series C Debentures, due June 20, 2010. The redemption took place on November 1, 2005. The total redemption price for the Debentures was $1,353.7615 per $1,000 principal amount, which includes accrued and unpaid interest to the redemption date. The redemption price was determined based on the Canada Yield Price, as defined in the Trust Indenture governing the Debentures.

As at December 31, 2005, the Company and its subsidiaries had lines of credit in place totaling $1,175 million to finance cash requirements. These lines enable the respective companies to borrow directly from their bankers, issue bankers' acceptances and support commercial paper issuance. Bank lines of $375 million were unutilized at the end of 2005. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the

Canadian market at rates generally below bank prime. Terasen does not have, nor does it expect to have, any defaults or arrears.

On January 13, 2006, Terasen Gas (Vancouver Island) Inc. entered into a five-year unsecured, committed, revolving credit facility of $350 million with a syndicate of banks, of which $296 million was drawn against the facility on January 17, 2006. A portion of the facility was used to refinance TGVI's existing term facility of $209.5 million. The facility will also be utilized to finance working capital requirements and general corporate purposes.

Concurrently with executing the above noted facility, TGVI entered into a $20 million, seven-year unsecured, committed, non-revolving credit facility with one bank. This facility will be utilized for purposes of refinancing any annual prepayments TGVI may be required to make on non-interest bearing government contributions. The terms and conditions are primarily the same as the aforementioned TGVI facility except this facility ranks junior to repayment of TGVI's Class B subordinated debt which is held by the Company.

Dividends on common shares totaled $95.1 million in 2005, compared to $86.4 million in 2004. The increase reflects an increase in the dividend rate paid on common shares in 2005.

Financial Position

The following table outlines the significant changes in the consolidated balance sheets as at December 31, 2005 compared to December 31, 2004, other than changes arising from the reclassification of the water and utility services business as a discontinued operation.

Balance Sheet Item	Increase (Decrease) ($ millions)	Explanation
Cash and short-term investments	$ 59.4	Increased as a result of significant cash flow in late 2005 that was used to repay short-term notes subsequent to year end.
Accounts receivable	119.5	Increased mainly as a result of the impact of higher gas prices on accounts receivable for Terasen Gas and TGVI, partially offset by the reclassification of accounts receivable in the water and utilities services segment into assets held for resale.
Goodwill	(51.6)	Declined as a result of the disposition of Clean Energy and the reclassification of water and utility services as long lived assets held for resale.
Short-term notes	433.0	The refinancing of the Corridor bank credit facility resulted in the reclassification of Corridor's remaining commercial paper outstanding from long-term debt to short-term notes. In addition, short-term note balances at the end of 2004 were relatively low as a result of long-term debt issuance in 2004 that pre-funded long-term debt maturities in 2005.
Accounts payable and accrued liabilities	68.1	Increased mainly as a result of the impact of higher gas prices on accounts payable for Terasen Gas and TGVI, offset by the reclassification of accounts payable in the water and utilities services segment into liabilities held for resale.
Long-term debt (including current portion)	(297.2)	The refinancing of the Corridor bank credit facility resulted in the reclassification of Corridor's remaining commercial paper outstanding from long-term debt to short-term notes. In addition, long-term debt maturities in 2005 were partially pre-funded by long-term debt issuance in 2004.

Working Capital

Terasen's working capital requirements fluctuate seasonally based on natural gas consumption. Given the regulated nature of its business, Terasen is able to maintain negative working capital balances. Terasen maintains adequate committed credit facilities to meet its working capital requirements. On an annual basis, Terasen generates sufficient cash flow to meet its working capital requirements.

Dividend Restrictions

As part of its approval of the acquisition of Terasen by KMI, the BCUC imposed a number of conditions intended to ring-fence Terasen Gas and TGVI from Terasen. These restrictions included a prohibition on the payment of dividends unless Terasen Gas or TGVI has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. As a result of this and the Decision issued by the BCUC on March 2, 2006 Terasen Gas and TGVI must maintain a percentage of common equity to total capital that is at least as much as that determined by the BCUC from time to time for ratemaking purposes. Dividend payments will not be allowed by the regulator if the requisite equity is not in place.

Dividend policies are set to ensure that Terasen Gas and TGVI maintain at least as much common equity as that deemed by the BCUC for rate-making purposes.

Corridor's credit agreement restricts its ability to issue dividends subject to certain debt-to-total capital requirements. Cash distributions from Express are subject to limitations in the Express financing agreements and decisions made by the Express Board of Directors, which Terasen does not control.

In 2005, none of these restrictions constrained the distribution of subsidiary earnings not otherwise needed for reinvestment.

Credit Ratings

Securities issued by Terasen, Terasen Gas and Corridor are rated by DBRS Inc. (DBRS) and Moody's Investors Service Inc. (Moody's). The ratings assigned to securities issued by the Terasen group of companies are reviewed by these agencies on an ongoing basis.

The table below summarizes the ratings assigned to the Company's various securities at December 31, 2005.

CREDIT RATINGS	DBRS	MOODY'S
Terasen Inc.		
Commercial paper	R-2 (High)	
Unsecured long-term debt	BBB (High)	Baa2
Capital securities	BBBy	Baa3
Terasen Gas Inc.		
Commercial paper	R-1 (Low)	
Secured long-term debt	A	A2
Unsecured long-term debt	A	A3
Terasen Pipelines (Corridor) Inc.		
Commercial paper	R-1 (Low)	
Unsecured long-term debt	A	A2

Trans Mountain's ratings were withdrawn by DBRS in late 2005 following the redemption of Trans Mountain's Series C Debentures. Trans Mountain no longer has indebtedness to third parties.

A number of ratings actions were taken on Terasen in December 2005 following the acquisition of Terasen by KMI to make the ratings consistent with those of KMI. Moody's downgraded the ratings on Terasen's unsecured long-term debt and capital securities by two gradations each (from A3 to Baa2 in the case of unsecured long-term debt). DBRS downgraded Terasen's ratings on unsecured long-term debt and capital securities by one gradation each (from A (Low) to BBB (High) in the case of unsecured long-term debt). DBRS also downgraded Terasen's commercial paper rating from R-1 (Low) to R-2 (High). As a result, it is no longer economic for Terasen to issue commercial paper in the Canadian market, and Terasen is issuing Bankers' Acceptances under its committed credit facilities to fund its short-term borrowing requirements.

Also in December 2005, Moody's downgraded Terasen Gas' long-term debt ratings by one gradation. However, Moody's noted that this downgrade was unrelated to the KMI acquisition, and was a result of Terasen Gas' weak financial profile compared to its peers.

After reassessing its relationship with Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies (Canada) Corporation (S&P), Terasen decided early in 2004 to discontinue the engagement of S&P to provide credit ratings on the debt of Terasen and Terasen Gas. Terasen believes the credit ratings issued by Moody's and DBRS will be sufficient to service the requirements of creditors and maintain the Company's access to capital. S&P continues to provide an unsolicited rating on Terasen's outstanding debt based on publicly available information. As of December 31, 2005, Terasen's unsecured long-term debt was rated BBB– by S&P.

There is a provision in Terasen's $450 million credit facilities that a downgrade of Terasen's unsecured long-term debt rating below BBB (low) or Baa3 by DBRS or Moody's, respectively, would shorten the remaining term of Terasen's credit facility to ten months. In addition, a downgrade of Terasen Gas below investment grade by any of the major credit rating agencies could trigger margin calls and other cash requirements under Terasen Gas' gas purchase and commodity derivative contracts.

Projected Capital Expenditures

Terasen has estimated total 2006 consolidated capital expenditures of $501 million. Major capital expenditures in 2006 include construction on the Trans Mountain Pump Station Expansion project ($168 million), initial expenditures on the Corridor Pipeline Expansion ($95 million) and upgrades to the Trans Mountain U.S. mainline in Washington State to support future expansion ($31 million).

The Company expects to finance capital expenditures in 2006 with a combination of proceeds from the refinancing of TGVI's credit facility and shareholder advances, short-term borrowings and internally generated funds. The Company does not expect to pay common dividends to its shareholder in 2006, instead retaining its earnings for reinvestment in growth opportunities.

Off-Balance Sheet Arrangements

In 2000, Terasen Gas entered into a leasing arrangement with a syndicate of Canadian banks and the BCG Coastal Facilities Trust, a special-purpose entity, to finance new building facilities in the Greater Vancouver area. The Coastal Facilities synthetic lease agreement had been accounted for as an off-balance sheet item. As at December 31, 2004, the value of the Coastal Facilities leasing agreement was approximately $49.4 million. Lease payments of approximately $4.5 million were made by Terasen Gas in 2004.

In 2004, Terasen Gas applied to the BCUC for and received approval to unwind the synthetic lease and include the Coastal Facilities assets in rate base. On January 4, 2005, Terasen Gas paid approximately $49.4 million to BCG Coastal Facilities Trust to unwind the synthetic lease. The Coastal Facilities assets have been included in the Terasen Gas rate base commencing January 2005.

Other than the Coastal Facilities lease, which has been refinanced, there are no other material off-balance sheet agreements.

Transactions with Related Parties

The Company has not had any significant transactions with related parties outside of the consolidated group in 2005.

Changes in Accounting Policies

Liabilities and Equity

In accordance with recent changes to the CICA Handbook Section 3861 ''Financial Instruments — Disclosures and Presentation'', the Company's $125 million 8% Capital Securities have been reclassified from shareholders' equity to liabilities because the Capital Securities can be settled by issuing equity at a variable price dependent upon the market value of the Company's common shares at the settlement date. As a result of the change, distributions associated with the Capital Securities are now recorded as financing costs and the related income-tax benefits are recorded within income tax expense. Previously, the distributions were recorded on an after-tax basis as a deduction from net earnings to determine earnings applicable to common shares. There is no impact to earnings applicable to common shares or earnings per share. The changes have been applied retroactively and have increased long-term debt and decreased shareholders' equity, both by $125.0 million, compared to the amounts previously reported as at December 31, 2004. The restatement has also increased financing costs by $10.0 million, decreased income tax expense by $3.4 million and capital securities distributions by $6.6 million compared to the amounts previously reported for the year ended December 31, 2004.

Variable Interest Entities
In January 2005, the Company adopted the CICA Handbook Accounting Guideline 15 ''Consolidation of Variable Interest Entities''. The Company has performed a review of the entities with whom it conducts business and determined that under the definitions in the Guideline the Company's investment in Express US Holdings LP, part of the Express System (the ''Express System''), is deemed to be a variable interest entity. As the Company has not been identified as the primary beneficiary of Express US Holdings LP, the Company continues to account for its investment in the Express System on an equity basis. The Company's future exposure to loss regarding its investment is represented by the carrying value of the investment.

Rate Regulated Entities
The Canadian Institute of Chartered Accountants have undertaken a project to review and change how rate regulated enterprises recognize and measure regulated assets and liabilities. The results of this project could introduce significant volatility into the earnings of such businesses, which may include the elimination of regulatory deferral accounts. The project could also require rate regulated enterprises to include future income taxes payable on their balance sheets. There is very real risk that this could negatively affect debt covenant compliance and impact utilities' ability to attract financing and equity capital. The industry has actively intervened in this process over the past two years, and an exposure draft on this matter is anticipated in late 2006.

Disclosure Controls and Procedures
The President and the Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Multilateral Instrument 52-109) and concluded that the company's disclosure controls and procedures were effective as of December 31, 2005.

Financial Instruments
Fair Value Estimates
The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2005, or by using available quoted market prices, is estimated at $2,673.4 million. The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

Derivative Instruments
The Company uses derivative instruments to hedge its exposures to fluctuations in natural gas prices and interest rates. As approved by the regulator, derivatives are used to manage natural gas price risk in the natural gas distribution operations. The majority of the natural gas supply contracts have floating, rather than fixed prices. The Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in a deferral account (MCRA and CCRA), and subject to regulatory approval, are passed through in future rates to customers.

The Company's short-term borrowings and variable rate long-term debt are exposed to interest rate risk. The Company manages interest rate risk through the use of interest rate derivatives. Foreign currency risk in natural gas distribution operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through regulatory deferral accounts.

The Company's earnings from the U.S. portion of Trans Mountain's crude oil pipeline system and the Company's investment in the Express System are subject to foreign currency risk. The Company's earnings are also subject to translation risk associated with certain Express System assets and liabilities.

			December 31, 2005		December 31, 2004	
Asset (Liability)	**Number of swaps and options**	**Term to maturity (years)**	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
			(in millions)			
Interest Rate Swaps[1]						
Terasen Inc.	3	1 - 9	$ —	$ 3.6	$ —	$5.4
TGI	3	2	—	(1.6)	—	—
TGVI	4	1 - 4	—	(0.6)	—	(3.2)
Corridor	2	5 - 10	—	0.3	—	—
Natural Gas Commodity Swaps and Options						
Terasen Gas and TGVI[2]	161	Up to 3	21.2	105.6	—	(8.3)
Clean Energy[3]	—	—	—	—	6.5	6.5
Foreign Currency Swaps						
Terasen Inc.[4]	—	—	—	—	(0.6)	(0.6)

1 The interest rate derivatives entered into by Terasen Inc. resulted in lower interest expense of $4.8 million in 2005, compared with a $3.6 million interest expense reduction in 2004. The derivatives entered into by TGI and TGVI relate to regulated operations and any resulting gains or losses are recorded in deferral accounts, subject to regulatory approval, and passed through to customers in future rates. The gains and losses associated with derivatives entered into by Corridor are similarly passed through to shippers in future rates.

2 The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates. Included in the carrying value of the natural gas derivatives is $22.2 million of unrealized fair value gains associated with derivative instruments which were deemed to be ineffective at December 31, 2005, and $1.0 million of derivative instruments which did not qualify for hedge accounting that are in a liability position. The gains and losses associated with natural gas derivatives are recorded in deferral accounts, subject to regulatory approval, and passed through to customers in future rates.

3 Clean Energy entered into natural gas commodity derivatives to manage its exposure to the cost of natural gas. These transactions resulted in a $10.9 million contribution to earnings in 2005, compared with a $3.3 million contribution in 2004. The carrying and fair value of Clean Energy's natural gas commodity swaps at December 31, 2004 reflected Terasen's 45.0% ownership interest at that time. Terasen disposed of its interest in Clean Energy on October 31, 2005.

4 The change in fair value of the derivatives of $1.6 million in 2005 and $0.7 million in 2004 has been included in the earnings contribution from the Express System for the respective periods.

Outstanding Share Data

December 31, 2005

Common shares issued and outstanding	115,643,162
Less: Common shares held by Terasen Pipelines (Trans Mountain) Inc.	9,184,188
	106,458,974
8.0% capital securities issued and outstanding	$125,000,000

Terasen is an indirect wholly-owned subsidiary of Kinder Morgan, Inc. At December 31, 2005 all of the common shares of the Company are owned by Kinder Morgan, Inc.

The 8.0% capital securities are exchangeable on or after April 19, 2010 for common shares of the Company at 90% of the market price, subject to the right of the Company to redeem the securities for cash. A maximum of 125,000,000 common shares could be issued if this right was exercised.

Forward Looking Statement

When used in this report, the words ''anticipate'', ''expect'', ''project'', ''believe'', ''estimate'', ''forecast'' and similar expressions are intended to identify forward looking statements, which include statements relating to pending and proposed projects or possible acquisitions. Such statements are subject to certain risks, uncertainties and assumptions pertaining to operating performance, regulatory parameters, economic conditions and, in the case of pending and proposed projects, risks relating to design and construction, regulatory processes, obtaining financing and performance of other parties, including partners, contractors and suppliers and in the case of possible acquisitions, obtaining financing, acquiring assets or companies at an appropriate price and the ability to effect synergies in a timely and cost-effective manner.

Additional Information

Additional information relating to Terasen Inc. is available on SEDAR at www.sedar.com.

Terasen Inc.

Interim Management's Discussion and Analysis
For the three and nine Months Ended September 30, 2006
Dated November 27, 2006

The following discussion of the financial condition and the results of operations of Terasen Inc. (Terasen or the Company) should be read in conjunction with the Company's December 31, 2005 annual audited consolidated financial statements and related notes together with Management's Discussion and Analysis and the unaudited interim consolidated financial statements and related notes for the periods ended September 30, 2006.

In this MD&A, we, us, our, the Company and Terasen mean Terasen Inc., its subsidiaries, joint ventures and investments in significantly influenced companies. Terasen Gas refers to Terasen Gas Inc., TGVI refers to Terasen Gas (Vancouver Island) Inc., Trans Mountain refers to Terasen Pipelines (Trans Mountain) Inc., Corridor refers to Terasen Pipelines (Corridor) Inc., Kinder Morgan Canada refers to Kinder Morgan Canada Inc., Express refers to the Express and Platte Pipeline Systems; and Water and Utility Services refers to Terasen Waterworks (Supply) Inc., Terasen Utility Services Inc. and Terasen's 50% interest in Fairbanks Sewer and Water Inc. KMI or the parent refers to Kinder Morgan, Inc.

The financial data included in the discussion provided in this report has been prepared in accordance with Canadian generally accepted accounting principles, and all dollar amounts are in Canadian dollars.

THIRD QUARTER 2006 FINANCIAL RESULTS

Result of Operations

	Three months ended September 30		Nine months ended September 30	
NET EARNINGS	**2006**	2005	**2006**	2005
	In millions of dollars			
Natural gas distribution	**$(6.8)**	$(3.6)	**$48.3**	$59.8
Petroleum transportation	**17.4**	17.2	**51.6**	50.8
Discontinued operations[1]	**(4.1)**	3.1	**(17.0)**	4.9
Other activities	**(4.0)**	(12.7)	**(17.7)**	(15.7)
Net earnings	**$ 2.5**	$ 4.0	**$65.2**	$99.8

1 In January 2006, Terasen entered into a Purchase and Sale Agreement to dispose of its interest in its water and utility services operations for proceeds of approximately $132 million. The disposition was completed on May 19, 2006 with the proceeds from the sale being used to reduce debt. The disposition gave rise to a $17.0 million loss which has been fully recorded.

Terasen reported earnings of $2.5 million for the three months ended September 30, 2006 compared with earnings of $4.0 million in the corresponding quarter of 2005. For the nine months ended September 30, 2006, earnings were $65.2 million compared to $99.8 million in the nine months of 2005. The decrease in earnings for the nine months is mainly due to a provision of $14.5 million made for retroactive tax amending legislation that was introduced in a provincial legislature, a loss of $17.0 million recorded on the sale of water and utility services operations and the $2.2 million loss of earnings from Clean Energy operations which was disposed on October 31, 2005.

Results by Business Segment

Natural Gas Distribution

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
	In millions of dollars			
Revenues	**$217.0**	$213.7	**$1,204.6**	$1,065.8
Net earnings	**$ (6.8)**	$ (3.6)	**$ 48.3**	$ 59.8

For the three and nine months ending September 30, 2006, revenues from natural gas distribution increased by $3.3 million and $138.8 million, respectively, compared to the corresponding periods in 2005. Cost of natural gas, on a year-over-year basis, decreased $1.0 million in the third quarter and increased $130.2 million for the nine months ended September 30, 2006. Higher revenues and cost of natural gas reflected mainly the higher commodity cost of gas charged to customers due to higher market prices and some customer growth in the quarter. Changes in both consumption levels and the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts.

As noted in the Company's annual 2005 Management's Discussion and Analysis, the allowed Return on Equity (''ROE'') for 2006 for Terasen Gas has been set at 8.80% (9.03% in 2005) and at 9.50% for TGVI (9.53% in 2005), In addition, the deemed equity components for Terasen Gas and TGVI, with the approval of the British Columbia Utilities Commission (''BCUC'') were increased to 35% and 40% respectively in 2006 compared to 33% and 35% in 2005.

For the three months ended September 30, 2006, Terasen Gas and TGVI net customer additions were 1,102 and 1,150 respectively, bringing the total number of utility customers to 896,488 at September 30, 2006. Although the net increase of 6,126 customers for the first three quarters of 2006 is lower than the 8,446 net new customers reported in the same period of 2005, favorable economic conditions and housing activity in British Columbia continue to drive customer growth in the region.

Although the above items result in higher earnings for both Terasen Gas and TGVI, overall loss for the gas distribution segment have increased by $3.2 million in the third quarter of 2006, mainly due to higher non-recurring bad debt expenses related to the unbilled basic charge revenues in the current quarter compared to the same quarter in the prior year. Earnings for the first nine months of 2006 were $48.3 million compared to $59.8 million in 2005. The decline in the earnings in 2006 compared to 2005 is mainly due to a tax provision made in the second quarter related to the retroactive tax amending legislation in the Province of Quebec. The remaining difference is a result of TGVI's operations and maintenance (''O&M'') expenses which were rebased as part of its 2006-2007 rate settlement and reduced the contribution of incentive earnings in 2006. In addition, Terasen Gas has changed the timing of its recognition of earnings sharing obligation related to its forecast O&M and capital expenditures incentives to coincide with the timing of revenues received. Previously, these obligations were recognized on a straight line basis. This change affects the timing of revenues and net earnings for each quarter but is not a material amount.

Petroleum Transportation

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
	In millions of dollars			
Revenues	**$60.4**	$57.3	**$168.2**	$163.0
Net earnings	**$17.4**	$17.2	**$ 51.6**	$ 50.8

Transportation volumes	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
	(barrels per day)			
Trans Mountain Canadian mainline	**236,700**	229,100	**230,700**	213,900
Trans Mountain U.S. mainline	**103,000**	84,900	**97,800**	68,200
Express System	**249,200**	224,600	**230,700**	205,200

Actual throughput on the Corridor Pipeline does not impact earnings as all of Corridor's capacity is contracted through ship-or-pay arrangements.

Revenues from petroleum transportation were $60.4 million in the third quarter of 2006, up $3.1 million from the same quarter of 2005 mainly due to higher throughput in the third quarter of 2006 offset partially by lower tolls. For the first three quarters of 2006, revenues were $168.2 million as compared to $163.0 million in the same period of 2005. Year-to-date revenues were slightly higher than the previous year's nine months as the first quarter of 2005 was negatively impacted by temporary production outages and turnarounds at refineries, the impact of which is shown in the throughput figures.

Earnings from petroleum transportation were $17.4 million in the third quarter of 2006, up $0.2 million from the previous year's third quarter mainly due to higher revenues, as described above, offset by higher power and O&M expenses. Earnings increased to $51.6 million in the first nine months of 2006 compared to $50.8 million in the corresponding period of 2005, mainly due higher earnings in TransMountain due to the increase in revenues described above.

Other activities

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
	In millions of dollars			
Revenues	**$10.9**	$ 11.6	**$ 33.3**	$ 35.6
Net loss before discontinued operations	**$ (4.0)**	$ (12.7)	**$ (17.7)**	$ (15.7)

During the third quarter of 2006, revenues from other activities decreased by $0.7 million on a year-over-year basis as a result of a decrease in international operations revenues and a slight decrease in revenues from CustomerWorks LP due to some lower rates from contracts renegotiated in 2006. The loss from other activities decreased from $12.7 million in the third quarter of 2005 to $4.0 million in the third quarter of 2006. On a year to date basis, the loss increased to $17.7 million from a loss $15.7 million in the first nine months of 2005. The year over year change is primarily due to the inclusion of earnings and gains from hedging activities from Clean Energy in 2005, which Terasen disposed of on October 31, 2005, a tax provision of $3.5 million made in the second quarter of 2006 for retroactive tax amending legislation that was introduced in a provincial legislature and higher operating expenses due to management fees to KMI and $4.0 million of non-recurring charges in 2005 related to the acquisition of Terasen by Kinder Morgan.

Discontinued Operations

The water and utility operations incurred an incremental loss of $4.1 million in the third quarter of 2006 compared to $3.1 million of income in the corresponding period of 2005. The total loss recorded on the disposition of these operations amounted to $17.0 million.

QUARTERLY FINANCIAL INFORMATION

	2006			**2005**				**2004**
	Sept.	**June**	**Mar.**	**Dec.**	**Sept.**	**June**	**Mar.**	**Dec.**
Revenues	$288.3	$367.3	$750.5	$688.1	$282.6	$354.3	$627.5	$575.8
Net earnings before discontinued operations	$ 6.6	$ 6.1	$ 69.5	$ 11.2	$ 0.9	$ 27.1	$ 66.9	$ 54.2
Net (loss) earnings	$ 2.5	$ (1.6)	$ 64.3	$ 1.4	$ 4.0	$ 29.5	$ 66.3	$ 53.9

December 2005/2004 — Earnings declined by $52.5 million mainly as a result of costs incurred in connection with the acquisition of the Company by KMI of $38.9 million, as well as a charge to earnings associated with the redemption of the Trans Mountain Series C Debentures of $7.3 million.

March 2006/2005 — Earnings decreased by $2.0 million due to the expected loss of $5.0 million on the sale of the water and utility operation, offset by higher petroleum transportation throughput as the first quarter of 2005 was negatively impacted by the decline in production from the Alberta oilsands and maintenance turnarounds at refineries connected to the Trans Mountain pipeline. Higher throughput in the Express system also contributed to higher earnings as the expansion Project was completed in April 2005.

June 2006/2005 — Earnings decreased by $31.1 million due to a provision of $14.5 million made for retroactive tax amending legislation that was introduced in a provincial legislature, an incremental loss of $7.7 million recorded on the sale of water and utility services operations, the loss of earnings from Clean Energy operations which was disposed on October 2005, and higher operating expenses due to higher management fees.

September 2006/2005 — Earnings decreased by $1.5 million due to a loss on disposal of the water business offset by lower costs in 2006 due to 2005 one time transaction costs of $4.1 million on the sale of Clean Energy and $4.0 million of transaction costs associated with the Kinder Morgan acquisition incurred in 2005.

SEASONALITY

Because of natural gas consumption patterns, the natural gas distribution operations of Terasen Gas normally generate higher net earnings in the first and fourth quarters, which are offset by net losses in the second and third quarters. Earnings from Terasen's petroleum pipeline operations are not subject to material fluctuations due to seasonality. As a result, interim earnings statements are not indicative of earnings on an annual basis.

LIQUIDITY AND CAPITAL RESOURCES

Terasen expects to generate sufficient cash from operations to meet its working capital needs and to maintain its financial capacity and flexibility. The Company's liquidity and capacity to access capital markets to maintain operations and fund growth remain substantially unchanged since December 31, 2005.

CONSOLIDATED CASH FLOW

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
	In millions of dollars			
Cash flow provided by (used for):				
Operating activities	**$ (52.6)**	$ (17.0)	**$ 223.0**	$ 160.7
Investing activities	**$ (78.0)**	$ (53.1)	**$ (65.5)**	$ (182.9)
Financing activities	**$176.5**	$ 11.7	**$ (154.1)**	$ 35.4
Net increase in cash	**$ 45.9**	$ (58.4)	**$ 3.4**	$ 13.2

CASH FLOW FROM OPERATING ACTIVITIES

Cash from operations refers to cash generated before the impact of working capital and rate-stabilization deferral account changes. Cash from operations for the three months ended September 30, 2006 was $21.3 million, compared to $47.8 million in the corresponding period of 2005. Cash flow from for operating activities, which includes the impact of changes in working capital and deferral accounts, was $223.0 million in the first nine months of 2006 compared with $160.7 million in the corresponding period of 2005.

Between December 31, 2005 and September 30, 2006, accounts receivable, accounts payable and accrued liabilities declined while gas in storage inventory increased as a result of the typical seasonal increase in natural gas consumption during the period. These changes in working capital accounts and rate stabilization accounts generated increased cash flow from operating activities compared to 2005.

INVESTING ACTIVITIES

Capital expenditures totaled $84.1 million in the third quarter of 2006 compared to $43.4 million in the corresponding period in 2005. Year to date capital expenditures were $194.2 million in 2006 compared to $170.3 million in the first nine months of 2005. The increase in the third quarter is mainly due to expenditures incurred in the pipeline operations as construction of the first phase of the expansion of the Trans Mountain system West Coast pipeline expansion (''TMX'') is underway. The increase in capital expenditures on a year to date basis was primarily attributable to the TMX expansion which is currently underway. The decrease in the overall investing activities is due to the proceeds from the sale of the water and utility services business.

There have been no material changes to Terasen's planned capital expenditures from those reported in the Company's Annual 2005 Management's Discussion and Analysis.

FINANCING ACTIVITIES

On January 13, 2006, TGVI entered into a five-year unsecured, committed, revolving credit facility of $350 million with a syndicate of banks, of which $296 million was drawn against the facility on January 17, 2006. A portion of the facility was used to refinance TGVI's existing term facility of $209.5 million. The facility will also be utilized to finance working capital requirements and general corporate purposes.

Concurrently with executing the above noted facility, TGVI entered into a $20 million, seven-year unsecured, committed, non-revolving credit facility with one bank. This facility will be utilized for purposes of refinancing any annual prepayments TGVI may be required to make on non-interest bearing government contributions. The terms and conditions are primarily the same as those for the aforementioned TGVI facility except this facility ranks junior to repayment of TGVI's Class B subordinated debt which is held by the Company. Borrowings outstanding under this facility were $3.7 million as of September 30th, 2006.

On May 9, 2006, Terasen Inc. entered into a $450 million three-year revolving credit facility. This facility replaces three bi-lateral facilities aggregating $450 million and includes terms and conditions similar to the facilities it replaced.

On June 21, 2006, Terasen Gas Inc. entered into a $500 million three-year revolving credit facility, extendible annually for an additional 364 days at the option of the lenders. This facility replaces five bi-lateral facilities aggregating $500 million and includes terms and conditions similar to the facilities it replaced.

In September 2006, Terasen Gas issued $120 million of 30-year medium term note debentures at an interest rate of 5.55%. Funds generated from the issuance of medium term note debentures were used to repay $100 million which matured in the quarter with the remainder available to fund the retirement of a $20 million debenture which is due to mature in the fourth quarter.

As at September 30, 2006, the Company and its subsidiaries had lines of credit in place totaling $1,175 million to finance cash requirements. These lines enable the respective companies to borrow directly from their bankers, issue bankers' acceptances and support commercial paper issuance. Bank lines of $534 million were unutilized at September 30, 2006. Utilized lines are used for short term borrowings and letters of credit. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the Canadian market at rates generally below bank prime. Terasen does not have, nor does it expect to have, any defaults or arrears. The company has thirty eight letters of credit outstanding totaling $117 million.

In addition to the above lines of credit, TGVI on its $350 million credit facility had borrowings outstanding at September 30, 2006 of $284 million. While the borrowings are short-term bankers acceptances, the underlying credit facility on which the advances are provided is committed through to January 2011 and the borrowings are primarily to support the longer term rate base assets of TGVI. Accordingly, a portion of the borrowings have been classified as long term debt in the consolidated balance sheet.

On June 30, 2006, TGVI made a $6.2 million payment on its government loans, of which, approximately $3.7 million was refinanced through borrowings under its $20 million non-revolving credit facility and the remaining amount funded with cash on hand.

No dividends were declared in the first nine months of 2006 compared to $23.8 million in the third quarter of 2005 and $71.2 million in the first nine months of 2005.

FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets as at September 30, 2006 compared to December 31, 2005, other than changes arising from the reclassification of the water and utility services business as a discontinued operation.

Balance Sheet Item	Increase (Decrease) ($ millions)	Explanation
Accounts receivable	$(280.0)	Decrease is mainly due to lower sales of gas in the summer months compared to winter.
Rate stabilization accounts (including current and long term)	163.5	The increase in the net asset position of rate stabilization accounts is mainly due to the fair value mark to market for the gas derivatives. The derivatives are ''out of the money'' and any losses are passed through to customers.
Short-term notes	(157.0)	Decrease is due to the repayment of short-term notes from the refinancing of TGVI and due to the lower debt requirements in the utility operations as a result of the higher equity requirements as rendered by the BCUC decision.
Inventories of gas in storage and supplies	44.0	Increase is mainly due a build up in supply in anticipation for usage in the cooler winter months.

WORKING CAPITAL

Terasen's working capital requirements fluctuate seasonally based on natural gas consumption. Given the regulated nature of its business, Terasen is able to maintain negative working capital balances. Terasen maintains adequate committed credit facilities to meet its working capital requirements. On an annual basis, Terasen generates sufficient cash flow to meet its working capital requirements.

LETTERS OF CREDIT

$117 million of letters of credit were outstanding at September 30, 2006 primarily related to unfunded pension plans and guarantees to third parties for power purchases and on behalf of co-investors in the Express System to fund the Debt Service Account.

CREDIT RATINGS

Following the Kinder Morgan Inc management buyout offer announced in May 2006, both DBRS and Moody's have placed Terasen Inc.'s credit ratings under review with negative implications and possible downgrades. There have been no other changes to the Company's credit ratings from those reported in the annual 2005 Management's Discussion and Analysis.

TRANSACTIONS WITH RELATED PARTIES

The Company estimates that its parent company, Kinder Morgan Inc., provided corporate management services it receives totaling approximately $1.2 million for the three-months ended September 30, 2006. Year to date corporate management service fees were $8.5 million.

FINANCIAL AND OTHER INSTRUMENTS

The Company hedges its exposure to fluctuations in natural gas prices and interest rates through the use of derivative instruments. The table below indicates the valuation of the derivative instruments as at September 30, 2006. For more information on Terasen's derivatives please refer to Terasen's 2005 Annual Management's Discussion and Analysis.

			September 30, 2006		December 31,2005	
Asset (Liability)	**Number of swaps**	**Term to maturity (years)**	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
			(in millions)			
Interest Rate Swaps						
Terasen Inc.	2	2 - 9	$	$ 1.6	$ —	$ 3.6
Terasen Gas[1]	3	2	—	(1.1)	—	(1.6)
TGVI[1]	2	3	—	(0.5)	—	(0.6)
Corridor[1]	2	4 - 9		(0.4)	—	(0.3)
Natural Gas Commodity Swaps Terasen Gas and TGVI[1,2]	263	Up to 3	(162.8)	(176.5)	21.2	105.6

1 The derivatives entered into by Terasen Gas and TGVI relate to regulated operations and any resulting gains or losses are, subject to regulatory approval, passed through to customers in future rates. The derivatives entered into by Corridor are done so on behalf of its shippers and any gains are losses are passed through directly to its shippers.

2 The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

BUSINESS DEVELOPMENT

The following is an update on Terasen's business development activities during the first nine months of 2006. More information on the Company's business development activities is provided in Terasen's 2005 annual Management's Discussion and Analysis.

TERASEN GAS (WHISTLER) (''TGW'') AND TERASEN GAS VANCOUVER ISLAND (''TGVI'')

On June 28, 2006, TGW and TGVI received final approval from the BCUC to extend natural gas service to Whistler. Under the proposed arrangements, TGVI will extend its transmission system to serve TGW by the construction of a 50 kilometre pipeline lateral from Squamish to Whistler and TGW will convert its current piped propane system to natural gas. The pipeline construction is expected to commence in the fall of 2006 and will be co-ordinated with the current Sea to Sky Highway upgrade project. Gas service is expected to be available by November 2008.

CORRIDOR EXPANSION

We have initiated engineering, environmental, consultation and procurement activities on the proposed Corridor pipeline expansion project, as authorized and supported by shipper resolutions and the underlying firm service agreement. The proposed C$1.6 billion expansion includes building a new 42-inch diameter diluent/bitumen (''dilbit'') pipeline, a new 20-inch diameter products pipeline, tankage and upgrading existing pump stations along the existing pipeline system from the Muskeg River Mine north of Fort McMurray to the Edmonton region. The Corridor pipeline expansion would add an initial 180,000 bpd of dilbit capacity to accommodate the new bitumen production from the Muskeg River Mine. An expansion of the Corridor pipeline system has been completed in 2006 increasing the dilbit capacity to 278,000 barrels per day (''bpd'') by upgrading existing pump station facilities. By 2009, the dilbit capacity of the Corridor system is expected to be approximately 460,000 bpd. An application for the Corridor pipeline expansion project was filed with the Alberta Energy Utilities Board and Alberta Environment on December 22, 2005, and approval was received in August 2006. Construction of the Corridor pipeline expansion is expected to begin in November 2006 as the shippers have received definitive approval of their Muskeg River Mine expansion.

TMX

On February 17, 2006, Kinder Morgan Canada filed a complete National Energy Board (''NEB'') application for the Anchor Loop project. On November 15, 2005, Kinder Morgan Canada filed a comprehensive environmental report with the Canadian Environmental Assessment Agency regarding the project. The C$435 million project involves looping a 98-mile section of the existing Trans Mountain pipeline system between Hinton, Alberta, and Jackman, British Columbia, and the addition of three new pump stations. With construction of the Anchor Loop, the Trans Mountain system's capacity will increase from 260,000 bpd to 300,000 bpd by the end of 2008. The public hearing of the application was held the week of August 8, 2006. On October 26, 2006, the NEB released its favorable decision on the application.

RISK ASSESSMENT

The risk profile of Terasen remains substantially unchanged from the profile outlined in Terasen's 2005 Annual Management's Discussion and Analysis.

FORWARD LOOKING STATEMENT

When used in this report, the words ''anticipate'', ''expect'', ''project'', ''believe'', ''estimate'', ''forecast'' and similar expressions are intended to identify forward looking statements, which include statements relating to pending and proposed projects or possible acquisitions. Such statements are subject to certain risks, uncertainties and assumptions pertaining to operating performance, regulatory parameters, economic conditions and, in the case of pending and proposed projects, risks relating to design and construction, regulatory processes, obtaining financing and performance of other parties, including partners, contractors and suppliers and in the case of possible acquisitions, obtaining financing, acquiring assets or companies at an appropriate price and the ability to effect synergies in a timely and cost-effective manner.

ADDITIONAL INFORMATION

Additional information relating to Terasen including its Annual Information Form is available on SEDAR at www.sedar.com.

CERTIFICATE OF FORTIS INC.

Dated: March 7, 2007

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by the securities legislation of each of the provinces of Canada. For the purpose of the Province of Québec, this simplified prospectus, together with documents incorporated herein by reference and as supplemented by the permanent information record, contains no misrepresentation that is likely to affect the value or the market price of the securities to be distributed.

(Signed) H. STANLEY MARSHALL
President and
Chief Executive Officer

(Signed) BARRY V. PERRY
Vice-President, Finance and
Chief Financial Officer

On behalf of the Board of Directors

(Signed) BRUCE CHAFE
Director

(Signed) DAVID G. NORRIS
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: March 7, 2007

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by the securities legislation of each of the provinces of Canada. For the purpose of the Province of Québec, to our knowledge, this simplified prospectus, together with the documents incorporated herein by reference and as supplemented by the permanent information record, contains no misrepresentation that is likely to affect the value or the market price of the securities to be distributed.

CIBC World Markets Inc.

(Signed) David H. Williams

Scotia Capital Inc.

(Signed) John Matovich

TD Securities Inc.

(Signed) Harold R. Holloway

BMO Nesbitt Burns Inc.

(Signed) James A. Tower

RBC Dominion Securities Inc.

(Signed) David Dal Bello

National Bank Financial Inc.

(Signed) Robert B. Wonnacott

Canaccord Capital Corporation

(Signed) Ronald A. Rimer

Beacon Securities Limited

(Signed) Lonsdale W. Holland

HSBC Securities (Canada) Inc.

(Signed) Jeffrey B. Allsop

FORTIS

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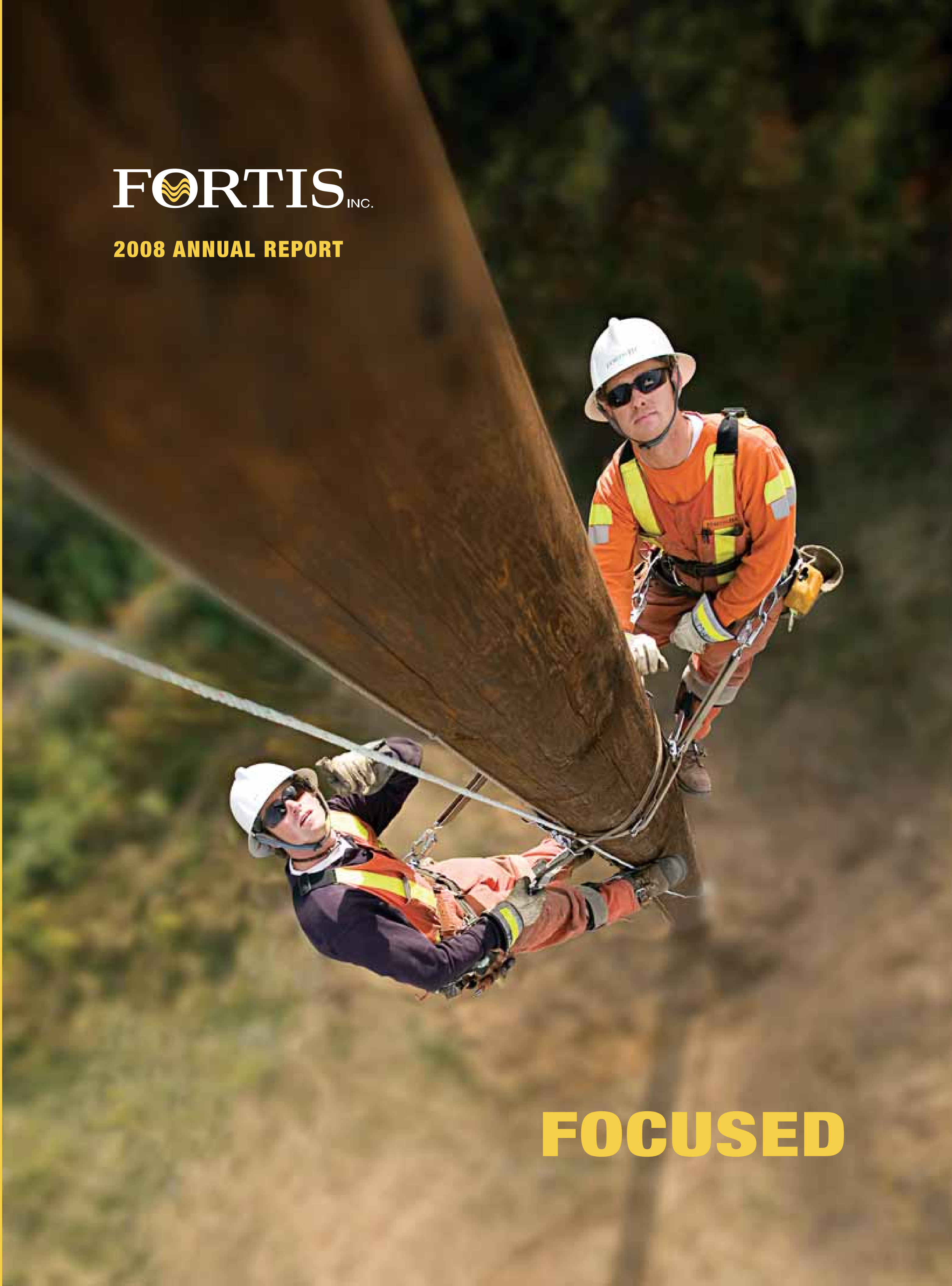
Attachment 84.2

FORTIS INC.

2008 ANNUAL REPORT

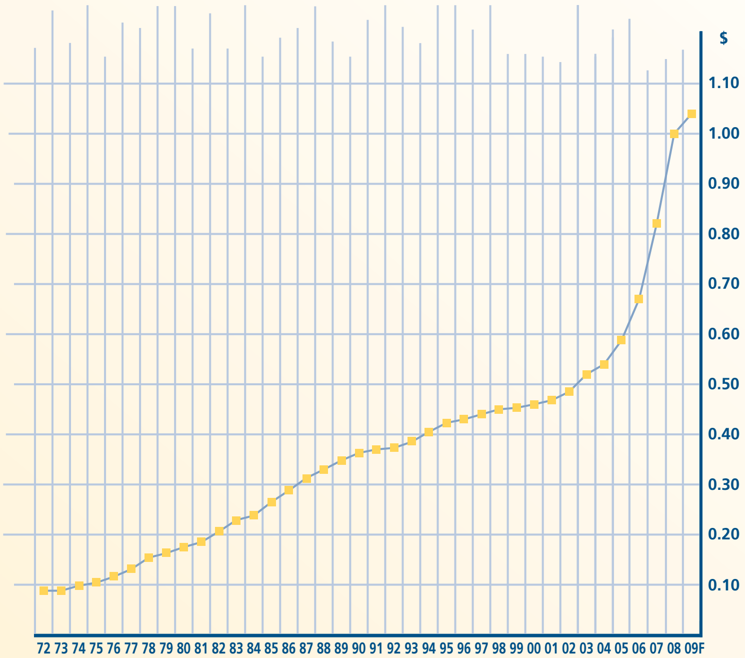


FOCUSED

Fortis Inc. is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers.

Contents

Dividends paid per common share

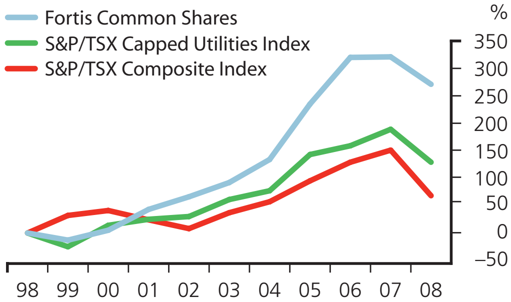


Fortis has increased its annual dividend to common shareholders for 36 consecutive years, the longest record of any public corporation in Canada.

Front Cover Photo: FortisBC employees Matt Wilson (left) and Dan Karslake (right)
Photo taken by Cam Craig, Terasen Gas employee

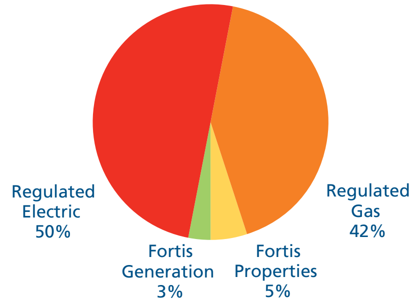
Back Cover Photo: Newfoundland Power Rattling Brook penstock
Photo taken by Gary Murray, Newfoundland Power employee

10-Year Cumulative Total Return



Total Assets Exceed $11 Billion

(as at December 31, 2008)



Regulated Utility Operations

Gas Operations

Terasen *British Columbia*

Electric Operations

FortisAlberta *Alberta*

FortisBC *British Columbia*

Newfoundland Power *Newfoundland*

Maritime Electric *Prince Edward Island*

FortisOntario *Ontario*

Belize Electricity *Belize*

Caribbean Utilities *Grand Cayman*

Fortis Turks and Caicos *Turks and Caicos Islands*

Non-Regulated Operations

Fortis Generation

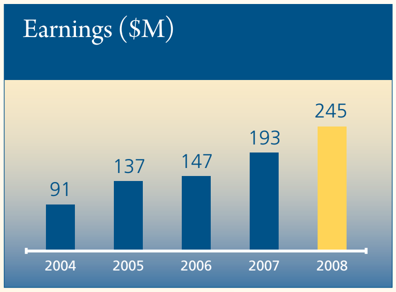
Production Areas
Belize, Ontario, Central Newfoundland, British Columbia, Upper New York State

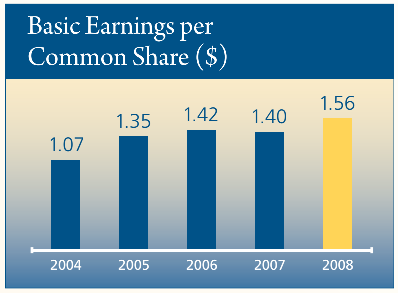
Fortis Properties

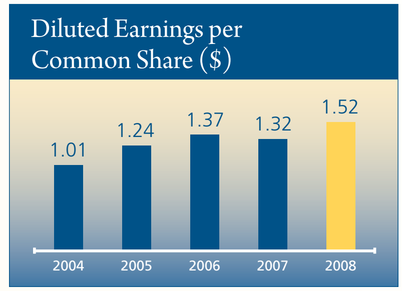
Real Estate
Atlantic Canada, Saskatchewan

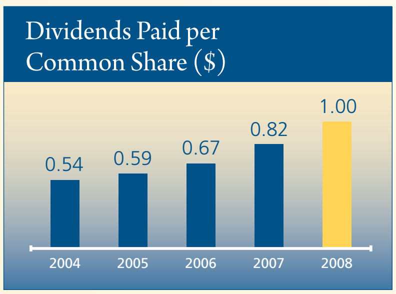
Hotels
Eastern Canada, Manitoba, Saskatchewan, Alberta, British Columbia

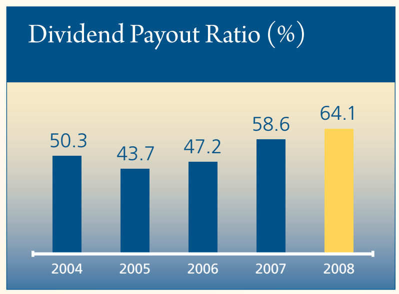
Investor Highlights

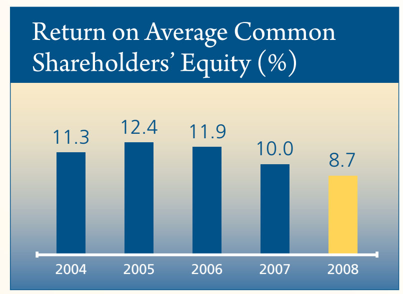


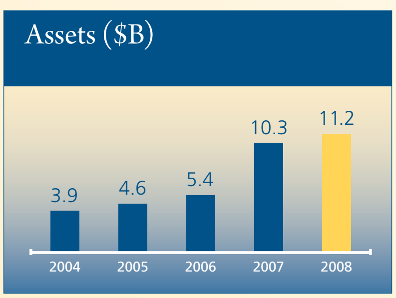


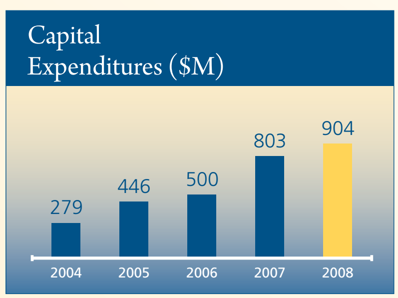


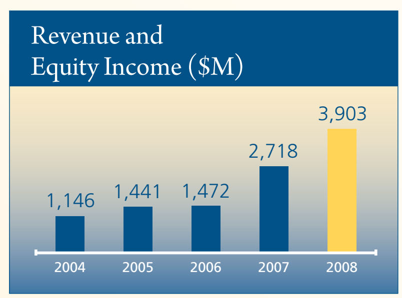


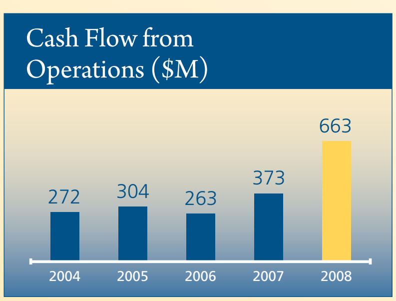


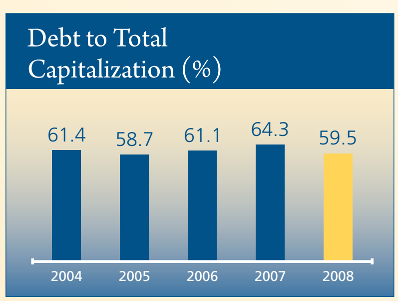


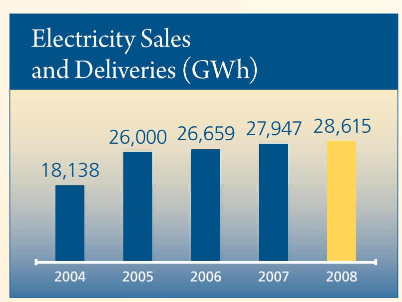












All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2008 unless otherwise indicated.

Regulated

Gas

Terasen[1]	Customers (#)	Employees (#)	Peak Day Demand (TJ)	Gas Volumes (PJ)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B)[2]	Earnings ($M)	Allowed ROE (%)[3] 2008	Allowed ROE (%)[3] 2009
Total	**931,000**	**1,260**	**1,402**	**221**	**220**	**4.6**	**3.1**	**118**	**8.62**	**8.47**

Electric

Company	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B)[2]	Earnings ($M)	Allowed ROE (%)[3] 2008	Allowed ROE (%)[3] 2009
FortisAlberta	461,000	991	3,150	15,722	302	1.8	1.3	46	8.75	8.51[4]
FortisBC	157,000	545	746	3,087	117	1.2	0.9	34	9.02	8.87
Newfoundland Power	236,000	551	1,181	5,208	67	1.0	0.8	32	8.95	8.95
Maritime Electric	73,000	179	223	1,035	35	0.4	0.3	11	10.00	9.75
FortisOntario	52,000	125	227	1,147	11	0.2	0.1	3	9.00	8.39
Belize Electricity[5]	74,000	278	74	407	22	0.2	0.2	(4)	10.00[6]	10.00[6][7]
Caribbean Utilities[8]	24,000	197	94	635	44	0.6	0.4	13	9.00–11.00[6]	9.00–11.00[6]
Fortis Turks and Caicos	9,000	95	29	157	44	0.2	0.2	8	17.50[6][9]	17.50[6]
Total	**1,086,000**	**2,961**	**5,724**	**27,398**	**642**	**5.6**	**4.2**	**143**		

(1) Terasen primarily includes the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc., collectively known as the "Terasen Gas companies".

(2) Forecast mid-year 2009

(3) Rate of return on common shareholders' equity ("ROE"). For Terasen, ROE is for Terasen Gas Inc. ROE for Terasen Gas (Vancouver Island) Inc. is 70 basis points higher.

(4) Interim ROE pending outcome of regulatory proceeding

(5) Information in table represents 100% of Belize Electricity's operations except for earnings data. Earnings represent Belize Electricity's contribution to the consolidated earnings of Fortis, based on the Corporation's 70.1% ownership interest.

(6) Regulated rate of return on rate base assets ("ROA")

(7) Based on the June 2008 Final Decision on Belize Electricity's 2008/2009 rate application

(8) Fortis holds a 57% interest in Caribbean Utilities. Information in table represents 100% of Caribbean Utilities' operations as at and for the 14 months ended December 31, 2008 due to a change in the utility's fiscal year end. Earnings represent Caribbean Utilities' contribution to the Corporation's consolidated earnings for the 14 months ended December 31, 2008.

(9) Significant investment is currently occurring at the utility. 2008 achieved ROA was lower than the ROA allowed under the licence.

Non-Regulated

Fortis Generation[1]

	Generating Capacity (MW)	Energy Sales (GWh)	Assets[3] ($B)	Earnings[4] ($M)	Capital Program ($M)
Total	**195**	**1,217**	**0.4**	**30**	**28**

Fortis Properties[2]

	Employees (#)	Assets ($B)	Earnings[4] ($M)	Capital Program ($M)
Total	**2,000**	**0.6**	**23**	**14**

(1) Includes operations in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State

(2) Includes approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada and 20 hotels across Canada

(3) Includes $126 million in "Other" non-regulated assets

(4) Contribution to Fortis Inc. consolidated earnings for the fiscal year ended December 31, 2008

Information is for the fiscal year ended December 31, 2008 unless otherwise indicated.

Left – The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines and met a peak day demand of 1,402 TJ in 2008.

Right – Fortis electric utilities own and/or operate approximately 136,000 kilometres of transmission and distribution lines and met a combined peak demand of more than 5,700 MW in 2008.

Report to Shareholders

2008 has been another successful year for your company and marks the 9th consecutive year Fortis has delivered record earnings to shareholders.

Fortis achieved net earnings applicable to common shares of $245 million, 27 per cent higher than earnings of $193 million in 2007. Earnings per common share were $1.56, 16 cents higher than earnings per common share of $1.40 for the previous year.

Growth in earnings, excluding one-time items, was primarily attributable to a full year of earnings from Terasen and increased contributions from non-regulated hydroelectric generation. Earnings in 2008 were enhanced by a one-time $7.5 million tax reduction ($5.5 million at the Terasen Gas companies and $2 million at Terasen Inc.) associated with the settlement of historical corporate tax matters at Terasen but were reduced by a one-time $13 million charge that represented the Corporation's share of fuel and purchased power costs disallowed by Belize Electricity's regulator.

Dividends paid per common share grew to $1.00 in 2008, 22 per cent higher than 82 cents paid per common share in the previous year. The dividend payout ratio was approximately 64 per cent in 2008. Fortis increased its quarterly common share dividend to 26 cents, commencing with the first quarter dividend paid in 2009. The 4 per cent increase in the quarterly common share dividend translates into an annualized dividend of $1.04 and extends the Corporation's record of annual common share dividend increases to 36 consecutive years, the longest record of any public corporation in Canada.

In December, Fortis amended and restated its Dividend Reinvestment and Share Purchase Plan to provide shareholders with a 2 per cent discount on the purchase of common shares, issued from treasury, with reinvested dividends. The discount became effective with dividends paid on March 1, 2009.

Over the past five years, Fortis delivered an average annualized total return of 14.3 per cent, the highest in its sector, and outperformed both the S&P/TSX Capped Utilities Index and S&P/TSX Composite Index, which delivered average annualized total returns of 7.3 per cent and 4.2 per cent, respectively, over that period.

In October 2008, Fortis was placed in the S&P/TSX 60, 60 Capped and Equity 60 indices. The average daily trading volume for the 46 trading days in 2008 that Fortis was a member of these indices was approximately 662,000 common shares, almost 35 per cent higher than the average daily trading volume for the year-to-date period prior to inclusion. Over the past five years, the average daily trading volume of Fortis common shares has increased 4.5 times, exceeding, on average, 525,000 common shares traded daily in 2008.

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. At the end of 2008, regulated rate base assets approached $7 billion; total assets of Fortis exceeded $11 billion, more than five times the amount five years ago. Growth has been driven by two large acquisitions: the $3.7 billion acquisition of Terasen in May 2007 and the $1.5 billion acquisition of FortisAlberta and FortisBC in May 2004. As well, growth has occurred organically through the continued investment in energy infrastructure. Over the past five years, Fortis utilities have invested approximately $2.9 billion in capital projects to ensure reliability of service to customers and meet growth in energy demand.

Left – Fortis, through its regulated and non-regulated businesses, owns and/or operates more than 1,800 MW of generation, mainly hydroelectric.
Right – The regulated utilities of Fortis serve more than 2,000,000 customers in five Canadian provinces and three Caribbean countries.

Report to Shareholders

2008 marked the largest annual capital investment program in the history of Fortis. Consolidated capital expenditures, before customer contributions, were $904 million. Much of this investment was driven by the Terasen Gas companies, FortisAlberta, FortisBC and regulated and non-regulated electric utility operations in the Caribbean. Terasen Gas (Vancouver Island) started construction of its approximate $200 million liquefied natural gas storage facility, which will enhance reliability of supply to customers when it comes into service in late 2011. FortisAlberta continued work on its four-year Automated Meter Infrastructure Project, estimated at a total cost of $124 million, which will enable customers to better monitor and manage energy consumption. FortisBC received regulatory approval to proceed in 2009 with the $141 million Okanagan Transmission Reinforcement Project, the largest capital initiative ever to be undertaken by the utility. The project will provide needed system enhancements in the Okanagan region and help ensure the delivery of safe, reliable energy to customers. Construction continued on the US$53 million 19-megawatt ("MW") Vaca hydroelectric generating facility in Belize. When it comes online, expected at the beginning of 2010, the amount of energy Belize Electricity sources from hydroelectricity, the least-cost source of energy supply available, will increase to approximately 45 per cent.

The Terasen acquisition became accretive to earnings per common share of Fortis in the first quarter of 2008. The Terasen Gas companies contributed $118 million to earnings for the full year in 2008 compared to $50 million for the 7½ months of ownership in 2007. Results for 2008 were favourably impacted by an approximate $5.5 million tax reduction related to the settlement of historical corporate tax matters and a higher allowed rate of return on common shareholder's equity ("ROE") compared to 2007. Results for 2007 included a $7 million after-tax gain on the sale of surplus land.

Canadian Regulated Electric Utilities contributed earnings of $126 million compared to $125 million for 2007. Earnings grew $5 million year over year, excluding the impact of a one-time gain of $2 million in 2007 associated with an interconnection agreement-related refund at FortisOntario and the subsequent regulator-required repayment of the refund in 2008 by the utility. The key performance drivers were rate base growth and the higher allowed ROEs at FortisAlberta, FortisBC and Newfoundland Power, partially offset by lower corporate tax recoveries at FortisAlberta.

Customer rates for 2009 have been approved for the four largest utilities, which account for approximately 77 per cent of the total assets of Fortis. The allowed ROEs for 2009 at Terasen Gas Inc. and FortisBC declined slightly to 8.47 per cent and 8.87 per cent, respectively. The allowed ROE for 2009 at Newfoundland Power remains at 8.95 per cent. FortisAlberta is currently engaged in a generic cost of capital proceeding with its regulator and a decision on the utility's allowed ROE for 2009 is not expected until later in the year. In the interim, as directed by its regulator, customer rates for 2009 at FortisAlberta have been set using the utility's allowed ROE for 2007 of 8.51 per cent.

Caribbean Regulated Electric Utilities contributed earnings of $17 million compared to $31 million for 2007. Earnings were $3 million lower year over year, excluding the impact of a one-time loss of $13 million in 2008 related to a regulatory order received at Belize Electricity, which is being legally contested by the Company, and a one-time loss of $2 million in 2007 associated with the disposal of steam-turbine assets at Caribbean Utilities. Overall electricity sales growth and two additional months of earnings from Caribbean Utilities, associated with a change in the utility's fiscal year end, were more than offset by the impact of a 3.25 per cent reduction in base electricity rates at Caribbean Utilities, effective January 1, 2008; a lower allowed rate of return on rate base assets ("ROA") at Belize Electricity; and an approximate $2 million revenue loss at Fortis Turks and Caicos associated with Hurricane Ike.

Over the past five years, Fortis utilities have invested approximately $2.9 billion in capital projects to ensure reliability of service to customers and meet growth in energy demand.

Report to Shareholders

Non-Regulated Fortis Generation contributed earnings of $30 million, $6 million higher than for 2007. Performance was driven by increased hydroelectric production in central Newfoundland, Belize and Upper New York State, as a result of higher rainfall, and higher average wholesale energy prices in Upper New York State and Ontario.

Commencing in May 2009, Fortis will no longer have the benefit of the 75-MW Rankine generating facility in Ontario due to the expiration of the water rights on the Niagara River. However, earnings' projections for Vaca, combined with the planned substantial consolidated capital program over the next couple of years, are expected to more than offset the loss of earnings associated with the expiry of the Rankine water rights.

Fortis Properties delivered earnings of $23 million compared to $24 million for 2007. Excluding a $2 million favourable tax adjustment in 2007, earnings were $1 million higher year over year, mainly due to a full year of earnings from Delta Regina, which was acquired in August 2007.

Fortis continues to maintain strong investment-grade credit ratings, allowing it to have good access to the debt capital markets. Fortis is rated A– by Standard & Poor's and BBB(high) by DBRS. Its four largest utilities all have strong investment-grade credit ratings.

Fortis and its subsidiaries raised almost $1.2 billion in the capital markets in 2008. In December, the Corporation completed a $300 million common share issue, the net proceeds of which were used to repay short-term debt primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008 and for general corporate purposes. In the second quarter of 2008, Fortis issued preference shares for gross proceeds of $230 million, the net proceeds of which were mainly used to repay $170 million borrowed under the Corporation's committed credit facility and to fund subsidiary equity requirements. Canadian Regulated Utilities issued $660 million of 30-year long-term debt at rates ranging from 5.80 per cent to 6.05 per cent. The proceeds provide long-term funding for capital programs to enhance reliability of gas and electricity service and meet customer growth.

At December 31, 2008, Fortis had consolidated credit facilities of $2.2 billion, of which $1.5 billion was unused. Approximately $2 billion of the total credit facilities are committed facilities, the majority of which have maturities ranging from 2011 to 2013. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities. The Corporation's long-term debt maturities and repayments are expected to average approximately $180 million annually over the next five years. With its substantial credit facilities and conservative capital structure, we believe Fortis has the financial flexibility to respond to the global economic downturn and volatility in the capital markets anticipated to continue in 2009.

Employee success underpins corporate success. To each of our more than 6,200 employees, thank you for your commitment to customers. We extend our appreciation to the Board of Directors of Fortis for your governance and counsel. We also offer our gratitude and best wishes to Dr. Linda Inkpen who retires from the Board in 2009.

Left – The Fortis Emergency Response Network, consisting of more than 60 employees throughout the Fortis Group of Companies, assisted Fortis Turks and Caicos with its restoration efforts following Hurricane Ike, a Category 4 hurricane.

Right – Geoffrey F. Hyland, Chair of the Board, Fortis Inc. (left) and Stan Marshall, President and CEO, Fortis Inc. (right)

Report to Shareholders

Fortis is focused on executing its 2009 consolidated capital program, estimated at approximately $1 billion, to meet customers' expectations and growth in energy demand. Over the next five years, the consolidated capital expenditure program is expected to be approximately $4.5 billion, substantially all of which will be funded at the subsidiary level. This capital investment, which will mainly occur in western Canada, will add value for customers and shareholders and fortify the position of Fortis as a leading owner of energy infrastructure in Canada.

On behalf of the Board of Directors,

Geoffrey F. Hyland
Chair of the Board
Fortis Inc.

H. Stanley Marshall
President and Chief Executive Officer
Fortis Inc.

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

The Corporation will continue to focus on three primary objectives:

i) The growth in assets and market capitalization should be greater than the average of other North American public gas and electric utilities of similar size.

ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.

iii) The financial and business risks of Fortis should not be substantially greater than those associated with the operation of a North American utility of similar size.

Left – Officers of Terasen (back row l-r): Douglas Stout, VP, Marketing and Business Development; Dwain Bell, VP, Distribution; Robert Samels, VP, Business Services and CIO; Cynthia Des Brisay, VP, Gas Supply and Transmission; Roger Dall'Antonia, VP, Corporate Development and Treasurer; (front row l-r): Scott Thomson, VP, Regulatory Affairs and CFO; Jan Marston, VP, HR and Operations Governance; Randall Jespersen, President and CEO; David Bennett, VP, Regulatory Affairs and General Counsel

Right – Terasen began construction on the approximate $200 million 1.5 billion-cubic foot Mount Hayes liquefied natural gas storage facility on Vancouver Island in May 2008.

Terasen

Regulated Gas Operations

Terasen Inc. ("Terasen") is the largest distributor of natural gas in British Columbia, serving 931,400 customers in more than 125 communities or 96 per cent of gas users in the province. The Company delivers more than 20 per cent of the total energy consumed in British Columbia, comparable to the amount of electricity used in the province, making it a significant contributor to the province's energy mix.

Terasen's regulated natural gas and piped-propane distribution business is carried out by Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), collectively known as the "Terasen Gas companies". Its operations also include Terasen Energy Services, which designs, owns and operates geothermal systems, community piping and energy-transfer systems to harness renewable energy sources.

TGI, the largest subsidiary of Terasen, provides natural gas transmission and distribution services and propane distribution to approximately 834,000 customers. Its service territory extends from Vancouver to the Fraser Valley and the interior of British Columbia. TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast. The Company serves approximately 95,000 customers. TGWI owns and operates the propane distribution system in Whistler, providing service to approximately 2,400 customers.

The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines. In 2008, gas volumes exceeded 221,000 terajoules ("TJ") and a peak day demand of 1,402 TJ was met.

Terasen achieved an all-time high Customer Satisfaction Rating of 79.7 per cent in 2008. The Company has improved its Customer Satisfaction Rating for each of the past five years.

Approximately $220 million, before customer contributions, was invested in capital programs in 2008 to ensure the safe, reliable delivery of piped energy to customers.

Construction started on the approximate $200 million 1.5 billion-cubic foot Mount Hayes liquefied natural gas storage facility on Vancouver Island in May 2008. The facility will allow for more efficient use of existing pipeline systems and improve reliability and security of supply during periods of system interruptions or increased energy demand. It is expected to come into service by late 2011.

Construction continued on the 50-kilometre natural gas pipeline from Squamish to Whistler. The pipeline, a key component of the Sustainable Energy Plan of the Resort Municipality of Whistler, is expected to be completed in spring 2009, followed by the conversion of the community's propane system. The total cost of the pipeline and conversion is expected to be approximately $51 million.

Completed under budget and almost two months ahead of schedule, the $24 million Vancouver Low-Pressure Replacement Project concluded with the seismic upgrade of 95 kilometres of natural gas distribution pipelines and 7,100 service connections. In addition to ensuring the safety and integrity of the gas distribution system, the project enhances delivery service by accommodating modern high-efficiency appliances.

Left – The four-year Automated Meter Infrastructure ("AMI") Project, estimated at a total capital cost of $124 million, entails the scheduled replacement of conventional meters with AMI technology for all FortisAlberta customers by the end of 2010.

Right – Officers of FortisAlberta (l-r): Annette Butt, VP, Human Resources and Corporate Communications; Cynthia Johnston, VP, Regulatory and Legal; Karl Smith, President and CEO; Nipa Chakravarti, VP, Customer Service; Alan Skiffington, VP, Business Services and CIO; Ian Lorimer, VP, Finance and CFO; Phonse Delaney, VP, Operations and Engineering

FortisAlberta

Regulated Electric Operations

FortisAlberta is an electric utility that distributes electricity, generated by other market participants, to end-use customers in southern and central Alberta. Its electricity system includes approximately 108,000 kilometres of distribution lines, which comprise more than 60 per cent of Alberta's total electricity distribution network. The Company serves approximately 461,000 customers in 175 communities and met a peak demand of 3,150 MW in 2008.

FortisAlberta achieved a Customer Satisfaction Rating of 81 per cent in 2008, a marked improvement from its average annual rating for the past three years of 76 per cent.

A record $302 million, before customer contributions, was invested in capital assets in 2008, primarily to meet growth in customer demand. More than 12,000 new customers were connected to the utility's distribution system. The Company worked closely with the transmission service provider and the Alberta Electric System Operator to add substation capacity, improve reliability and meet customer load growth in Balzac, Tilley, Stavely, Bruderheim and Blackfalds.

The Automated Meter Infrastructure ("AMI") Project involved the installation of more than 70,000 electronic meters at customer sites in 2008. AMI technology, which replaces the manual meter reading system, will help reduce operating costs and enable customers to better monitor and manage their energy usage on a monthly basis. The four-year AMI Project, estimated at a total capital cost of $124 million, entails the scheduled replacement of conventional meters with AMI technology for all FortisAlberta customers by the end of 2010.

Approximately $50 million was invested in projects to improve system reliability, customer service and safety. Projects included the replacement of more than 4,000 deteriorated poles, the installation of distribution automation equipment in Airdrie and St. Albert to enable fast restoration of service following an outage and the introduction of new technology that involves the injection of silicone to extend the service life of underground cables.

Construction was completed on the utility's $26 million 88,000-square foot operations and customer service facility in Airdrie. The new facility houses approximately 30 per cent of FortisAlberta's workforce, previously located in leased office space in Calgary. The Company earned the City of Airdrie's 2008 Eco Edge Award as a result of environmental leadership at the new facility, which features innovative environmental considerations including a 95,000-litre rainwater cistern and energy-efficient windows and lighting.

As a result of productivity improvements, FortisAlberta achieved an operating cost per customer of $209 compared to $216 in 2007. Better performance was achieved as a result of revised work practices to improve the time to complete projects and enhance work capacity. New conductor installation equipment helped improve field work practices, resulting in increased efficiency and higher quality of work. Efficiencies were also created through the utility's ability to assign resources, bundle work and reduce employee travel time.

The Company implemented an environmental management system consistent with the international ISO 14001 standard. The system and related training initiatives provide a new tool to manage environmental issues and improve operational performance.

Left – Officers of FortisBC (l-r): David Bennett, VP, Regulatory Affairs, General Counsel and Corporate Secretary; Michele Leeners, VP, Finance and CFO; John Walker, President and CEO; Don Debienne, VP, Power Supply and Strategic Planning; Doyle Sam, VP, Engineering and Operations; Michael Mulcahy, VP, Customer and Corporate Services

Right – FortisBC invested approximately $117 million, before customer contributions, in capital projects in 2008 to meet growing energy demand and replace aging infrastructure.

FortisBC

Regulated Electric Operations

FortisBC is an integrated electric utility operating in the southern interior of British Columbia, serving more than 157,000 customers directly and indirectly. Its utility assets include approximately 7,000 kilometres of transmission and distribution lines and four regulated hydroelectric generating plants on the Kootenay River with a combined capacity of 223 MW. The annual gross energy entitlement from the plants is about 1,591 gigawatt hours ("GWh"). FortisBC also manages 904 MW of hydroelectric generation through contract services. It generates approximately 45 per cent of its electricity requirements, with the balance met through power purchase agreements. The Company met a record peak demand of 746 MW in 2008, exceeding the previous record of 718 MW reached in 2006.

FortisBC achieved a Customer Satisfaction Rating of 86 per cent in 2008, consistent with its rating in 2007.

An intense wind storm swept through the utility's service territory in July, causing power outages to approximately 25,000 customers. More than 150 employees, including power-line technicians, call centre and system control centre personnel and meter readers, were involved in safely restoring power to the majority of customers within 24 hours. Call centre personnel fielded more than 5,000 calls during one storm day, ten times the normal daily call volume.

FortisBC is focused on providing the highest level of customer service and ensuring the timely and cost-efficient installation of new service connections. In 2008, 454 residential extension quotes were processed and 1,664 new service installations were completed. Electronic billing (eBills) was introduced, with more than 6,400 customers choosing to receive their electricity bills this way.

In 2008, approximately $117 million, before customer contributions, was invested in capital projects to meet growing energy demand and replace aging infrastructure. Construction was completed on the $6.2 million Ootischenia substation, creating an additional source of power supply to the Castlegar area in the West Kootenays. The new substation at Big White ski area, the final phase of the $20.5 million Big White Project, was commissioned and the $27 million Kettle Valley Substation Project in Rock Creek was energized. Work began on the $14.4 million Black Mountain substation and associated distribution line, servicing growth to areas northeast of Kelowna. The first phase of the $17.2 million Ellison Substation Project in Kelowna began with the upgrading of six kilometres of distribution and transmission lines.

Approximately $11 million was invested in the utility's ongoing hydroelectric generation Upgrade and Life-Extension Program. The program, which involves rebuilding 11 of the 15 hydroelectric generating units in the Company's four generating stations, is expected to be completed in 2012. The program will improve efficiency, safety and environmental stewardship and maintain the overall reliability of the plants.

Regulatory approval was received in 2008 for the $141 million Okanagan Transmission Reinforcement Project, the largest capital project to be undertaken by FortisBC. The project entails upgrades to the utility's existing transmission lines and substations and the building of a new 230-kilovolt ("kV") transmission line and substation. It will provide needed system enhancements in the Okanagan area, ensuring customers have safe and reliable energy as residential and business growth continues in the region. Construction is scheduled to commence spring 2009 with completion in mid-2011.

Left – Newfoundland Power achieved a Customer Satisfaction Rating of 89 per cent in 2008.

Right – Officers of Newfoundland Power (l-r): Jocelyn Perry, VP, Finance and CFO; Gary Smith; VP, Engineering and Operations; Earl Ludlow, President and CEO; Lisa Hutchens, VP, Customer Relations and Corporate Services; Peter Alteen, VP, Regulatory Affairs and General Counsel

Newfoundland Power

Regulated Electric Operations

Newfoundland Power operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves approximately 236,000 customers or 85 per cent of electricity consumers in the province. It owns and operates 30 small generating stations with an installed generating capacity of approximately 140 MW, of which 97 MW is hydroelectric generation, and has approximately 11,000 kilometres of transmission and distribution lines. Newfoundland Power met a peak demand of 1,181 MW in 2008. Approximately 92 per cent of its energy requirement is purchased from Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro").

Despite the impact to customers of rising energy prices, Newfoundland Power achieved a Customer Satisfaction Rating of 89 per cent in 2008, slightly higher than the rating achieved in the previous year. Strategic capital investments and employee commitment to customer service enabled electricity to be delivered to customers 99.97 per cent of the time in 2008.

Approximately $67 million, before customer contributions, was invested in capital projects to help strengthen the electricity system, including $18.3 million to provide service to new customers. The Company invested $1.5 million and worked jointly with Newfoundland Hydro and two independent developers to connect 54 MW of renewable wind energy to the island's electricity system. To further enhance system reliability, Newfoundland Power completed a $3.4 million upgrade of the transmission lines on the Bonavista Peninsula and Southern Shore of the Avalon Peninsula and refurbished several of its substations across the island at a total cost of $2.4 million. Performance optimization of 43 distribution feeders in high-growth areas was undertaken to prevent power outages and the use of handheld computers was increased to streamline maintenance workflow.

The Company partnered with Newfoundland Hydro to provide customers with the information, tools and programs they need to be energy efficient. The two utilities completed a Five-Year Energy-Conservation Plan with the goal of conserving an estimated 70 GWh of energy annually through 2013, scheduled to begin in 2009. Newfoundland Power became an active partner in the Energy Conservation and Efficiency Partnership under the Government of Newfoundland and Labrador's Energy Plan, coordinating and assisting with energy conservation and efficiency initiatives.

Online connection with customers improved throughout the year. Customer visits to the corporate website increased 20 per cent over the previous year.

Newfoundland Power completed its first year under the internationally recognized OHSAS 18001 Health and Safety Management System standard. Safety education, training and awareness initiatives included comprehensive employee programs dealing with hazard assessment through risk management/job planning, high-voltage electricity switching and safe work practices around de-energized equipment. The Company launched a new contractor website, which provides easy online access to safety training requirements, practices and policies. Electrical safety presentations were delivered to more than 2,600 children in 53 schools throughout the province. Newfoundland Power delivered safety training to 190 firefighters across the island and training was provided to members of the Canadian military in preparation for their power-restoration efforts in Afghanistan.

Left – Officers of Maritime Electric (l-r): John Gaudet, VP, Corporate Planning and Energy Supply; Steve Loggie, VP, Customer Service; Fred O'Brien, President and CEO; Bill Geldert, VP, Finance, CFO and Corporate Secretary

Right – Maritime Electric serves approximately 73,000 customers, or 90 per cent of electricity consumers, on Prince Edward Island.

Maritime Electric

Regulated Electric Operations

Maritime Electric, the principal electric utility on Prince Edward Island ("PEI" or the "Island"), serves approximately 73,000 customers or 90 per cent of electricity consumers in the province. The Company owns and operates a fully integrated system comprised of approximately 5,300 kilometres of transmission and distribution lines, providing for the generation, transmission and distribution of electricity throughout the Island. Maritime Electric maintains on-Island generating facilities at Charlottetown and Borden-Carleton with a combined total capacity of 150 MW. The electricity system is connected to the mainland power grid via two submarine cables under the Northumberland Strait. The utility met a peak demand of 223 MW in 2008.

Maritime Electric purchases approximately 87 per cent of the energy required to serve customers from New Brunswick Power ("NB Power"). It has entitlement to energy and capacity from NB Power's Point Lepreau and Dalhousie Generating Stations through agreements that extend for the life of these stations.

In April 2008, a refurbishment began on the Point Lepreau Generating Station that will extend its life by 25 years and provide additional stability with respect to long-term energy supply. The balance of the Company's energy requirements is obtained from on-Island wind-powered generation facilities and from the utility's own generating plants. Approximately 13 per cent of total energy supply was derived from wind-powered generation in 2008.

The Government of Prince Edward Island requires Maritime Electric to have a total of 30 per cent of its annual energy sales sourced from on-Island wind farms by 2013. The Company is working with the Government of Prince Edward Island and PEI Energy Corporation on the development of additional wind-powered generation. It is expected that a request for proposal for the additional wind-powered energy expansion will be issued by the provincial government by mid-2009.

Approximately $35 million, before customer contributions, was invested in capital projects to improve system reliability and customer service. Construction continued on the $14 million 138-kV transmission line and power corridor in western PEI. The 71-kilometre transmission line will deliver wind-powered energy from current and future commercial operations in western PEI to the North American grid. The power corridor, which will be jointly funded by the Government of Prince Edward Island and SUEZ Energy North America, will facilitate further expansion of wind-powered generation.

Despite the impact of high world fossil fuel prices on the cost of energy purchased to meet the Island's energy demand, Maritime Electric achieved a Customer Satisfaction Rating of 80 per cent in 2008 compared to 73 per cent for the previous year. Several customer service initiatives were completed in 2008, including an upgrade of the Company's website. A number of new and improved website features were added, such as the Energy Calculator, which will assist customers in better understanding and managing their electricity consumption.

Left – By mid-2009, FortisOntario is scheduled to begin the installation of smart meters, which track time-of-use consumption data.

Right – Officers of FortisOntario (l-r): Scott Hawkes, VP, Corporate Services, General Counsel and Corporate Secretary; Glen King, VP, Finance and CFO; William Daley, President and CEO; Angus Orford, VP, Operations

FortisOntario

Regulated Electric Operations

FortisOntario is an integrated electric utility which owns and operates Canadian Niagara Power and Cornwall Electric and serves approximately 52,000 customers, mainly in Fort Erie, Port Colborne, Cornwall and Gananoque, Ontario. Its regulated assets include approximately 1,570 kilometres of distribution and transmission lines in the Niagara and Cornwall regions, including an international interconnection between New York State and Fort Erie. FortisOntario owns a 10 per cent interest in Westario Power Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies that together serve more than 27,000 customers. The Company purchases its electricity from the Independent Electricity System Operator in Ontario, with the exception of Cornwall Electric which is supplied by Hydro-Québec. FortisOntario met a combined peak demand of 227 MW in 2008.

In October 2008, the Company entered into a definitive agreement to acquire a 10 per cent strategic ownership in the electricity distribution business of Grimsby Power Inc., which serves approximately 10,000 distribution customers in the western area of the Niagara region. The transaction has been approved by the Ontario Energy Board ("OEB") and is pending approval from the Ontario Ministry of Finance.

The Company achieved an overall Customer Satisfaction Rating of 84 per cent in 2008, slightly higher than its rating for the previous year. Customers continue to rate the utility's reliability/safe delivery of electricity and quality of service at 91 per cent and 88 per cent, respectively.

FortisOntario again exceeded performance standards set by the OEB with respect to response times, service connections and call answer statistics. OEB standards will be expanded in 2009 and the Company will ensure all reporting requirements are met.

FortisOntario undertook two electricity conservation and demand management programs during the year. Almost 700 customers enrolled in the Summer Sweepstakes Program, which encouraged customers to reduce their electricity consumption by 10 per cent in July and August.

The Company invested $11 million, before customer contributions, in capital projects involving new service connections and rebuild projects designed to improve the safety and reliability of its distribution systems. In Port Colborne, construction began on a new $1.5 million substation that will support load growth and replace an existing substation near the end of its useful life.

The Government of Ontario has mandated all regulated electric utilities in the province to install smart meters, which track time-of-use consumption data, at customer sites by the end of 2010. During 2008, FortisOntario selected a supplier of smart meters and installation of this new technology is scheduled to begin by mid-2009. Approximately 27,000 of the utility's metered customers will move to time-of-use rates by the end of 2010.

Left – Officers of Belize Electricity (l-r): Juliet Estell, Manager, Executive Services and Company Secretary; Curtis Eck, VP, Customer Care and Operations; Lynn Young, President and CEO; Rene Blanco, VP, Finance & Administration and CFO; Joseph Sukhnandan, VP, Engineering and Energy Supply

Right – Belize Electricity earned a record Customer Satisfaction Rating of 86 per cent in 2008.

Belize Electricity

Regulated Electric Operations

Belize Electricity is the primary distributor of electricity in Belize, Central America. Serving approximately 74,000 customers, the utility met a peak demand of 74 MW in 2008 from multiple sources of energy, including power purchases from Belize Electric Company Limited ("BECOL"), Comisión Federal de Electricidad ("CFE") (the Mexican state-owned power company), Hydro Maya Limited and its own diesel-fired and gas-turbine generation. All major load centres are connected to the country's national electricity system, which is interconnected with the Mexican national electricity grid, allowing the Company to optimize its power supply options. Belize Electricity has an installed generating capacity of 34 MW and owns approximately 2,840 kilometres of transmission and distribution lines. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

The ability of Belize Electricity to meet the energy needs of its customers was significantly challenged by regulatory decisions received in 2008. During the year, the Company was forced to delay several planned initiatives aimed at system expansion and improvement as a result of a US$12.5 million limit on capital expenditures imposed by the Public Utilities Commission of Belize.

While regulatory approval was granted in the latter part of the year to complete rural electrification projects and build interconnection facilities to connect with new generation sources, cash flow challenges continued to restrict Belize Electricity's ability to proceed with these projects and other key capital works. Revisions were made to various project schedules to reflect the capital work suspensions, including the construction of substations to connect with independent power producers, now scheduled for completion in the second quarter in 2009.

The Company invested approximately $22 million, before customer contributions, in capital expenditures in 2008. Projects completed during the year included the connection of several rural communities in the Belize and Cayo Districts to the national grid and the construction of an alternate feeder to serve the popular tourist destination of Placencia Village in Southern Belize. The new feeder will address Placencia's load growth, provide an alternate distribution line to the service area and enable service upgrades with fewer interruptions. A US$2 million mobile substation was also procured to maintain service while substation repairs and maintenance are being carried out.

The Company signed a revised Power Purchase Agreement ("PPA") with CFE during the year. Under the revised contract, Belize Electricity has the option to purchase up to 50 MW of energy at a firm rate with the option to purchase the 50 MW of energy at an economic rate if available and less expensive. The utility also signed a PPA with Belize Aquaculture Limited for the supply of approximately 15 MW of power sourced from a heavy fuel oil-fired generating facility in Southern Belize. Connection to the utility's electricity system, which is expected to occur in the second quarter of 2009, will enable the facility to provide backup power to improve system reliability. It will also reduce reliance on Belize Electricity's diesel generators, which are more costly to operate.

Despite the significant operational constraints imposed as a result of the regulatory decisions received, the Company earned a record Customer Satisfaction Rating of 86 per cent in 2008. Several improvement initiatives focused on enhancing service delivery. Operational regions were defined and a service-order management team was established to ensure customer requests are met expeditiously. As well, several new line vehicles were purchased and deployed to various load centres as necessary.

Left – Caribbean Utilities' electricity system has an installed generating capacity of approximately 137 MW and the Company met a record peak demand of 94 MW in 2008.

Right – Officers of Caribbean Utilities (l-r): Douglas Murray, Corporate Secretary; David Watler, VP, Production; Letitia Lawrence, VP, Finance and CFO; Richard Hew, President and CEO; Andrew Small, VP, Transmission and Distribution

Caribbean Utilities

Regulated Electric Operations

Caribbean Utilities generates, transmits and distributes electricity to more than 24,000 customers on Grand Cayman, Cayman Islands. The utility owns and operates approximately 555 kilometres of transmission and distribution lines and 24 kilometres of high-voltage submarine cable. Its electricity system has an installed generating capacity of approximately 137 MW and the Company met a record peak demand of 94 MW in 2008.

The Class A Ordinary Shares of Caribbean Utilities are listed in US funds on the Toronto Stock Exchange under the symbol CUP.U. Fortis has an approximate 57 per cent controlling ownership interest in the utility.

Caribbean Utilities is one of the most reliable and efficient utilities in the Caribbean region. A Customer Satisfaction Rating of 90 per cent was achieved in 2008 compared to 84 per cent in 2007. For the six-month period ended October 31, 2008, an Average Service Availability Index of 99.9 per cent was posted, with customers experiencing, on average, a total of less than one hour of outages for that period.

The Company successfully completed a Class A Ordinary Share Rights Offering (the "Offering") and related stand-by agreement in August 2008. Under the Offering, Caribbean Utilities raised US$28.2 million, the proceeds of which are supporting the ongoing capital programs necessary to meet energy demand and sustain reliability in the existing generation, transmission and distribution infrastructure.

Capital investments totalled approximately $44 million in 2008. A significant project included ongoing work to complete the 69-kV distribution line from Rum Point to Old Man Bay. Under a strategic alliance relationship, Caribbean Utilities has contracted MAN Diesel SE to manufacture, install and commission an additional 16 MW of capacity, scheduled for completion in September 2009, which will bring total installed MAN Diesel SE supplied generation to approximately 66 MW.

The Company continues to offer its Energy Smart Program to promote energy conservation and has been conducting complementary Energy Smart audits for customers for six years. Caribbean Utilities also participated in the Chamber of Commerce Business Expo, a three-day event that showcased local businesses and attracted more than 3,000 visitors.

The Company continues to demonstrate its environmental commitment through its ISO 14001:2004 registered Environmental Management System associated with its generation operations. Employee-development initiatives continue to demonstrate the ongoing commitment to the "Investors in People" certification that Caribbean Utilities achieved in 2006. The utility awarded a scholarship for the Masters Program in Renewable Energy Development at Heriot-Watt University in Scotland.

As part of its initiative to enhance specialized employee skills to meet future energy demand, Caribbean Utilities is focused on the ongoing apprenticeship training of employees who work in areas such as operations, mechanical and electrical. The Company implemented a management development program accredited by the Institute of Leadership and Management, one of the main organizations for supervisory training in the United Kingdom, for all supervisory staff.

Caribbean Utilities launched an electrical safety education program for schools on Grand Cayman. The program uses a model city to demonstrate electrical hazards associated with transmission and distribution systems as well as residential electricity use.

Left – Officers of Fortis Turks and Caicos (l-r): Ruth Gardiner-Forbes, VP, Finance and CFO; Ernest Jackson, VP, Generation and Engineering; Eddinton Powell, President and CEO; Brian Walsh, VP, Operations; Allan Robinson, VP, Customer and Corporate Services

Right – Fortis Turks and Caicos serves more than 9,000 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands.

Fortis Turks and Caicos

Regulated Electric Operations

Fortis Turks and Caicos serves more than 9,000 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands. The Company owns and operates a fully integrated system providing for the generation, transmission and distribution of electricity in Providenciales, North Caicos and Middle Caicos pursuant to a 50-year licence that expires in 2037. Fortis Turks and Caicos also owns and operates an independent generating station and transmission and distribution system on South Caicos and is the sole provider of electricity for that island pursuant to a 50-year licence that expires in 2036. In May, the Company began supplying electricity to Dellis Cay. Its regulated assets include 335 kilometres of transmission and distribution lines. The utility has a combined diesel-fired generating capacity of 48 MW and met a combined peak demand of 29 MW in 2008.

While challenged by increasing energy prices and severe weather conditions, the Company achieved a Customer Satisfaction Rating of 75 per cent in 2008.

In early September 2008, the Turks and Caicos Islands were struck by Tropical Storm Hanna followed by Hurricane Ike, a Category 4 hurricane which caused major damage to the utility's transmission and distribution system on South Caicos, with lesser damage occurring on North Caicos and Middle Caicos. Providenciales, the Company's major service territory and home to 80 per cent of its customers, was spared a direct hit. Generation facilities sustained minimal impact as a result of the hurricane. The Fortis Emergency Response Network, consisting of more than 60 employees throughout the Fortis Group of Companies, assisted Fortis Turks and Caicos with its restoration efforts. By the end of October, electricity had been restored to all customers ready to receive service.

Capital expenditures of approximately $44 million, before customer contributions, in 2008 primarily reflected investment in generation, transmission and distribution infrastructure, information technology platforms and systems, as well as land purchases necessary to meet energy demand and improve customer service.

The 2008/09 Generation Expansion Project is on schedule and will increase the Company's generating capacity by approximately 7 MW with the commissioning of two Caterpillar 3612 series units in early 2009. Capital projects undertaken to improve transmission and distribution reliability included the completion of dedicated underground feeders to Beaches Resort, the Islands' largest hotel, and the Provo Water Plant; the installation of a second power transformer at Grace Bay substation; and the completion of a transmission loop to Grace Bay substation. As a result of these initiatives, Fortis Turks and Caicos experienced a marked reduction in feeder outages in 2008.

New service connections included a number of large customers, among them Seven Stars Resort, Niki Beach Resort and Beach Club Resort.

The Company continued to implement recommendations from its environmental impact evaluation study. An environmental officer designate was appointed and received environmental training from Fortis Group personnel. Fortis Turks and Caicos plans to implement an environmental management system in 2009 that will be consistent with the international ISO 14001 standard by 2012.

Left – Construction of the US$53 million 19-MW Vaca hydroelectric generating facility on the Macal River in Belize is scheduled for completion at the beginning of 2010.
Right – Fortis Generation has a combined generating capacity of 195 MW, 190 MW of which is hydroelectric generation.

Fortis Generation

Non-Regulated Operations

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State with a combined generating capacity of 195 MW, 190 MW of which is hydroelectric generation.

In Belize, BECOL owns and operates the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities located on the Macal River. Mollejon and Chalillo are the largest commercial hydroelectric generating facilities in Belize. Energy production hit a record high of 192 GWh in 2008 due to above-average rainfall. The Belize Meteorological Office confirmed that the flood-control features of the Chalillo facility significantly reduced the impact on downstream communities of widespread flooding related to heavy rainfall in November. Construction of the US$53 million 19-MW Vaca hydroelectric generating facility continued and is scheduled for completion at the beginning of 2010. Vaca, a run-of-river plant situated approximately five kilometres downstream from Mollejon, is the final phase of the three-part hydroelectric development plan for the Macal River. BECOL sells its entire output to Belize Electricity under a 50-year PPA. Belize Electricity has signed a 50-year PPA with BECOL for the purchase of energy generated by Vaca. When it comes online, Vaca is expected to increase the average annual energy production from the Macal River by approximately 80 GWh to 240 GWh.

In Ontario, non-regulated operations include 75 MW of water-right entitlement associated with the Rankine hydroelectric generating station at Niagara Falls, which expires in April 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. With the exception of the cogeneration plant in Cornwall, the electricity produced from these facilities is sold in Ontario at market prices.

In central Newfoundland, Fortis Generation holds a 51 per cent interest in the Exploits River Hydro Partnership ("Exploits Partnership") with Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"). The Exploits Partnership was established in 2001 and commenced operations in 2003 following the development of additional capacity at Abitibi-Consolidated's two hydroelectric generating plants in central Newfoundland. The Exploits Partnership achieved annual production of 177 GWh in 2008. In December 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of Abitibi-Consolidated's assets in Newfoundland including those assets associated with the generation of electricity, some of which included the capital assets of the Exploits Partnership. The provincial government has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated in the province.

In British Columbia, the non-regulated generating asset is the 16-MW run-of-river Walden hydroelectric generating plant near Lillooet, which was acquired in May 2004 as part of the assets of FortisBC. The plant sells its entire output to BC Hydro under a long-term contract.

In Upper New York State, the non-regulated generating assets are four hydroelectric generating stations located in Moose River, Philadelphia, Dolgeville and Diana. The plants have a combined capacity of approximately 23 MW. The average annual 85 GWh of energy output from these modern facilities is sold at the wholesale level through a series of renewable contracts.

Left – Officers of Fortis Properties (l-r): Terry Chaffey, VP, Real Estate; Nora Duke, President and CEO; Jamie Roberts, VP, Finance and CFO

Right – In November 2008, Fortis Properties acquired Hotel Newfoundland. The 4½-star hotel, situated in historic downtown St. John's, features 301 guest rooms and approximately 16,000 square feet of premium meeting space, including 17 conference and special event rooms.

Fortis Properties

Non-Regulated Operations

Fortis Properties owns and operates 20 hotels, offering more than 3,800 rooms, in eight Canadian provinces and approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada. The Company, a wholly owned subsidiary of Fortis, is the primary vehicle for non-utility diversification and growth.

The Hospitality Division continued to demonstrate strong growth through property enhancement, expansion and acquisition. Revenue per available room increased for the 13th consecutive year, reaching $80.39, primarily due to a higher average daily room rate. In November 2008, Fortis Properties acquired Hotel Newfoundland for approximately $22 million. The 4½-star hotel, situated in historic downtown St. John's, features 301 guest rooms and approximately 16,000 square feet of premium meeting space, including 17 conference and special event rooms. Aligning with guest expectations for a high-quality service experience, this premier hotel was rebranded as Sheraton Hotel Newfoundland in early 2009. Over the next three years, an approximate $9 million capital investment will be made to upgrade the hotel.

A $14 million 70-room expansion of Holiday Inn Express Kelowna commenced in 2008, which includes the addition of an exclusive executive floor, business and family suites, more meeting space, an enhanced fitness facility and two indoor waterslides. A $0.7 million expansion of the Four Points by Sheraton Conference Centre in Halifax, Nova Scotia was completed during the year. The project utilized space in the Maritime Centre, enabling the hotel to attract larger groups and conventions while providing enhanced service for real estate tenants. The expanded facility includes 12,000 square feet of convention space, in-house audiovisual technology services and courtyard meeting space.

The Real Estate Division's stable performance is supported by long-term leases with quality tenants and strong tenant relations. The year-end occupancy rate was 96.8 per cent, outpacing the national rate of 93.3 per cent. Company buildings have virtually zero vacancy in a number of downtown markets, including St. John's and Halifax. Capital improvements to real estate assets included a $1.4 million investment at Brunswick Square for electrical equipment replacement and entrance renovations and upgrades.

Approximately $0.7 million was invested in technology solutions to improve productivity and provide optimal customer service. A new financial management system was installed and a multiphase project to install a new payroll system is ongoing.

The Hospitality Division continued to demonstrate quality customer service. The Delta St. John's Hotel and Conference Centre won *Hospitality Newfoundland and Labrador's Accommodation of the Year Award* for demonstrating dedication to quality service, commitment to the tourism industry and community contribution. For the 11th consecutive year, Holiday Inn Peterborough-Waterfront won the *Readers' Choice Award for Best Hotel in Peterborough* from the region's newspaper, *The Peterborough Examiner*.

Significant emphasis continued to be placed on ensuring compliance with health and safety regulations and raising awareness of health and safety practices. Safety audits were conducted at all properties in 2008.

Leadership development remains a priority as Fortis Properties continues to focus on the growth of high-potential employees through mentoring, professional development courses, special projects, temporary assignments, lateral moves and job promotion.

In 2008, almost $3 million in financial and in-kind donations was distributed to a wide selection of well-deserving community causes.

Our Community

Fortis remains focused on making a difference in the communities where our employees work and live. In 2008, almost $3 million in financial and in-kind donations was distributed to a wide selection of well-deserving community causes. Hundreds of employees throughout the Fortis Group of Companies were there to help.

Terasen sponsored the *2008 Environmental Mind Grind* organized by the Environmental Educators of the Central Okanagan Heroes. The event motivated 95 school teams and 450 students throughout British Columbia to display their environmental stewardship knowledge in a game show-style trivia contest.

FortisAlberta employees in Calgary, Red Deer and Edmonton raised $25,000 for the *CIBC Run for the Cure* in 2008. It was a record-setting year for participation by employees, who raised twice the amount collected in 2007.

FortisBC employees came together and raised almost $6,000 for the *Hour Kids Campaign*, a fundraiser to help complete upgrades to the maternity and pediatric departments at the Kootenay Boundary Regional Hospital.

Newfoundland Power employees were recognized with a national award at the 9th annual Canadian Blood Services *Honouring Our Lifeblood* event. Since joining the *Partners for Life* program in 2004, employees have made more than 1,400 blood donations.

Maritime Electric offered its *Electrical Safety Presentation* as part of the Grade Six science and math curriculum throughout the school system on Prince Edward Island.

FortisOntario donated $5,000 to the *Port Cares Reach Out Centre* in Port Colborne. The Centre offers a drop-in service and meal program, serving approximately 12,000 meals to the general public each year.

Belize Electricity awarded a three-year scholarship, valued at BZ$36,000 per annum, to a Belizean student to pursue a *Diploma in Engineering Technology* at the College of the North Atlantic in Newfoundland.

Caribbean Utilities enhanced its partnership with the *Central Caribbean Marine Institute*, an international non-profit organization that is extending its Coral Reef Awareness Program to schools across Grand Cayman through its Ocean Literacy education curriculum.

Fortis Turks and Caicos joined the campaign to redevelop the sport of cricket on the Turks and Caicos Islands by making a $4,000 donation and becoming the title sponsor of the *Provo Cricket Association's Men's League*.

Fortis Properties was the title sponsor of the *Business Community Anti-Poverty Initiative Annual Golf Tournament* in New Brunswick. Through its participation during the past six years, the Company has assisted in raising more than $240,000 in support of the Resource Centre for Youth in Saint John.

Management Discussion and Analysis

Barry Perry, VP, Finance and CFO, Fortis Inc.

Dated March 11, 2009

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the 2008 Consolidated Financial Statements and Notes to the 2008 Consolidated Financial Statements included in the Fortis Inc. ("Fortis" or the "Corporation") 2008 Annual Report. The MD&A has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. Financial information in the MD&A has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected timing of regulatory decisions; the electricity sales growth rate expected at the Corporation's regulated utilities in the Caribbean in 2009; consolidated forecasted gross capital expenditures for 2009 and in total over the next five years, as well as the expected significant capital projects in 2009 and their expected costs and time to complete; the expected impacts on Fortis of the downturn in the global economy; the expected increase in activities at Terasen Energy Services; no significant decrease in subsidiary operating cash flows is expected in 2009; the subsidiaries expect to be able to source the cash required to fund their 2009 capital expenditure programs; the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2009; expected long-term debt maturities and repayments in 2009 and on average annually over the next five years; no material increase in interest expense and/or fees associated with renewed and extended credit facilities is expected in 2009; no material adverse credit rating actions are expected in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2009; the estimated impact a decease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; the expectation that counterparties to the Terasen Gas companies' gas derivative contracts will continue to meet their obligations; and the expectation of no material increase in defined benefit pension expense in 2009. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major event; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no significant decline in capital spending in 2009; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices; no significant variability in interest rates; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas supply; the continued ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no material decrease in market energy sales prices; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; operating and maintenance risks; economic conditions; capital resources and liquidity risk; weather and seasonality; an ultimate resolution of the Exploits River Hydro Partnership that differs from what is currently expected by management; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk;

competitiveness of natural gas; natural gas supply; defined benefit pension plan performance and funding requirements; risks related to the development of the Terasen Gas (Vancouver Island) Inc. franchise; the Government of British Columbia's Energy Plan; environmental risks; insurance coverage risk; an unexpected outcome of legal proceedings currently against the Corporation; licences and permits; loss of service area; market energy sales prices; transition to International Financial Reporting Standards; changes in tax legislation; First Nations' lands; labour relations and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in this MD&A for the year ended December 31, 2008.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

Corporate Overview and Strategy

Fortis is the largest investor-owned distribution utility in Canada serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State and hotels and commercial real estate in Canada. In 2008, the Corporation's electricity distribution systems met a combined peak electricity demand of more than 5,700 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,402 terajoules ("TJ").

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's first priority is to pursue organic growth opportunities in existing operations. Additionally, Fortis pursues profitable growth through acquisitions.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, deliver gas and electricity safely and reliably to customers at reasonable rates, and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated. It is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. The operating segments of the Corporation are: (i) Regulated Gas Utilities – Canadian; (ii) Regulated Electric Utilities – Canadian; (iii) Regulated Electric Utilities – Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated – Fortis Properties; and (vi) Corporate and Other. The earnings of the Corporation's regulated utilities are primarily determined under traditional cost of service and rate of return methodologies. Earnings of the Canadian regulated utilities are generally exposed to changes in interest rates which factor into customer rate-setting mechanisms.

Fortis holds investments in non-regulated generation, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's non-regulated generation assets operate in three countries and have a combined generating capacity of 195 MW, mainly hydroelectric. Except for non-regulated hydroelectric generation operations in Belize and British Columbia, the Corporation's non-regulated generation operations are owned and/or managed by Fortis Properties to ensure standard operating practices, enable leveraging of expertise across the various jurisdictions and allow the pursuit of non-regulated hydroelectric projects. The Corporation's investments in non-regulated assets provide for financial, tax and regulatory flexibility and enhance shareholder return.

The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving approximately 834,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving approximately 95,000 residential, commercial and industrial customers.

In addition to providing transmission and distribution ("T&D") services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the propane distribution system in Whistler, British Columbia, providing service to approximately 2,400 residential and commercial customers.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 461,000 customers.

b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving more than 157,000 customers. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 MW. Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 269-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power:* Newfoundland Power is the principal distributor of electricity in Newfoundland, serving approximately 236,000 customers. Newfoundland Power has an installed generating capacity of approximately 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Includes Maritime Electric and FortisOntario. Maritime Electric is the principal distributor of electricity on Prince Edward Island, serving approximately 73,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario's operations primarily include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012.

Regulated Electric Utilities – Caribbean

a. *Belize Electricity:* Belize Electricity is the principal distributor of electricity in Belize, Central America, serving approximately 74,000 customers. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

b. *Caribbean Utilities:* Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 24,000 customers. The Company has an installed generating capacity of approximately 137 MW. Fortis has an approximate 57 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Going forward, this change in the Company's fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' financial results.

c. *Fortis Turks and Caicos:* Includes P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands, serving more than 9,000 customers. The Company has a combined diesel-fired generating capacity of 48 MW.

Non-Regulated – Fortis Generation

The following summary describes the Corporation's non-regulated generation assets by location:

a. *Belize:* Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. The hydroelectric generation operations in Belize are conducted through the Corporation's indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.

b. *Ontario:* Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires April 30, 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary, Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Fortis Properties holds directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro") under a 30-year power purchase agreement expiring in 2033. For a further discussion of the Exploits Partnership and pending changes related to it refer to the "Liquidity and Capital Resources – Cash Flow Requirements" and "Critical Accounting Estimates – Contingencies" sections of this MD&A.

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013.

e. *Upper New York State:* Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, operating under licences from the US Federal Energy Regulatory Commission. Hydroelectric operations in Upper New York State are conducted through the Corporation's indirect wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 20 hotels comprised of more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment. This segment includes finance charges, including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen Inc. corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. While currently not significant, financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

Financial Highlights

For the Years Ended December 31	2008	2007	Variance *(%)*
Net Earnings Applicable to Common Shares *($ millions)*	**245**	193	26.9
Basic Earnings per Common Share *($)*	**1.56**	1.40	11.4
Diluted Earnings per Common Share *($)*	**1.52**	1.32	15.2
Weighted Average Number of Common Shares Outstanding *(millions)*	**157.4**	137.6	14.4
Revenue *($ millions)*	**3,903**	2,718	43.6
Dividends Paid per Common Share *($)*	**1.00**	0.82	22.0
Return on Average Common Shareholders' Equity *(%)*	**8.7**	10.0	(13.0)
Total Assets *($ millions)*	**11,178**	10,273	8.8
Cash Flow From Operating Activities *($ millions)*	**663**	373	77.7

Acquisitions: In November 2008, Fortis Properties acquired the Fairmont Newfoundland hotel for approximately $22 million, increasing hospitality operations by 301 rooms and 16,000 square feet of convention space.

On May 17, 2007, Fortis completed the acquisition of all of the issued and outstanding common shares of Terasen, formerly a wholly owned subsidiary of Kinder Morgan, Inc., for aggregate consideration of $3.7 billion, including the assumption of approximately $2.4 billion of consolidated debt. Terasen owns and operates a gas distribution business carried on by TGI, TGVI and TGWI. The acquisition did not include the petroleum transportation assets of Kinder Morgan Canada (formerly Terasen Pipelines), which are comprised primarily of refined and crude oil pipelines.

A significant portion of the net cash purchase price of Terasen was satisfied with the net proceeds of the public offering of Subscription Receipts completed by Fortis on March 15, 2007. Fortis issued approximately 44.3 million Subscription Receipts for gross proceeds of approximately $1.15 billion. Upon closing of the acquisition on May 17, 2007, each Subscription Receipt was automatically exchanged, without payment of additional consideration, for one common share of Fortis. The remaining net cash purchase price was financed, on an interim basis, by drawing $125 million on the Corporation's existing credit facility.

On August 1, 2007, Fortis Properties purchased the Delta Regina, comprised of the 274-room Delta Regina hotel, the Saskatchewan Trade and Convention Centre, 52,000 square feet of commercial office space and a parking garage in Regina, Saskatchewan, for an aggregate cash purchase price of approximately $50 million.

Key Trends and Risks: Terasen improved the risk profile of Fortis by providing the Corporation with a more economically diverse portfolio of assets and earnings. The expansion into natural gas added a new business segment, doubled the regulated rate base of Fortis and was complementary to the Corporation's proven core competencies in managing regulated electric distribution utilities. The distribution franchises of the Terasen Gas companies have a well-diversified, mature, principally residential customer base and operate in a service territory that has experienced steady economic growth and includes substantially all of the service territory of FortisBC. The expansion into natural gas distribution provides Fortis with a platform for future growth in the regulated natural gas business in Canada and the United States.

A large proportion of the businesses of Fortis serve the economies of western Canada, which have been growing faster than other regions of Canada. As at December 31, 2008, regulated utility assets comprised 92 per cent of total assets (December 31, 2007 – 92 per cent) and regulated utility assets in Canada comprised 82 per cent of total assets (December 31, 2007 – 84 per cent).

Declining long-term interest rates in Canada since 2005 have negatively impacted the formula-based allowed rate of return on common shareholders' equity ("ROE") used to set customer rates at each of the Corporation's four largest regulated utilities. The chart below highlights the trend in the regulator-allowed ROEs at each of the Corporation's four largest regulated utilities.

Regulator-Allowed ROE

(%)	2005	2006	2007	2008	2009
Terasen Gas Inc.	9.03	8.80	8.37	8.62	8.47
FortisAlberta	9.50	8.93	8.51	8.75	8.51[(1)]
FortisBC	9.43	9.20	8.77	9.02	8.87
Newfoundland Power	9.24	9.24	8.60	8.95	8.95

[(1)] Interim ROE pending outcome of regulatory proceeding

The impact on the Corporation's consolidated earnings of lower allowed ROEs has been more than offset by earnings derived from increased rate bases and energy sales and the realization of operating cost efficiencies.

Economic growth in the province of Alberta has been robust in the past few years translating into strong customer, energy sales and rate base growth at FortisAlberta. The rate of growth may decrease in 2009 due to the current global economic environment and depressed world oil prices. FortisAlberta's service territory includes the environs of Calgary and Edmonton as well as the corridor between these cities. A healthy British Columbia provincial economy and population growth in the Okanagan region have favourably impacted customer and sales growth at FortisBC and the Terasen Gas companies over the past few years. Sales growth in 2008 at FortisBC was tempered due to decreased activity in the forestry sector. Organic earnings growth from the Corporation's regulated utilities in Canada is expected to be primarily driven by rate base growth at FortisAlberta, FortisBC and the Terasen Gas companies. The Corporation's other Canadian regulated electric utilities, Newfoundland Power, Maritime Electric and FortisOntario, are expected to generate slower earnings' growth.

Regulated assets in the Caribbean region, as a percentage of the Corporation's total regulated assets, were 10 per cent at December 31, 2008 (December 31, 2007 – 8 per cent). The regulated rate of return on rate base assets ("ROA") achieved in the Caribbean is higher than that achieved in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors and weather conditions. However, the allowed ROAs at Caribbean Utilities and Belize Electricity were lowered in 2008 due to the negotiation of new licences at Caribbean Utilities and the impact of a regulatory rate decision at Belize Electricity. Economic growth has been strong in the Corporation's service territories in the Caribbean, positively impacting customer and sales growth. The rate of growth is expected to be lower in 2009 due to the impact of the global economic downturn. The Corporation's operations in the Caribbean are exposed to hurricane risk. Fortis uses external insurance to help mitigate the impact on its operations of potential damage and related business interruption associated with hurricanes.

The key business risk to Fortis is regulatory risk. Except for the Terasen Gas companies and FortisBC, which have the same regulator, the Corporation's other utilities are regulated by different regulatory authorities. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been positive. However, the relationship of Belize Electricity with its regulator became tenuous in 2008 when the regulator issued a decision disallowing previously incurred fuel and purchased power costs and lowering the regulated ROA. The decision has negatively impacted Belize Electricity's financial health. Although the receipt of an adverse regulatory decision may materially affect the ability of any utility to recover the cost of providing its services and achieving a reasonable rate of return, the impact on the Corporation as a whole is lessened due to the geographic and regulatory diversity of its operations. The total assets of Belize Electricity comprise approximately 2 per cent of the Corporation's total assets.

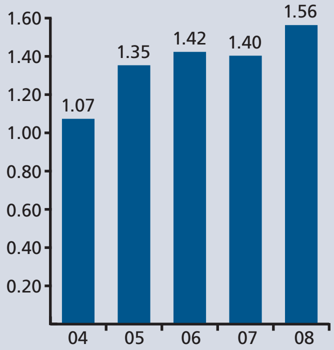
In Canada, regulator-approved negotiated settlement agreements were reached at FortisAlberta and FortisBC for 2008 and 2009 electricity rates and at Newfoundland Power for 2008 electricity rates. Achieving regulator-approved negotiated settlement agreements eliminates the cost of full-scale public hearing processes. Customer rates at Newfoundland Power and the Terasen Gas companies have also been set for 2009.

The Corporation's regulated gas and electric utilities require continual access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the subsidiary capital expenditure programs is mostly obtained at the regulated utility level. The subsidiaries issue debt mostly at terms ranging between 10 years and 30 years. As at December 31, 2008, approximately 84 per cent of the Corporation's consolidated long-term debt and capital lease obligations had maturities beyond five years. To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have $2.2 billion in credit facilities of which approximately $1.5 billion was available as at December 31, 2008. During 2008, Fortis and its subsidiaries issued almost $1.2 billion in equity and long-term debt. With strong credit ratings and conservative capital structures, the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2009.

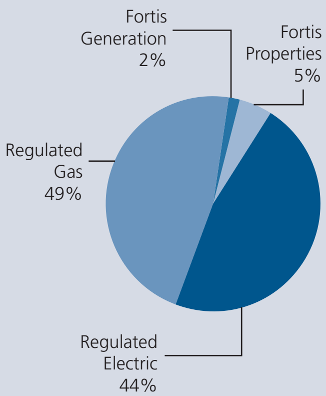
Common share dividend payments increased to $1.00 per common share in 2008. Effective for the first quarter of 2009, a 4 per cent increase in the quarterly common share dividend to 26 cents from 25 cents extends the Corporation's record of annual common share dividend increases to 36 consecutive years, the longest record of any public corporation in Canada.

For a complete discussion of the Corporation's business risks, including regulatory risk and the impact on the Corporation and its subsidiaries of recent economic conditions, refer to the "Regulatory Highlights", "Business Risk Management" and "Outlook" sections of this MD&A.

Basic Earnings per Common Share *($)*

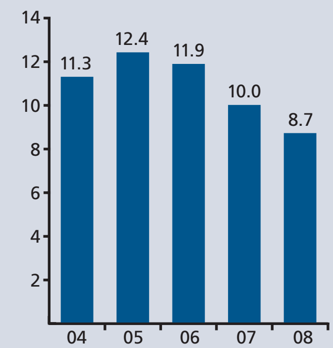


Revenue[(1)]
(year ended December 31, 2008)



[(1)] Excludes Corporate and Other

Return on Average Common Shareholders' Equity *(%)*



Net Earnings Applicable to Common Shares and Earnings per Common Share: Fortis achieved net earnings applicable to common shares of $245 million in 2008, a 26.9 per cent increase over earnings of $193 million in the previous year. The increase in earnings was primarily due to earnings' contributions from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007, rate base growth and higher allowed ROEs at the Corporation's Canadian regulated utilities, and increased non-regulated hydroelectric production due to higher rainfall. The increase was tempered by a one-time $13 million loss related to a June 2008 regulatory rate decision at Belize Electricity and lower corporate tax recoveries at FortisAlberta. Results for 2008 also reflected a $7.5 million tax reduction ($5.5 million at the Terasen Gas companies and $2 million at Terasen Inc.) associated with the settlement of historical corporate tax matters at Terasen. Results for 2007 reflected a $7 million after-tax gain on the sale of surplus land at TGI.

Basic earnings per common share were $1.56 in 2008, an 11.4 per cent increase over $1.40 in the previous year. The increase was primarily due to growth in earnings associated with the Terasen Gas companies and increased non-regulated hydroelectric production. Basic earnings per common share in 2007 were diluted by the common shares issued to fund the acquisition of Terasen and by the seasonality of earnings at the Terasen Gas companies.

Revenue: Revenue increased 43.6 per cent to approximately $3.9 billion from approximately $2.7 billion in 2007. The increase was driven by contributions from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007. The remainder of the increase was mainly the result of customer rate increases, which included the impact of higher allowed ROEs for 2008 and the flow through to customers of higher energy supply costs; two additional months of contribution from Caribbean Utilities due to a change in the utility's fiscal year end; and customer growth.

Return on Average Common Shareholders' Equity: Return on average common shareholders' equity was 8.7 per cent in 2008 compared to 10.0 per cent in 2007. The decline largely related to higher average common shareholders' equity associated with the May 2007 acquisition of Terasen.

Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was $663 million in 2008, 77.7 per cent higher than $373 million in the previous year. The increase primarily reflected a full year of contributions from the Terasen Gas companies in 2008.

2008 Capital Expenditures: During 2008, consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were $904 million, including capital expenditures of approximately $220 million at the Terasen Gas companies. Total capital investment at FortisAlberta and FortisBC during 2008 was approximately $419 million, representing approximately 46 per cent of total gross capital expenditures. Much of the capital investment was driven by customer growth and the need to enhance the reliability of electricity systems.

Management Discussion and Analysis

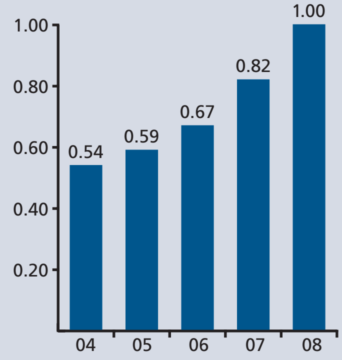
Dividends: Dividends paid per common share increased to $1.00 in 2008, up 22.0 per cent from 82 cents in 2007. Commencing with the first quarter dividend paid on March 1, 2009, Fortis increased its quarterly common share dividend 4 per cent to 26 cents from 25 cents. The Corporation's dividend payout ratio was 64.1 per cent in 2008 compared to 58.6 per cent in 2007.

In December 2008, the Corporation amended and restated its Dividend Reinvestment and Share Purchase Plan to provide a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009.

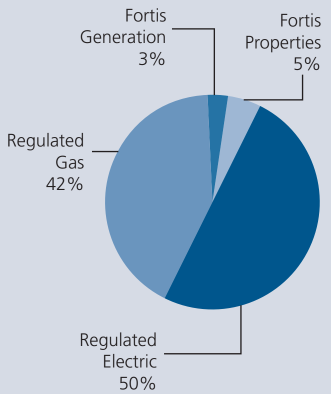
Asset Growth: Total assets increased 8.8 per cent to approximately $11.2 billion at the end of 2008 compared to approximately $10.3 billion at the end of 2007. The increase was primarily due to the Corporation's continued investment in energy systems at FortisAlberta, FortisBC and the Terasen Gas companies, combined with the impact of foreign exchange associated with translation of foreign currency-denominated assets.

Financings: During 2008, Fortis and its utilities raised almost $1.2 billion of capital from a combination of preference share, common share and long-term debt issues. In the second quarter of 2008, the Corporation publicly issued 9.2 million 5.25% Five-Year Fixed-Rate Reset First Preference Shares, Series G ("First Preference Shares, Series G") for gross proceeds of approximately $230 million ($223 million net of costs). The net proceeds were used to repay $170 million under the Corporation's committed credit facility, fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes. In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately $300 million ($287 million net of costs). The net proceeds were used to repay short-term debt primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008 and for general corporate purposes. At the subsidiary level, TGVI issued $250 million of 30-year 6.05% unsecured debentures in February; FortisAlberta issued $100 million of 30-year 5.85% unsecured debentures in April; Maritime Electric issued $60 million of 30-year 6.05% secured first mortgage bonds in April; and TGI issued $250 million of 30-year 5.80% unsecured debentures in May. Proceeds from the long-term debt issues at the utilities were primarily used to repay indebtedness under credit facilities incurred in support of capital spending. Additionally, partial proceeds from the issuance of the $250 million unsecured debentures by TGI were used to refinance $188 million of debt that matured in May 2008.

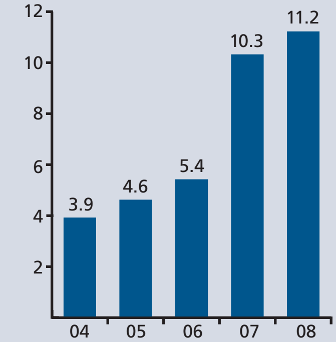
Dividends Paid per Common Share *($)*



Total Assets
(as at December 31, 2008)



Total Assets *($ billions)*
(as at December 31)



Segmented Results of Operations

The segmented results of the Corporation are outlined below.

Segmented Net Earnings

Years Ended December 31 *($ millions)*	**2008**	2007	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies [1]	**118**	50	68
Regulated Electric Utilities – Canadian			
FortisAlberta	**46**	48	(2)
FortisBC	**34**	31	3
Newfoundland Power	**32**	30	2
Other Canadian	**14**	16	(2)
	126	125	1
Regulated Electric Utilities – Caribbean [2]	**17**	31	(14)
Non-Regulated – Fortis Generation	**30**	24	6
Non-Regulated – Fortis Properties [3]	**23**	24	(1)
Corporate and Other	**(69)**	(61)	(8)
Net Earnings Applicable to Common Shares	**245**	193	52

(1) Financial results are reported from May 17, 2007, the date of acquisition.

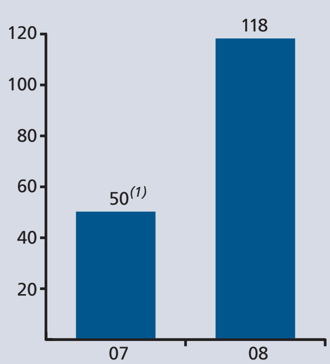
(2) Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Going forward, this change in fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' financial results.

(3) Includes the results of the Fairmont Newfoundland hotel from November 2008, the date of acquisition

REGULATED UTILITIES

The Corporation's primary business is regulated utilities. In 2008, regulated earnings in Canada and the Caribbean represented approximately 83 per cent (2007 – 81 per cent) of the Corporation's earnings from its operating segments (excluding the Corporate and Other segment). Total regulated assets represented 92 per cent of the Corporation's total assets as at December 31, 2008 (December 31, 2007 – 92 per cent).

Regulated Gas Utilities – Canadian Earnings *($ millions)*



(1) Earnings are from May 17, 2007

Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2008 were $118 million (2007 – $50 million), which represented approximately 45 per cent of the Corporation's total regulated earnings (2007 – 24 per cent). Earnings for 2007 were from May 17, 2007, the date of acquisition of the Regulated Gas Utilities – Canadian. Regulated Gas Utilities – Canadian assets were approximately $4.6 billion as at December 31, 2008 (December 31, 2007 – $4.4 billion), which represented approximately 45 per cent of the Corporation's total regulated assets as at December 31, 2008 (December 31, 2007 – 47 per cent).

Terasen Gas Companies

Financial Highlights

Years Ended December 31	**2008**	2007 [1]	Variance
Gas Volumes *(TJ)*	**221,122**	118,309	102,813
($ millions)			
Revenue	**1,902**	905	997
Energy Supply Costs	**1,268**	559	709
Operating Expenses	**253**	150	103
Amortization	**97**	58	39
Finance Charges	**129**	80	49
Gain on Sale of Property	**–**	(8)	8
Corporate Taxes	**37**	16	21
Earnings	**118**	50	68

(1) Results are reported from May 17, 2007, the date of acquisition.

Gas Volumes: Gas volumes were 221,122 TJ for 2008 compared to 220,977 TJ reported by the Terasen Gas companies for the full year in 2007. Increased sales volumes to residential customers, as a result of increased consumption due to cooler weather year over year, and higher sales volumes to customers under fixed price contracts, were largely offset by lower transportation volumes to customers sourcing their own gas supplies.

The Terasen Gas companies earn approximately the same margin regardless of whether a customer contracts for the purchase of natural gas or contracts for the transportation of natural gas only.

As a result of the operation of British Columbia Utilities Commission ("BCUC")-approved regulatory deferral mechanisms, changes in consumption levels and energy supply costs from those forecasted to set gas distribution rates do not materially affect earnings.

During 2008, net customer additions at TGI and TGVI totalled approximately 12,800, bringing the total customer count at TGI and TGVI to approximately 929,000 at December 31, 2008. During 2007, net customer additions at TGI and TGVI totalled approximately 13,900. Net customer additions in 2008 were lower than expected, reflecting weakening housing and construction markets and growth in multi-family housing where natural gas use is less prevalent compared to single-family housing.

Revenue: Revenue was approximately $1.9 billion for 2008 compared to $905 million for the partial year in 2007. In addition to the impact of revenue contribution for the full year in 2008, revenue also increased year over year due to: (i) the higher commodity cost of gas charged to customers; (ii) increased residential customer consumption; and (iii) an increase in gas distribution rates, effective January 1, 2008, which included the impact of an increase in the 2008 allowed ROE for TGI and TGVI to 8.62 per cent and 9.32 per cent, respectively, from 8.37 per cent and 9.07 per cent, respectively.

Earnings: Earnings were $118 million for 2008 compared to $50 million for the partial year in 2007. Earnings for 2007 were favourably impacted by a $7 million after-tax gain on the sale of surplus land. Earnings for 2008 included an approximate $5.5 million tax reduction associated with the settlement of historical corporate tax matters. During the third quarter of 2008, Terasen reached a settlement with Revenu Québec and Canada Revenue Agency ("CRA") related to amounts owing as a result of amended Québec tax legislation. The legislation was passed in 2006 for the purpose of challenging certain interprovincial Canadian tax structures.

In addition to earnings' contribution for a full year in 2008 and the one-time tax reduction described above, earnings for 2008 were favourably impacted by the increase in gas distribution rates, effective January 1, 2008, reflecting a higher allowed ROE, partially offset by: (i) higher operating expenses driven by increased labour costs; (ii) higher amortization costs associated with the continued investment in capital assets; and (iii) higher finance charges reflective of higher borrowing rates.

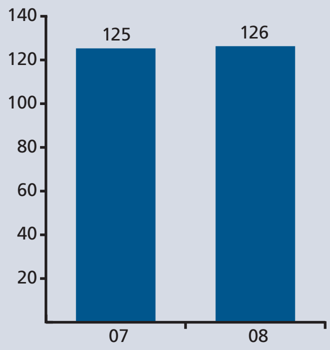
Seasonality materially impacts the earnings of the Terasen Gas companies as a major portion of the gas distributed is used for space heating. Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Outlook: TGI's allowed ROE for 2009 has been set at 8.47 per cent, down from 8.62 per cent in 2008. TGVI's allowed ROE for 2009 has been set at 9.17 per cent, down from 9.32 per cent in 2008. TGI and TGVI are currently preparing rate applications related to 2010 which are anticipated to be filed with the regulator in the second quarter of 2009.

In February 2009, TGI issued $100 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay $60 million of unsecured debentures that mature in June 2009.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Terasen Gas companies is provided under the heading "Regulatory Highlights". A summary of the forecast gross capital expenditures for 2009 for the Terasen Gas companies is provided under the heading "Liquidity and Capital Resources – Capital Program".

Regulated Electric Utilities – Canadian Earnings *($ millions)*



Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2008 were $126 million (2007 – $125 million), which represented approximately 48 per cent of the Corporation's total regulated earnings (2007 – 61 per cent). Regulated Electric Utilities – Canadian assets were approximately $4.6 billion as at December 31, 2008 (December 31, 2007 – $4.2 billion), which represented approximately 45 per cent of the Corporation's total regulated assets as at December 31, 2008 (December 31, 2007 – 45 per cent).

FortisAlberta

Financial Highlights

Years Ended December 31	2008	2007	Variance
Energy Deliveries *(GWh)*	**15,722**	15,378	344
($ millions)			
Revenue	**300**	270	30
Operating Expenses	**130**	122	8
Amortization	**85**	75	10
Finance Charges	**42**	36	6
Corporate Tax Recovery	**(3)**	(11)	8
Earnings	**46**	48	(2)

Energy Deliveries: Energy deliveries at FortisAlberta increased 344 gigawatt hours ("GWh"), or 2.2 per cent, year over year, mainly due to customer growth. During 2008, the number of customers at FortisAlberta increased by approximately 12,700, bringing the total number of customers at FortisAlberta to approximately 461,000 at the end of 2008.

As a significant portion of the Company's distribution revenue is derived from fixed or largely fixed billing determinants, changes in energy deliveries are not directly correlated with changes in revenue.

Revenue: Revenue was $30 million higher than the previous year, mainly due to: (i) a 6.8 per cent increase in customer distribution rates, effective January 1, 2008; (ii) the impact of customer and load growth; (iii) the accrual for collection in future customer distribution rates of the increase in the 2008 allowed ROE to 8.75 per cent from 8.51 per cent, effective January 1, 2008; and (iv) increased franchise fee revenue.

Earnings: Earnings were $2 million lower than the previous year, driven by lower future income tax recoveries primarily associated with the regulator-approved Alberta Electric System Operator ("AESO") charges deferral account. Additionally, higher revenue was partially offset by: (i) higher operating expenses due to increased contracted manpower costs, higher labour and employee-benefit costs associated with increased salaries and number of employees, and higher general operating expenses; (ii) increased amortization costs associated with continued investment in capital assets and higher amortization rates provided for in the 2008/2009 Negotiated Settlement Agreement ("NSA"); and (iii) increased finance charges driven by higher debt levels in support of the Company's significant capital expenditure program.

FortisAlberta's AESO charges deferral account captures variances between amounts charged by the AESO to FortisAlberta for transmission tariffs and amounts collected by FortisAlberta from customers through the transmission tariff component of basic customer rates. Subject to regulatory approval, amounts charged by the AESO in excess of amounts collected from customers are deferred as a regulatory asset for future recovery from customers, and amounts collected from customers in excess of amounts charged are deferred as a regulatory liability for future refund to customers. Generally, there is a two-year lag between the deferral of amounts in the AESO charges deferral account and their collection from, or refund to, customers in rates.

FortisAlberta records income taxes on the cash taxes payable method, as approved by its regulator, except for certain deferral accounts, including the AESO charges deferral account, whereby income taxes are recorded using the liability method. During the third quarter of 2008, FortisAlberta identified that taxable income from operations, before considering impacts associated with the AESO charges deferral account, could be fully offset by utilizing capital cost allowance deductions. Then, by applying the tax deductions related to transmission tariff payments made to the AESO, a tax loss carryforward could be created and a future income tax recovery could be recorded. Under the liability method of recording income taxes, a future income tax asset associated with the tax loss carryforward may be recorded when there is certainty of recovery. The transmission tariff payments made to the AESO are recoverable from customers in the future; therefore, a future income tax asset and future income tax recovery were recorded in each of the third and fourth quarters of 2008, which offset the future income tax liability and future income tax expense created by the AESO charges deferral as it was incurred.

Prior to the third quarter of 2008, FortisAlberta was not deducting transmission tariff payments made to the AESO to create tax loss carryforwards and was not recording the associated future income tax recoveries. This accounting treatment, in effect, resulted in a two-year lag of recording the future income tax impacts between the payments of transmission tariff amounts to the AESO and the timing of their collection from customers. Going forward, fluctuations in corporate income taxes associated with the operation of the AESO charges deferral account are not expected to occur.

During 2007, net future income tax recoveries of approximately $9 million were recorded, primarily due to the sale of amounts deferred to the AESO charges deferral account. In September 2007, the 2006 deferred AESO charges receivable balance of $28 million and, in December 2007, approximately $38 million of the 2007 deferred AESO charges receivable balance, were sold to a Canadian chartered bank and, as a result, the proceeds were recognized in 2007.

Outlook: During 2008, the Alberta Utilities Commission ("AUC") ruled that a 2009 Generic Cost of Capital Proceeding to review ROE levels, adjustment mechanisms and utility capital structures would be appropriate for all gas, electric and pipeline utilities in Alberta that it regulates. As directed by the AUC, FortisAlberta is to continue using the 2007 allowed ROE of 8.51 per cent for 2009, down from the allowed ROE of 8.75 per cent in 2008, pending the outcome of the AUC's 2009 Generic Cost of Capital Proceeding.

FortisAlberta expects to file a 2010 and 2011 revenue requirements application during the second quarter of 2009.

In December 2008, FortisAlberta filed a short-form base shelf prospectus for the issuance of up to $350 million in debentures. In February 2009, FortisAlberta issued $100 million of 30-year 7.06% unsecured debentures under the shelf prospectus. The net proceeds were used to repay committed credit-facility borrowings incurred in support of the Company's capital expenditure program and for general corporate purposes.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisAlberta is provided under the heading "Regulatory Highlights". A summary of the forecast gross capital expenditures for 2009 for FortisAlberta is provided under the heading "Liquidity and Capital Resources – Capital Program".

FortisBC

Financial Highlights

Years Ended December 31	2008	2007	Variance
Electricity Sales *(GWh)*	**3,087**	3,091	(4)
($ millions)			
Revenue	**237**	229	8
Energy Supply Costs	**68**	67	1
Operating Expenses	**67**	69	(2)
Amortization	**34**	31	3
Finance Charges	**28**	26	2
Corporate Taxes	**6**	5	1
Earnings	**34**	31	3

Electricity Sales: Electricity sales at FortisBC decreased 4 GWh, or 0.1 per cent, year over year due to reduced industrial customer loads as a result of a general slowdown in the forestry sector, partially offset by the impact of residential, general service and wholesale customer growth.

Revenue: Revenue was $8 million higher than the previous year, driven by the impact of: (i) a 2.9 per cent increase in electricity rates, effective January 1, 2008, which included the impact of an increase in the 2008 allowed ROE to 9.02 per cent from 8.77 per cent; (ii) a 0.8 per cent increase in electricity rates, effective May 1, 2008, as a result of the flow through to customers of increased purchased power costs from BC Hydro; and (iii) a shift in sales mix from lower-rate to higher-rate customer classes. The increase was partially offset by lower revenue contributions from non-regulated operating, maintenance and management services and lower electricity sales.

Earnings: Earnings were $3 million higher than the previous year. The increase was primarily due to the 2.9 per cent increase in electricity rates, partially offset by higher amortization costs and finance charges related to the Company's significant capital expenditure program.

Operating expenses were $2 million lower than the previous year, mainly due to lower operating expenses associated with non-regulated operating, maintenance and management services, partially offset by the impact of higher labour costs and general inflationary cost increases year over year.

Outlook: FortisBC's allowed ROE for 2009 has been set at 8.87 per cent, down from 9.02 per cent in 2008. In December 2008, FortisBC received regulatory approval of the Company's 2009 Revenue Requirements Application, resulting in a general rate increase of 4.6 per cent, effective January 1, 2009. The approval of the 2009 Revenue Requirements Application also included an extension of the performance-based rate-setting ("PBR") mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisBC is provided under the heading "Regulatory Highlights". A summary of the forecast gross capital expenditures for 2009 for FortisBC is provided under the heading "Liquidity and Capital Resources – Capital Program".

Newfoundland Power

Financial Highlights

Years Ended December 31	2008	2007	Variance
Electricity Sales *(GWh)*	**5,208**	5,093	115
($ millions)			
Revenue	**517**	491	26
Energy Supply Costs	**337**	327	10
Operating Expenses	**50**	53	(3)
Amortization	**45**	34	11
Finance Charges	**33**	34	(1)
Corporate Taxes	**19**	12	7
Non-Controlling Interest	**1**	1	–
Earnings	**32**	30	2

Electricity Sales: Electricity sales at Newfoundland Power increased 115 GWh, or 2.3 per cent, year over year, primarily due to the combined impact of customer growth and higher average consumption.

Revenue: Revenue in 2008 was $26 million higher than the previous year. The increase was driven by an average increase in customer rates of 2.8 per cent, effective January 1, 2008, which included the impact of an increase in the 2008 allowed ROE to 8.95 per cent from 8.60 per cent, and electricity sales growth. The increase in revenue also reflected higher amortization of regulatory liabilities in accordance with prescribed regulatory orders.

Earnings: Earnings were $2 million higher than the previous year, driven by the average 2.8 per cent increase in customer rates, effective January 1, 2008, lower operating expenses driven by the timing of expenses and lower maintenance and pension costs, and lower finance charges. Finance charges decreased due to the refinancing of maturing debt in August 2007 at lower rates.

Amortization costs were higher year over year due to the regulator-approved recovery in customer rates, effective January 1, 2008, of previously deferred amortization costs.

Corporate tax expense increased year over year as a result of higher earnings before corporate taxes, combined with a higher effective corporate income tax rate, which was driven by decreased deductions taken for tax purposes compared to accounting purposes.

Outlook: Newfoundland Power's allowed ROE for 2009 has been set at 8.95 per cent, unchanged from 2008; consequently, there has been no change in base customer rates for 2009.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Newfoundland Power is provided under the heading "Regulatory Highlights". A summary of Newfoundland Power's forecast gross capital expenditures for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Other Canadian Electric Utilities[1]

Financial Highlights

Years Ended December 31	2008	2007	Variance
Electricity Sales *(GWh)*	**2,182**	2,209	(27)
($ millions)			
Revenue	**262**	263	(1)
Energy Supply Costs	**177**	174	3
Operating Expenses	**28**	29	(1)
Amortization	**18**	17	1
Finance Charges	**18**	17	1
Corporate Taxes	**7**	10	(3)
Earnings	**14**	16	(2)

(1) Includes Maritime Electric and FortisOntario

Electricity Sales: Electricity sales at Other Canadian Electric Utilities decreased 27 GWh, or 1.2 per cent, year over year. The decrease was driven by the impact of the shut down of operations of certain industrial customers in Ontario and lower average consumption in Ontario.

Revenue: Revenue was $1 million lower than the previous year. During 2007, FortisOntario received a one-time refund of approximately $3 million ($2 million after-tax) from Niagara Mohawk Power Corporation ("NIMO") associated with cross-border transmission interconnection agreements. In April 2008, the US Federal Energy Regulatory Commission issued an order stating that the refund should not have been ordered. In May 2008, FortisOntario repaid the refunded amounts to NIMO.

Excluding the impact of the receipt of the $3 million refund in 2007 and its subsequent repayment in 2008, revenue increased $5 million year over year. The increase was primarily due to: (i) the flow through to customers of higher energy supply costs at FortisOntario; (ii) a 1.8 per cent increase in basic electricity rates at Maritime Electric, effective April 1, 2008; and (iii) an average 1.1 per cent increase in basic electricity distribution rates at FortisOntario, effective May 1, 2008, partially offset by the impact of lower electricity sales.

Earnings: Earnings were $2 million lower than the previous year. Excluding the impact of the receipt of the refund in 2007 and its subsequent repayment in 2008, earnings were $2 million higher year over year. The increase was driven by higher basic electricity rates, lower operating expenses and lower effective corporate taxes, partially offset by the impact of lower electricity sales and higher finance charges associated with increased borrowings. Operating expenses in 2007 included costs associated with an early retirement program at FortisOntario.

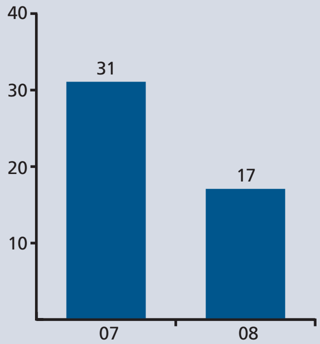
In October 2008, FortisOntario entered into a definitive agreement to acquire a 10 per cent strategic ownership in the electricity distribution business of Grimsby Power Inc. for a cash payment of approximately $1 million plus the provision of services to integrate Grimsby Power Inc.'s customer information system with FortisOntario's system. Grimsby Power Inc. serves approximately 10,000 distribution customers in the western area of the Niagara region. The transaction has been approved by the Ontario Energy Board ("OEB") and is pending approval from the Ontario Ministry of Finance.

Outlook: In March 2009, Maritime Electric received regulatory approval of its 2009 Rate Application, which will result in an increase in the amount of energy-related costs to be collected from customers through the basic rate component of customer billings, effective April 1, 2009. The regulator also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer rates for 2009 will be an increase of 5.3 per cent based on average consumption of 650 kWh per month.

Canadian Niagara Power filed a 2009 Cost of Service Application in August 2008 requesting the rebasing of distribution rates using 2009 as a forward test year. The application assumes a deemed capital structure of 56.7 per cent debt and 43.3 per cent equity and, as required by the OEB, reflects a preliminary ROE of 8.39 per cent. The Company expects a decision on the application to be received in April 2009.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Other Canadian Electric Utilities is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Other Canadian Electric Utilities for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Regulated Electric Utilities – Caribbean Earnings *($ millions)*



Regulated Electric Utilities – Caribbean

Earnings' contribution from Regulated Electric Utilities – Caribbean for 2008 was $17 million (2007 – $31 million), which represented approximately 7 per cent of the Corporation's total regulated earnings (2007 – 15 per cent). Regulated Electric Utilities – Caribbean assets were approximately $1.0 billion as at December 31, 2008 (December 31, 2007 – $0.8 billion), which represented approximately 10 per cent of the Corporation's total regulated assets as at December 31, 2008 (December 31, 2007 – 8 per cent).

Regulated Electric Utilities – Caribbean(1)

Financial Highlights

Years Ended December 31	2008(2)	2007	Variance
Average US:CDN Exchange Rate(3)	**1.08**	1.07	0.01
Electricity Sales *(GWh)*	**1,199**	1,054	145
($ millions)			
Revenue	**408**	307	101
Energy Supply Costs	**273(4)**	169	104
Operating Expenses	**55**	49(5)	6
Amortization	**36**	28	8
Finance Charges	**16**	15	1
Corporate Taxes	**2**	2	–
Non-Controlling Interest	**9**	13	(4)
Earnings	**17**	31	(14)

(1) Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos

(2) Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008.

(3) The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00 = US$1.00. The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar.

(4) Energy supply costs during 2008 included an $18 million (BZ$36 million) charge as a result of a regulatory rate decision by the Public Utilities Commission of Belize in June 2008.

(5) Operating expenses during 2007 included a $4.4 million (US$3.7 million) charge on the disposal of steam-turbine assets at Caribbean Utilities.

Electricity Sales: Electricity sales at Regulated Electric Utilities – Caribbean increased 145 GWh, or 13.8 per cent, year over year, driven by two additional months of contribution from Caribbean Utilities related to a change in the utility's fiscal year end, and customer and general economic growth. The increase was tempered by the loss of electricity sales at Fortis Turks and Caicos as a result of Hurricane Ike, including the delayed reopening for the fall tourist season of several large hotels on the Turks and Caicos Islands. Hurricane Ike was a Category 4 hurricane which struck the Turks and Caicos Islands in early September 2008. The increase was also tempered by the impact on electricity sales associated with the reduction in tourism activities related to global economic conditions towards the end of 2008.

Excluding the two additional months of contribution from Caribbean Utilities, electricity sales increased 6.0 per cent year over year. Electricity sales increased 8.7 per cent in 2007 compared to 2006.

Revenue: Revenue increased $101 million over the previous year; however, annual revenue for 2008 included the two additional months of contribution from Caribbean Utilities and an approximate $6 million favourable impact of foreign currency translation due to the weakening of the Canadian dollar against the US dollar year over year. Excluding the two additional months of contribution from Caribbean Utilities and the favourable impact of foreign currency translation, revenue increased year over year primarily due to: (i) the full flow through of higher fuel and oil costs to customers at Caribbean Utilities under the terms of the Company's new T&D licence; (ii) electricity sales growth; and (iii) an increase in the cost of power component of the average electricity rate at Belize Electricity, effective July 1, 2008. Partially offsetting the above factors were: (i) a decrease in the value-added delivery ("VAD") component of the average electricity rate at Belize Electricity, effective July 1, 2008; (ii) a 3.25 per cent reduction in basic electricity rates and the elimination of the hurricane cost recovery surcharge ("CRS") at Caribbean Utilities, effective January 1, 2008, under the terms of the Company's new T&D licence; and (iii) revenue loss of approximately $2 million at Fortis Turks and Caicos due to Hurricane Ike.

Earnings: Earnings' contribution was $14 million lower than the previous year. Earnings' contribution in 2008 was reduced by $13 million, representing the Corporation's approximate 70 per cent share of $18 million (BZ$36 million) of previously incurred fuel and purchased power costs at Belize Electricity disallowed by the regulator. Earnings' contribution in 2007 was reduced by approximately $2 million, representing the Corporation's share of a charge on the disposal of steam-turbine assets at Caribbean Utilities.

Excluding the one-time items in 2008 and 2007, as described above, earnings were $3 million lower year over year. The impact of electricity sales growth, $1 million of additional earnings' contribution from Caribbean Utilities, and the favourable impact on energy supply costs associated with the movement in deferred fuel costs at Caribbean Utilities was more than offset by: (i) the impact of the 3.25 per cent reduction in basic electricity rates and the elimination of the hurricane CRS at Caribbean Utilities; (ii) the reduction in the VAD component of the average electricity rate at Belize Electricity; (iii) revenue loss of approximately $2 million at Fortis Turks and Caicos due to Hurricane Ike; and (iv) increased operating expenses and amortization costs.

A large portion of the costs of reconnecting customers and restoring electricity service at Fortis Turks and Caicos as a result of Hurricane Ike was capital in nature and, therefore, did not affect earnings.

Excluding the impact of foreign currency translation and the charge on the disposal of steam-turbine assets in 2007, operating expenses increased mainly due to the impact of hiring additional employees and increased general and administrative expenses at Fortis Turks and Caicos, and the timing of maintenance activities. Amortization costs increased as a result of continued investment in capital assets.

In addition to the $18 million charge described above, Belize Electricity's targeted allowed ROA was reduced to 10 per cent from 12 per cent, effective July 1, 2008, which was reflected through a reduction in the VAD component of the average electricity rate.

In April 2008, Caribbean Utilities and the Government of the Cayman Islands entered into a new exclusive 20-year T&D licence and a new non-exclusive 21.5-year generation licence. Under the new T&D licence, customer rates are being set using an initial targeted ROA of 10 per cent, down from 15 per cent as allowed under the previous licence, which was reflected through the reduction in basic electricity rates, effective January 1, 2008.

Outlook: Growth in annual electricity sales at the Corporation's regulated utilities in the Caribbean for 2009 is expected to be approximately 4 per cent, reflecting the anticipated continued global economic downturn that is negatively affecting activity in the tourism, oil and related industries in the Caribbean region.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Regulated Electric Utilities – Caribbean is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Regulated Electric Utilities – Caribbean segment for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

NON-REGULATED

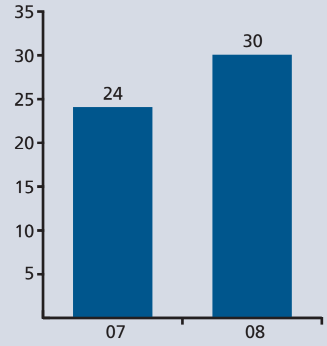
Non-Regulated – Fortis Generation(1)

Financial Highlights

Years Ended December 31	**2008**	2007	Variance
Energy Sales *(GWh)*	**1,217**	1,122	95
($ millions)			
Revenue	**82**	75	7
Energy Supply Costs	**7**	8	(1)
Operating Expenses	**14**	14	–
Amortization	**10**	10	–
Finance Charges	**8**	10	(2)
Corporate Taxes	**10**	8	2
Non-Controlling Interest	**3**	1	2
Earnings	**30**	24	6

(1) Includes the operations of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State.

Non-Regulated – Fortis Generation Earnings *($ millions)*



Energy Sales: Energy sales from Non-Regulated – Fortis Generation increased 95 GWh, or 8.5 per cent, year over year, driven by higher production in central Newfoundland, Belize and Upper New York State. Higher production was mainly the result of higher rainfall.

Revenue: Revenue was $7 million higher year over year. Factors increasing revenue were: (i) higher production; (ii) increased average wholesale energy prices per megawatt hour ("MWh") in Ontario, which were $48.83 for 2008 compared to $47.81 for 2007; and (iii) increased average wholesale energy prices per MWh in Upper New York State, which were US$71.00 for 2008 compared to US$60.73 for 2007.

Earnings: Earnings were $6 million higher year over year, reflecting increased production and lower finance charges driven by the refinancing, in November 2007, of higher-cost external debt with lower-cost inter-company borrowings. Higher average wholesale energy prices also contributed to the increase in earnings year over year.

Outlook: Construction continued in 2008 on the US$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize. The facility is expected to come into service at the beginning of 2010. The earnings' contribution from the Vaca facility, combined with the Corporation's planned consolidated capital program over the next couple of years, are expected to more than offset the loss of earnings upon the expiration, in April 2009, of the Niagara Exchange Agreement associated with the Rankine hydroelectric generating station in Ontario.

Further information on the Vaca hydroelectric generating facility and a summary of forecast non-regulated utility capital expenditures for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

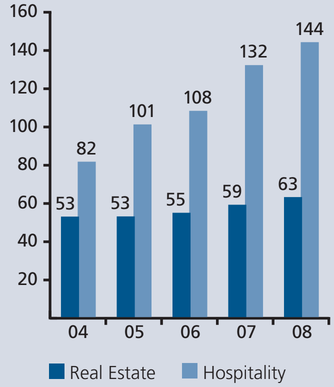
Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31

($ millions)	**2008**	2007	Variance
Hospitality Revenue	**144**	132	12
Real Estate Revenue	**63**	59	4
Total Revenue	**207**	191	16
Operating Expenses	**135**	123	12
Amortization	**15**	14	1
Finance Charges	**24**	24	–
Corporate Taxes	**10**	6	4
Earnings	**23**	24	(1)

Fortis Properties
Revenue *($ millions)*



Revenue: Hospitality revenue was $12 million higher than the previous year, reflecting revenue contribution from the Delta Regina, acquired in August 2007, and the Fairmont Newfoundland hotel, which was acquired for approximately $22 million in November 2008 and rebranded the Sheraton Hotel Newfoundland in January 2009. Hospitality revenue also increased year over year due to improved performance at the Company's operations in Atlantic Canada.

Revenue per available room ("REVPAR") for 2008 was $80.39 compared to $79.31 for 2007. The increase in REVPAR was mainly due to higher average room rates, partially offset by decreased occupancy, at all of the Company's hospitality operating regions.

Real Estate revenue was $4 million higher year over year. The growth in Real Estate revenue was attributable to enhanced performance throughout all of the real estate operating regions, as well as the contribution from the real estate operations of the Delta Regina since August 2007. The occupancy rate of the Real Estate Division was 96.8 per cent as at December 31, 2008, consistent with the rate as at December 31, 2007.

Earnings: Earnings were $1 million lower than the previous year. Excluding a $2 million favourable corporate tax adjustment in 2007 associated with opening future income tax liability balances as a result of lower enacted corporate income tax rates, earnings were $1 million higher year over year. The increase was mainly due to a full year of earnings from the Delta Regina, which was acquired in August 2007.

Outlook: The Hospitality Division currently operates in eight Canadian provinces. Achieving organic revenue and earnings' growth at the Hospitality Division may prove challenging in 2009 as a result of the anticipated continued downturn in the global economy and its overall impact on leisure and business travel and hotel stays.

The Real Estate Division operates primarily in Atlantic Canada, with the majority of its properties located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates to reduce the risk of vacancy exposure.

Corporate and Other(1)

Financial Highlights

Years Ended December 31

($ millions)	**2008**	2007(1)	Variance
Revenue	**26**	22	4
Operating Expenses	**16**	13	3
Amortization	**8**	6	2
Finance Charges(2)	**80**	70	10
Corporate Tax Recovery	**(23)**	(12)	(11)
Preference Share Dividends	**14**	6	8
Net Corporate and Other Expenses	**(69)**	(61)	(8)

(1) Includes Fortis net corporate expenses and, from May 17, 2007, the net expenses of non-regulated Terasen corporate-related activities and the financial results of Terasen's 30 per cent ownership interest in CWLP and Terasen's non-regulated wholly owned subsidiary TES

(2) Includes dividends on preference shares classified as long-term liabilities

Revenue: Revenue was $4 million higher than the previous year. Higher interest revenue from increased inter-company lending was combined with increased revenue contributions from CWLP. CWLP contributed revenue for a full year in 2008 compared to a partial year in 2007; however, this increase was partially offset by the impact of a decrease in the number of customer contracts at CWLP.

Net Corporate and Other Expenses: Net corporate and other expenses were $8 million higher than the previous year, primarily due to Terasen acquisition-related finance charges and other Terasen corporate-related expenses for a full year in 2008 compared to a partial year in 2007. The increase also reflected higher preference share dividends associated with the 9.2 million First Preference Shares, Series G issued in the second quarter of 2008 for gross proceeds of $230 million and higher business development costs. The increase in net corporate and other expenses was partially offset by a higher corporate tax recovery and higher interest revenue from increased inter-company lending. The corporate tax recovery in 2008 was favourably impacted by a $2 million tax reduction associated with the settlement of historical corporate tax matters at Terasen. The corporate tax recovery in 2007 was reduced as a result of purchase price allocation tax adjustments and by the impact of lower enacted future corporate income tax rates.

In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately $300 million. The net proceeds were used to repay short-term debt that was primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008 and for general corporate purposes.

Outlook: While currently not significant, financial results of TES are also reported in the Corporate and Other segment. TES expects to increase its activities in the development, building, owning and operating of geothermal energy systems, community piping and energy transfer systems to harness renewable energy sources. TES is entering into agreements with developers to provide alternative thermal energy systems for both residential and commercial development projects in British Columbia. In October 2008, TES signed an agreement to build a centralized heating and cooling system for a new Okanagan lakefront community project. TES will own and operate this alternative energy system. In December 2008, TES signed an agreement to build and manage an alternative district energy system in Coquitlam, British Columbia. The project is expected to commence in the fall of 2009 and be operational as early as 2011.

Regulatory Highlights

The nature of regulation and summary of material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities are summarized as follows:

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2007	2008	2009	Supportive Features / Future or Historical Test Year Used to Set Rates
				ROE		Cost of Service ("COS")/ROE
						PBR mechanism through 2009:
TGI	BCUC	35	8.37	8.62	8.47	TGI: 50/50 sharing of earnings above or below the allowed ROE
TGVI	BCUC	40	9.07	9.32	9.17	TGVI: 100 per cent retention of earnings from lower-than-forecasted operating and maintenance costs but no relief from increased operating and maintenance costs
						ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
FortisBC	BCUC	40	8.77	9.02	8.87	COS/ROE
						PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account
						ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
FortisAlberta	AUC	37	8.51	8.75	8.51[1]	COS/ROE
						ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	8.60 +/– 50 bps	8.95 +/– 50 bps	8.95 +/– 50 bps	COS/ROE
						ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	10.25	10.00	9.75	COS/ROE
						Future Test Year
FortisOntario	OEB (Canadian Niagara Power)	43.3[2]	9.00	9.00	8.39	Canadian Niagara Power – COS/ROE
	Franchise Agreement (Cornwall Electric)					Cornwall Electric – Price cap with commodity cost flow through
						Future Test Year – beginning in 2009
				ROA		Four-year COS/ROA agreements
Belize Electricity	Public Utilities Commission ("PUC")	N/A	10.00 – 15.00	10.00	10.00[3]	Additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates.
						Future Test Year
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	15.00	9.00 – 11.00	9.00 – 11.00	COS/ROA
						Rate-cap adjustment mechanism based on published consumer price indices
						Under the new licences, the Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane.
						Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings with the Energy Commission	N/A	17.50[4]	17.50[4]	17.50[4]	COS/ROA
						If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year.
						Future Test Year

(1) Interim ROE pending the outcome of the AUC's 2009 Generic Cost of Capital Proceeding
(2) Allowed deemed equity component of the capital structure for 2009. For 2008, the allowed deemed equity component of the capital structure was 46.7 per cent.
(3) Based on the June 2008 Final Decision on Belize Electricity's 2008/2009 rate application
(4) Amount provided under licence. Actual ROAs achieved in 2007 and 2008 were lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
TGI/TGVI	• In December 2007, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2008. Increased mid-stream costs are flowed through to customers without markup. The approved rates also reflected the impact of an increase in the allowed ROE for 2008 to 8.62 per cent and 9.32 per cent for TGI and TGVI, respectively. • On April 1, 2008, final regulatory approval for the construction of the 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island was received for a total estimated cost of approximately $200 million. • Every three months, TGI and TGVI review natural gas and propane commodity prices with the BCUC in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane. Effective April 1, 2008 and July 1, 2008, the BCUC approved increases in the commodity rates charged to TGI customers for natural gas and propane. Effective October 1, 2008, the BCUC approved decreases in the commodity rates charged to TGI customers for natural gas. The commodity cost of natural gas and propane are flowed through to customers without markup. During 2008, no commodity rate changes were made at TGVI. • In December 2008, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2009. The approved rates also reflected the impact of a decrease in the allowed ROE for 2009 to 8.47 per cent and 9.17 per cent for TGI and TGVI, respectively, resulting from the application of automatic ROE adjustment mechanisms. The commodity rate for natural gas will remain unchanged and the commodity rate for propane will decrease effective January 1, 2009. • TGI filed an application with the BCUC in the fourth quarter of 2008 requesting approval to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond. TGI expects to receive regulatory approval for this $27 million project in early 2009 with completion of the project anticipated in 2010. • TGI and TGVI are currently preparing rate applications related to 2010 which are anticipated to be filed with the BCUC in the second quarter of 2009. The BCUC approval of rates for 2010 and future years will be required as the current PBR agreements expire at the end of 2009. As part of the rate filings, TGI and TGVI plan to seek a review of the current generic ROE adjustment mechanisms and the deemed equity component of the utilities' capital structures.
FortisBC	• In December 2007, regulatory approval was received for the NSA associated with 2008 revenue requirements resulting in a customer rate increase of 2.9 per cent, effective January 1, 2008. The rate increase was primarily the result of the Company's capital expenditure program. Rates for 2008 reflected an allowed ROE of 9.02 per cent. • In April 2008, the BCUC approved an interim increase of 0.8 per cent to FortisBC's customer rates, effective May 1, 2008, as a result of BC Hydro's interim rate increase, which increased FortisBC's cost to purchase power from BC Hydro by 5.06 per cent. • In June 2008, FortisBC filed its 2009 and 2010 Capital Expenditure Plan for gross capital expenditures of approximately $193 million for 2009 and $196 million for 2010. In November 2008, the BCUC denied the costs relating to the Copper Conductor Replacement Project and Advanced Metering Infrastructure Project included in the 2009 and 2010 Capital Expenditure Plan. These projects would have totalled approximately $21 million in 2009 and $27 million in 2010. In February 2009, the BCUC issued its decision on the Company's 2009 and 2010 Capital Expenditure Plan. Total gross capital expenditures of $165 million were approved for 2009 and $156 million were approved for 2010. An additional $16 million of capital expenditures is subject to further regulatory processes. • In December 2008, the BCUC approved the Company's 2009 Revenue Requirements Application resulting in a general rate increase of 4.6 per cent, effective January 1, 2009. The rate increase is primarily the result of the Company's capital expenditure program and higher power purchases driven by customer growth and increased electricity demand. Rates for 2009 reflect an allowed ROE of 8.87 per cent as a result of the application of the automatic ROE adjustment mechanism. The approval of the 2009 Revenue Requirements Application also included an extension of the PBR mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a formula incorporating customer growth and inflation, i.e., the consumer price index ("CPI") for British Columbia minus a productivity improvement factor ("PIF") of 3 per cent in 2009, 1.5 per cent in 2010 and 1.5 per cent in 2011. Should inflation be in excess of 3 per cent, the excess is to be added to the PIF, which effectively caps the CPI at 3 per cent.
FortisAlberta	• Effective January 1, 2008, FortisAlberta became regulated by the AUC due to the separation of the Alberta Energy and Utilities Board into two separate regulatory bodies. • In February 2008, regulatory approval was received of the NSA associated with 2008/2009 revenue requirements, resulting in distribution rate increases of 6.8 per cent, effective January 1, 2008, and 7.3 per cent, effective January 1, 2009. The approved NSA includes forecast gross capital expenditures of approximately $264 million for 2008 and $296 million for 2009, primarily to meet customer growth and improve system reliability. The 2008 revenue requirements included in the 2008/2009 NSA were determined using the 2007 allowed ROE of 8.51 per cent. The impact of the increase in the allowed ROE to 8.75 per cent for 2008 was subject to deferral-account treatment and, as such, was recognized as earned in 2008 and will be collected in customer rates in 2009.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In June 2008, the AUC ruled that a review of ROE levels, adjustment mechanisms and utility capital structures in a generic proceeding would be appropriate. In July 2008, the AUC issued its notice of application, preliminary scoping document and minimum filing requirements for the 2009 Generic Cost of Capital Proceeding. The proceeding applies to all gas, electric and pipeline utilities in Alberta that are regulated by the AUC. • In November 2008, FortisAlberta submitted its evidence with respect to the 2009 Generic Cost of Capital Proceeding as requested by the AUC. A hearing is scheduled for the second quarter of 2009. • In December 2008, FortisAlberta received regulatory approval for its 2009 distribution rates to recover approved distribution costs. The result is a distribution rate increase of 8.6 per cent, effective January 1, 2009. The rate increase is slightly higher than the rate increase of 7.3 per cent contemplated in the 2008/2009 NSA due to the deferred recovery in customer rates in 2009 of the increase in the allowed ROE to 8.75 per cent in 2008. The approved rates for 2009 also reflect the impact of the Company's union agreement, which was settled after the 2008/2009 NSA was approved. As directed by the AUC, the Company is to continue using the 2007 allowed ROE of 8.51 per cent for 2009, pending the outcome of the 2009 Generic Cost of Capital Proceeding. • FortisAlberta expects to file a 2010 and 2011 revenue requirements application during the second quarter of 2009.
Newfoundland Power	• In December 2007, the PUB approved the Company's NSA associated with the 2008 general rate application, resulting in an average 2.8 per cent increase in customer rates, effective January 1, 2008. The rate increase was largely driven by higher amortization costs. The rate increase also reflected the impact of an increase in the allowed ROE to 8.95 per cent for 2008. • The PUB-approved NSA also results in, among other things: (i) the amortization of $7.2 million in 2008 and $4.6 million in each of 2009 and 2010 of the remaining $16.4 million balance of the original December 2005 unbilled revenue liability; (ii) amortization of approximately $3.9 million in each of 2008, 2009 and 2010 of previously deferred amortization expense; (iii) amortization over a period of three years to five years of certain deferred regulatory balances; and (iv) for 2008 through 2010, the deferral of variations in purchase power expense caused by differences in the actual unit cost of energy and the unit cost reflected in customer rates to be recovered from, or refunded to, customers through operation of the Company's rate stabilization account. • Effective July 1, 2008, the PUB approved an average 5.9 per cent increase in customer electricity rates, reflecting the flow through to customers, by operation of the rate stabilization account, of variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power. The increase in customer rates had no impact on Newfoundland Power's earnings in 2008. • In November 2008, the PUB approved, as filed, the Company's 2009 Capital Budget Application for approximately $62 million, with approximately half of the proposed capital expenditures relating to replacing aged and deteriorated components of the electricity system. • The Company's allowed ROE of 8.95 per cent remains unchanged for 2009 and, consequently, there has been no change in basic customer rates for 2009.
Maritime Electric	• In January 2008, IRAC approved, as filed, an increase in basic electricity rates of 1.8 per cent, effective April 1, 2008, and approved a maximum allowed ROE of 10.0 per cent for 2008. • In April 2008, IRAC ordered the energy cost adjustment mechanism ("ECAM") amortization period of 12 months to be set at 8 months, effective May 1, 2008. The result is an increase in the flow through in customer rates of the recovery of ECAM over the shorter amortization period. • In September 2008, IRAC approved, as filed, the Company's amendment of approximately $14 million to its 2008 Capital Budget to reflect the construction of a new transmission line to facilitate the expansion of merchant wind development. The project is being financed entirely by customer contributions. • In November 2008, IRAC approved, as filed, the Company's 2009 Capital Budget Application for approximately $20 million, before customer contributions. • In March 2009, IRAC approved Maritime Electric's 2009 Rate Application, which will result in an increase in the amount of energy-related costs to be collected from customers through the basic rate component of customer billings, effective April 1, 2009. The increase in the reference cost of energy in basic rates from 6.73 cents per kWh to 7.7 cents per kWh will result in a decrease in the amount of energy costs to be collected from customers through the operation of the ECAM. Additionally, IRAC approved the deferral of Point Lepreau Nuclear Generating Station replacement energy costs for 2009 and an increase in the amortization period of the ECAM to 12 months, effective April 1, 2009. IRAC also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer rates for 2009 will be an increase of 5.3 per cent based on average consumption of 650 kWh per month.
FortisOntario	• In March 2008, the OEB issued its decision relating to the 2008 Incentive Regulation Mechanism ("IRM") application filed by Canadian Niagara Power. The result was an average 1.1 per cent increase in electricity distribution rates for operations in Fort Erie, Port Colborne and Gananoque, effective May 1, 2008. The increase was comprised of a 2.1 per cent increase for inflation, partially offset by a 1.0 per cent decrease for a productivity adjustment. Under the 2008 IRM, Canadian Niagara Power's capital structure for 2008 was deemed at 53.3 per cent debt and 46.7 per cent equity, as part of the OEB's plan to move to a 60 per cent debt and 40 per cent equity capital structure over a three-year period.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• Effective July 1, 2008, retail rates at Cornwall Electric decreased by approximately 6.2 per cent, attributable to a new 11.5-year wholesale electricity supply contract negotiated with Hydro-Québec Energy Marketing by Cornwall Electric on behalf of its customers. The new long-term agreement replaces an existing short-term contract and ensures reliability of supply and rate stability. • In August 2008, Canadian Niagara Power filed a 2009 Cost of Service Application requesting the rebasing of distribution rates using 2009 as a forward test year. The application assumes a deemed capital structure of 56.7 per cent debt and 43.3 per cent equity and, as required by the OEB, reflects a preliminary ROE of 8.39 per cent. The application proposes distribution rate increases of 4.9 per cent, 9.4 per cent and 7.1 per cent for Fort Erie, Gananoque and Port Colborne, respectively, effective May 1, 2009. The proposed increases are primarily driven by the impact of distribution system upgrades. The hearing process associated with the application commenced during the fourth quarter of 2008 and the Company expects a decision on the application to be received in April 2009.
Belize Electricity	• In March 2008, the newly elected Government of Belize repealed December 2007 amendments to the *Electricity (Tariffs, Charges and Quality of Services Standards) Bylaws*. The amendments had simplified Belize Electricity's rate-setting methodology, allowed for improved rate stabilization and settled outstanding matters related to the PUC's Final Decision on electricity rates for the period July 1, 2007 through June 30, 2008. • In March 2008, Belize Electricity filed an application requesting an increase in the cost of power component of the average electricity rate by 15 per cent, or BZ6.5 cents per kilowatt hour ("kWh"), as a result of the rapid increase in the cost of power due to increasing world oil prices. The application was disallowed by the PUC which cited that, in the interim, a decrease in the Company's operating expenses and capital expenditure levels would help offset the impact on cash flow of the increasing cost of power. Additionally, the PUC indicated it would defer its detailed analysis of the high deferrals of cost of power into Belize Electricity's cost of power rate stabilization account ("CPRSA") until the Annual Tariff Review Proceeding for the annual tariff period for July 1, 2008 to June 30, 2009. • In April 2008, Belize Electricity filed its Annual Tariff Review Application for the annual tariff period from July 1, 2008 to June 30, 2009 ("2008/2009 Rate Application") requesting a 13.4 per cent increase in the average electricity rate, as a result of an increase in the cost of power component of the rate and an increase in the recovery of the CPRSA. • In May 2008, the PUC issued its Initial Decision on Belize Electricity's 2008/2009 Rate Application. The Initial Decision denied any average rate increase and approved, among other things, a retroactive adjustment to Belize Electricity's CPRSA. Belize Electricity objected to the Initial Decision, which resulted in a review of the Initial Decision by a PUC-appointed Independent Expert. The report of the Independent Expert reiterated many of Belize Electricity's concerns pertaining to the Initial Decision. • In June 2008, the PUC issued its Final Decision on Belize Electricity's 2008/2009 Rate Application which rejected most of the recommendations of the Independent Expert and failed to increase the overall average electricity rate. The PUC also ordered a BZ$36 million retroactive adjustment associated with Belize Electricity's prior years' financial results. The adjustment, in substance, represented the disallowance of previously incurred fuel and purchased power costs. The PUC also reduced Belize Electricity's targeted allowed ROA to 10 per cent from 12 per cent through a reduction in the VAD component of the average electricity rate. The Final Decision would have the impact of reducing the Corporation's share of Belize Electricity's earnings by approximately $5 million over a 12-month period. The Final Decision does not impact the Corporation's non-regulated generation operations in Belize. • As a direct result of the Final Decision, Belize Electricity recorded an $18 million (BZ$36 million) charge ($13 million of which was the Corporation's share) to energy supply costs during the second quarter of 2008. • The Final Decision also proposed the use of an automatic mechanism, to be finalized by the PUC, to adjust monthly, on a two-month lag basis, the cost of power component of the rate to reflect actual costs of power. The automatic adjustment mechanism, which was retroactive effective September 1, 2008, allows for the collection from, or rebate to, customers of actual costs of power which vary from a reference cost of power by more than a threshold of 10 per cent. • In February 2009, the PUC amended the Final Decision on Belize Electricity's 2008/2009 Rate Application (the "Amendment"), effective for the period from January 1, 2009 through June 30, 2009. The Amendment provides for an increase in the VAD component of the average electricity rate to allow Belize Electricity to earn a targeted allowed ROA of 12 per cent but reduces the reference cost of power component of the average electricity rate, due to an overall decline in the cost of power. The Amendment, therefore, allows for an overall decrease in the average electricity rate from BZ44.1 cents per kWh to BZ37.5 cents per kWh. The Amendment also provides for a lower regulated asset value upon which the allowed ROA is calculated, while increasing operating expenses by the same amount, and reduces depreciation, taxes and fees and the related revenue requirement. • Changes made in electricity legislation by the Government of Belize and the PUC and the June 2008 Final Decision and Amendment, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. The judicial process is ongoing with interim rulings, judgments and appeals. The timing or likely outcome of the proceedings is indeterminable at this time.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Caribbean Utilities	• In December 2007, an Agreement in Principle ("AIP") was reached with the Government of the Cayman Islands on the terms of a new exclusive T&D licence and a new non-exclusive generation licence. • In April 2008, the new licences were granted. The terms of the new licences included competition for future generation capacity and general promotion of renewable sources of energy. The T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The generation licence is for a period of 21.5 years, expiring September 2029. The terms of the new licences remained substantially the same as the terms outlined in the AIP. • Effective January 1, 2008, as a result of the AIP and subsequent granting of the new licences, basic customer rates were reduced by 3.25 per cent, the hurricane CRS was removed, a fuel-duty rebate funded by the Government of the Cayman Islands was implemented for residential customers consuming less than 1,500 kWh monthly, and basic rates were restructured to extract all fuel costs and licence fee amounts which are now being flowed through to customers. The 3.25 per cent reduction in basic rates reduced annual revenue by approximately US$2.1 million. Additionally, Caribbean Utilities has forgone US$2.6 million of revenue in 2008 as a result of the early elimination of the hurricane CRS. A new fuel and oil rate factor was also established to provide for the full flow through of fuel and oil costs to customers. • Following the initial basic rate reduction, customer rates will be frozen until May 31, 2009 and will be subject to annual review and adjustment each June thereafter. Under the new T&D licence, a mechanism will be used to adjust basic rates in accordance with a formula that is based on published CPIs, thereby taking inflation into account. The rate-adjustment mechanism is designed to maintain Caribbean Utilities' allowed ROA in a targeted range of 9 per cent to 11 per cent, down from an allowed ROA of 15 per cent permitted under the previous licence. The recently amended *Electricity Regulatory Authority Law* (2005 Revision) provides for the conduct of a competitive bid process to be managed by the ERA for new generating capacity and the replacement of retired generating capacity. The first competitive process under the new generation licence began in May 2008 with a filing of a Certificate of Need by Caribbean Utilities for the installation of 16 MW of additional generating capacity in each of 2011 and 2012. Based on slowing economic growth, the Company has advised the ERA that the capacity is not required until a year later. In March 2009, the ERA approved the Certificate of Need for 16 MW of generating capacity in each of 2012 and 2013. • In July 2008, Caribbean Utilities began a formal request for expressions of interest from qualified wind-generation developers for a wind-generation project for up to 10 MW. The ERA has endorsed this initiative and any power purchase agreements or generating licence arising from this initiative will be subject to ERA approval. • In July 2008, Caribbean Utilities filed with the regulator a Five-Year Capital Investment Plan ("CIP") totalling US$255 million. • In December 2008, Caribbean Utilities filed with the regulator a revised Five-Year CIP as a result of the change in the Company's fiscal year end. The revised CIP still totalled US$255 million, including approximately US$72 million related to new generation that is expected to be solicited. In January 2009, the regulator requested that the Company further review its non-generation capital expenditures to reflect the current economic environment and lower growth projections. A revised CIP totalling US$246 million was subsequently submitted to the ERA. A decision on the revised CIP is expected during the first quarter of 2009. • In January 2009, the ERA approved a new customer-owned renewable energy tariff that will allow customers on Grand Cayman to connect renewable energy systems to the Company's distribution system and generate their own power from renewable energy while remaining connected to Caribbean Utilities' grid. The Company expects to be able to connect customers to the grid by the end of the first quarter of 2009.
Fortis Turks and Caicos	• In May 2008, Fortis Turks and Caicos received approval from the Government of the Turks and Caicos Islands to supply wholesale electricity under an exclusive licence to Dellis Cay on the Turks and Caicos Islands. • In March 2009, Fortis Turks and Caicos submitted its 2008 annual regulatory filing outlining the Company's performance in 2008 and its capital expansion plans for 2009.

Consolidated Financial Position

The following table outlines the significant changes in the consolidated balance sheets of Fortis between December 31, 2008 and December 31, 2007.

Significant Changes in the Consolidated Balance Sheets between December 31, 2008 and December 31, 2007

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Accounts receivable	46	The increase was primarily due to the impacts of cooler weather and an increase in the commodity cost of natural gas charged to customers at the Terasen Gas companies in December 2008 compared to December 2007.
Regulatory assets – current and long-term	48	The increase was driven by the deferral of 2008 AESO charges at FortisAlberta, an increase in the deferral of other post-employment benefit costs and the deferral of an increase in the cost of fuel and power at Maritime Electric and Caribbean Utilities. The increase was partially offset by a decrease in the deferral of the commodity cost of natural gas at the Terasen Gas companies and the cost of fuel and purchased power at Belize Electricity. The decrease at Belize Electricity was driven by an $18 million (BZ$36 million) adjustment as a result of a regulatory rate decision in 2008.
Inventories	22	The increase was primarily associated with inventories of natural gas at the Terasen Gas companies due to an increase in the average price of natural gas in December 2008 compared to December 2007.
Deferred charges and other assets	100	The increase was mainly due to the reclassification of hydroelectric generating facility assets of the Exploits Partnership from utility capital assets as at December 31, 2008. The increase was also due to $31 million in contributions made by FortisAlberta to the AESO for transmission capital projects during 2008 and an increase in deferred defined benefit pension costs. Refer to the "Contingencies" section of this MD&A for a further discussion of the Exploits Partnership.
Future income tax assets – long-term	17	The increase primarily related to future income tax recoveries associated with unrealized foreign exchange losses incurred upon the translation of the Corporation's US dollar-denominated long-term debt due to the weakening of the Canadian dollar against the US dollar.
Utility capital assets	619	The increase primarily related to $890 million invested in electricity and gas systems combined with the impact of foreign exchange on the translation of foreign currency-denominated utility capital assets. The increase was partially offset by customer contributions and amortization for 2008 and the reclassification of hydroelectric generating facility assets of the Exploits Partnership to deferred charges and other assets as at December 31, 2008.
Income producing properties	22	The increase primarily related to the acquisition of the Fairmont Newfoundland hotel in November 2008.
Goodwill	31	The increase primarily related to the impact of foreign exchange on the translation of US dollar-denominated goodwill and goodwill associated with the Corporation's additional investment in Caribbean Utilities as a result of the Corporation's participation in Caribbean Utilities' Rights Offering in August 2008. The increase was partially offset by a $6 million reduction associated with the recognition in 2008 of the benefit of tax losses at Terasen which related to periods prior to the Corporation's ownership of Terasen.
Short-term borrowings	(65)	The decrease was primarily due to the repayment of short-term borrowings by Maritime Electric and TGI with proceeds from the issuance of long-term debt.
Accounts payable and accrued charges	81	The increase was primarily due to higher natural gas costs payable at the Terasen Gas companies due to increased consumption as a result of cooler weather in December 2008 compared to December 2007, combined with higher accounts payable at Maritime Electric due to the timing of payments of energy supply costs. The increase was partially offset by a decrease in amounts owing at FortisAlberta due to the timing of payments to the AESO for transmission costs.
Income taxes payable	36	The increase was mainly due to taxes associated with regulatory-deferral accounts at the Terasen Gas companies combined with the timing of income tax payments and the accrual of current income taxes at the Terasen Gas companies and Newfoundland Power. The increase was partially offset by an approximate $17 million payment associated with the Québec Trust tax settlement at Terasen.
Regulatory liabilities – current and long-term	54	The increase was driven by the deferral, during the latter part of 2008, of amounts owing to customers due to lower actual commodity cost of natural gas at the Terasen Gas companies and lower cost of fuel and purchased power at Belize Electricity compared to amounts collected in customer rates and an increase in the regulatory provision for future asset removal and site restoration costs. The increase was partially offset by a decrease in the unbilled revenue liability at Newfoundland Power in accordance with PUB-approved amortization.
Deferred credits	16	The increase was primarily due to an increase in supplementary defined benefit pension and other post-employment benefit liabilities.

Significant Changes in the Consolidated Balance Sheets between December 31, 2008 and December 31, 2007 (cont'd)

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Long-term debt and capital lease obligations (including current portion)	65	The increase was primarily due to the issuance of long-term debt and the impact of foreign exchange on the translation of foreign currency-denominated debt, partially offset by a net decrease in committed credit-facility borrowings, as well as by regularly scheduled debt maturities and repayments. The issuance of long-term debt, primarily to repay committed credit-facility borrowings, short-term borrowings and maturing long-term debt, was comprised of a $250 million unsecured debenture offering by TGI, a $250 million unsecured debenture offering by TGVI, a $100 million senior unsecured debenture offering by FortisAlberta and a $60 million secured first mortgage bond issue by Maritime Electric. The net $309 million decrease in committed credit-facility borrowings was driven by net repayments at the Terasen Gas companies and the Corporation, partially offset by net borrowings at FortisAlberta and FortisBC. The regularly scheduled debt repayments included the repayment of $188 million of maturing debt at TGI and $200 million of maturing debt at Terasen Inc.
Non-controlling interest	30	The increase primarily related to the impact of foreign exchange on the translation of foreign currency-denominated non-controlling interest amounts, combined with the Corporation's non-controlling interest in Caribbean Utilities' US$28 million Rights Offering in August 2008. The increase was partially offset by the Corporation's non-controlling interest in the net loss incurred at Belize Electricity in 2008, which was mainly the result of the PUC's decision on the Company's 2008/2009 Rate Application.
Shareholders' equity	670	The increase was driven by a $300 million common share issue ($291 million net of after-tax expenses) and a $230 million preference share issue ($225 million net of after-tax expenses), combined with net earnings reported for 2008, less common share dividends. The remainder of the increase related to the issuance of common shares under the Corporation's share purchase, dividend reinvestment and stock option plans and a decrease in accumulated other comprehensive loss.

Liquidity and Capital Resources

The table below outlines the Corporation's sources and uses of cash in 2008, as compared to 2007, followed by a discussion of the nature of the variances in cash flows year over year.

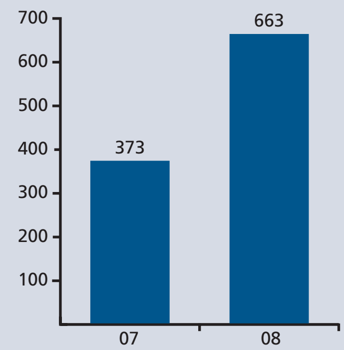
Summary of Cash Flows

Years Ended December 31

($ millions)	**2008**	2007	Variance
Cash, Beginning of Year	**58**	41	17
Cash Provided By (Used In)			
Operating Activities	**663**	373	290
Investing Activities	**(854)**	(2,033)	1,179
Financing Activities	**196**	1,680	(1,484)
Foreign Currency Impact on Cash Balances	**3**	(3)	6
Cash, End of Year	**66**	58	8

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2008 was $290 million higher than the previous year. An increase in cash flow from operating activities, after working capital adjustments, of $380 million at the Terasen Gas companies was combined with the impact of favourable working capital changes at Newfoundland Power. The Terasen Gas companies contributed to the financial results of the Corporation for a full year in 2008 compared to a partial year in 2007. The increase was partially offset by lower cash flow from operating activities, after working capital adjustments, at FortisAlberta. However, cash from operating activities in 2007 at FortisAlberta reflected the favourable impact of the sale of amounts in the Company's AESO charges deferral account, corporate tax refunds received and the timing of the payment of AESO transmission costs.

Cash Flow from Operating Activities
($ millions)



Investing Activities: Cash used in investing activities in 2008 was approximately $1.2 billion lower than the previous year. Investing activities in 2007, however, included the impact of the approximate $1.3 billion cash payment for the acquisition of Terasen in May 2007 and the approximate $50 million acquisition of the Delta Regina in August 2007. Excluding the impact of the acquisitions of Terasen and the Delta Regina in 2007, cash used in investing activities was $124 million higher year over year. The increase was driven by higher utility capital expenditures and changes in deferred charges, other assets and deferred credits, partially offset by an increase in contributions received in aid of construction and an increase in proceeds from the sale of capital assets. In January 2008, TGI received $14 million of proceeds associated with the sale of surplus land in December 2007. Investing activities for 2008 also included the approximate $22 million acquisition of the Fairmont Newfoundland hotel in November 2008.

Gross utility capital expenditures in 2008 were $890 million, $100 million higher than last year. The increase was driven by the Terasen Gas companies and FortisAlberta, partially offset by lower capital spending at FortisBC. The net increase in the use of cash associated with changes in deferred charges, other assets and deferred credits of $27 million was driven by higher contributions by FortisAlberta to AESO transmission capital projects. Contributions received in aid of construction in 2008 were $12 million higher than last year, primarily related to the Terasen Gas companies and Maritime Electric, partially offset by lower contributions received at FortisAlberta.

Financing Activities: Cash provided by financing activities in 2008 was approximately $1.5 billion lower than the previous year. Financing activities in 2007 included the issuance of common shares, for gross proceeds of $1.15 billion, to finance a significant portion of the cash purchase price of Terasen. Excluding the impact of financing the acquisition of Terasen in 2007, cash provided by financing activities was $382 million lower in 2008 compared to 2007. The decrease was mainly due to higher net repayments of short-term and committed credit-facility borrowings, lower proceeds from long-term debt and higher repayments of long-term debt. The decrease was partially offset by net proceeds from the $300 million common share issue during the fourth quarter of 2008 and the $230 million preference share issue during the second quarter of 2008 compared to net proceeds from a $150 million common share issue during the first quarter of 2007.

Net repayments of short-term borrowings were $69 million for 2008 compared to proceeds from net short-term borrowings of $103 million in 2007. The net repayments in 2008 were driven by Maritime Electric and the Terasen Gas companies, with partial proceeds from the issuance of long-term debt in 2008.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease obligations, and net borrowings (repayments) under committed credit facilities for 2008 compared to 2007 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2008**	2007	Variance
Terasen Gas Companies	**496**[(1)(2)]	250[(3)]	246
FortisAlberta	**99**[(4)]	110[(5)]	(11)
FortisBC	**–**	104[(6)]	(104)
Newfoundland Power	**–**	70[(7)]	(70)
Maritime Electric	**60**[(8)]	–	60
Caribbean Utilities	**–**	48[(9)]	(48)
Corporate – Fortis Inc.	**–**	209[(10)]	(209)
Other	**7**	6	1
Total	**662**	797	(135)

(1) Issued February 2008, $250 million 6.05% Senior Unsecured Debentures by TGVI, due February 2038. The net proceeds were used to repay committed credit-facility borrowings.

(2) Issued May 2008, $250 million 5.80% Medium-Term Unsecured Note Debentures by TGI, due May 2038. The net proceeds were primarily used to repay maturing $188 million 6.20% debentures and short-term borrowings.

(3) Issued October 2007, $250 million 6.00% Medium-Term Unsecured Note Debentures by TGI, due October 2037. The net proceeds were used to repay maturing $250 million 6.50% long-term debt.

(4) Issued April 2008, $100 million 5.85% Senior Unsecured Debentures, due April 2038. The net proceeds were used to repay committed credit-facility borrowings.

(5) Issued January 2007, $110 million 4.99% Senior Unsecured Debentures, due January 2047. The net proceeds were used to repay committed credit-facility borrowings.

(6) Issued July 2007, $105 million 5.90% Senior Unsecured Debentures, due July 2047. The net proceeds were used to repay committed credit-facility borrowings and for general corporate purposes, including capital expenditures.

(7) Issued August 2007, $70 million 5.90% Secured First Mortgage Sinking Fund Bonds, due August 2037. The net proceeds were used to repay committed credit-facility borrowings and maturing $31.5 million 11.875% Secured First Mortgage Sinking Fund Bonds.

(8) Issued April 2008, $60 million 6.05% Secured First Mortgage Bonds, due April 2038. The proceeds were used to repay short-term borrowings.

(9) Issued June 2007, US$30 million 5.65% Senior Unsecured Notes, due June 2022. Issued November 2007, US$10 million 5.65% Senior Unsecured Notes, due June 2022. The net proceeds were used to repay debt and finance capital expenditures.

(10) Issued September 2007, US$200 million 6.60% Senior Unsecured Notes, due September 2037. The net proceeds were primarily used to repay committed credit-facility borrowings associated with the Terasen acquisition and for general corporate purposes.

Repayment of Long-Term Debt and Capital Lease Obligations

Years Ended December 31

($ millions)	**2008**	2007	Variance
Terasen Gas Companies	**(193)**	(250)	57
Newfoundland Power	**(5)**	(36)	31
Caribbean Utilities	**(11)**	(18)	7
Fortis Generation – BECOL	**–**	(28)	28
Fortis Properties	**(13)**	(20)	7
Corporate – Terasen Inc.	**(200)**	–	(200)
Other	**(9)**	(11)	2
Total	**(431)**	(363)	(68)

Net (Repayments) Borrowings Under Committed Credit Facilities

Years Ended December 31

($ millions)	**2008**	2007	Variance
Terasen Gas Companies	**(261)**	–	(261)
FortisAlberta	**101**	(76)	177
FortisBC	**31**	(21)	52
Newfoundland Power	**(1)**	(2)	1
Corporate	**(179)**	124[(1)]	(303)
Total	**(309)**	25	(334)

(1) Borrowings under the Corporation's committed credit facility during 2007 primarily related to financing, on an interim basis, the remaining $125 million net cash purchase price of Terasen on May 17, 2007, in addition to certain acquisition costs and common share issue costs; to repay certain short-term indebtedness assumed upon the acquisition of Terasen; to finance a significant portion of the cash purchase price of the Delta Regina in August 2007; and in support of general corporate activities. Indebtedness under the credit facility was partially repaid with partial net proceeds from the $150 million common share issue and the issuance of US$200 million unsecured notes.

Borrowings by the utilities under credit facilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt and/or cash from operations. From time to time, proceeds from preference share, common share and long-term debt issues are used to repay borrowings under the Corporation's committed credit facility.

Net proceeds associated with the issuance of common shares under the Corporation's share purchase and stock option plans in 2008 were $21 million compared to $23 million in 2007. In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately $300 million ($287 million net of costs). The net proceeds were used to repay short-term debt primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008, and for general corporate purposes. In May 2007, the Corporation publicly issued 44.3 million common shares for gross proceeds of approximately $1.15 billion ($1.1 billion net of costs) to finance a significant portion of the net cash purchase price of Terasen. In January 2007, 5.17 million common shares were publicly issued for gross proceeds of approximately $150 million ($143 million net of costs). Partial net proceeds from the common share issue in January 2007 were used to repay indebtedness incurred under the Corporation's committed credit facility. The remainder of the net proceeds was utilized to fund equity requirements of the Corporation's regulated electric utilities in western Canada, in support of their respective capital expenditure programs, and for general corporate purposes.

During the second quarter of 2008, the Corporation issued 9.2 million First Preference Shares, Series G for gross proceeds of approximately $230 million ($223 million net of costs). The net proceeds were used to repay $170 million under the Corporation's committed credit facility, to fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes.

Common share dividends were $162 million for 2008, up $34 million from 2007. The increase was due to an increase in the number of common shares outstanding, primarily as a result of the issuance of common shares pursuant to the Terasen acquisition in May 2007 and a higher dividend declared per common share compared to 2007. The dividend declared per common share in 2008 was $1.01, while the dividend declared per common share in 2007 was $0.88.

Preference share dividends increased $8 million year over year as a result of the dividends associated with the $230 million preference shares that were issued during the second quarter of 2008.

Contractual Obligations: Consolidated contractual obligations over the next five years and for periods thereafter, as at December 31, 2008, are outlined in the following table.

Contractual Obligations

As at December 31

($ millions)	**Total**	≤ 1 year	> 1–3 years	4–5 years	> 5 years
Long-term debt(1)	**5,122**	240	319	335	4,228
Brilliant Terminal Station(2)	**63**	3	5	5	50
Gas purchase contract obligations(3)	**466**	416	50	–	–
Power purchase obligations					
FortisBC(4)	**2,829**	40	76	78	2,635
FortisOntario(5)	**561**	45	94	99	323
Maritime Electric(6)	**72**	52	2	2	16
Belize Electricity(7)	**16**	4	4	2	6
Capital cost(8)	**400**	16	41	41	302
Joint-use asset and shared service agreements(9)	**62**	4	7	6	45
Office lease – FortisBC(10)	**19**	1	4	2	12
Operating lease obligations(11)	**166**	18	33	29	86
Other	**25**	4	10	6	5
Total	**9,801**	843	645	605	7,708

(1) In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates. The repayment criteria were met in

2008 and TGVI is expected to make an $8 million repayment on the loans in 2009 (2008 – $6 million). As at December 31, 2008, the outstanding balance of the repayable government loans was $61 million with $8 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the contractual obligations table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGVI's revenue deficiency deferral account and the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

(2) On July 15, 2003, FortisBC began operating the Brilliant Terminal Station ("BTS") under an agreement, the term of which expires in 2056, (unless the Company has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination). The BTS is jointly owned by CPC/CBT and is used by the Company on its own behalf and on behalf of CPC/CBT. The agreement provides that FortisBC will pay CPC/CBT a charge related to the recovery of the capital cost of the BTS and related operating costs.

(3) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2008.

(4) Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the power purchase agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The power purchase agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

(5) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(6) Maritime Electric has two take-or-pay contracts for the purchase of either capacity or energy. These contracts total approximately $72 million through November 30, 2032. The take-or-pay contract with New Brunswick Power ("NB Power") includes, among other things, replacement energy and capacity for the NB Power Point Lepreau Nuclear Generating Station during its refurbishment outage. The other take-or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new International Power Line into the United States.

(7) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity and a two-year power purchase agreement, expiring in December 2010, between Belize Electricity and Comisión Federal de Electricidad of Mexico for the supply of 50 MW of firm capacity and associated energy. Belize Electricity has also signed two 15-year power purchase agreements with Belize Cogeneration Energy Limited ("Belcogen") and Belize Aquaculture Limited that provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively. As the generating plants are not yet connected to the electricity system, the obligations related to the power purchase agreements with Belcogen and Belize Aquaculture Limited have not been included in the Corporation's contractual obligations.

(8) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Nuclear Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

(9) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2013 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also

entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

(10) Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term.

(11) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro Inc.

Other Contractual Obligations: Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-fired generating plant. The contract is for three years terminating in April 2010. The remaining approximate quantities, in millions of imperial gallons, required to be purchased annually for each of the 12-month periods ended December 31 are: 2009 – 27 and 2010 – 9.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Pension Funding: As at December 31, 2008, the fair value of the Corporation's consolidated defined benefit pension plan assets was $579 million compared to $674 million as at December 31, 2007, which represented a 14 per cent decline in asset value. Details of the nature of the changes in the fair value of the plan assets are disclosed in Note 20 to the Corporation's 2008 Consolidated Financial Statements. The decrease in the fair value of the pension plan assets during 2008 was mainly driven by unfavourable market conditions during the year.

The decline in the fair value of the pension plan assets is expected to have the effect of increasing the Corporation's future consolidated defined benefit pension plan funding obligations. The amount of the increase will not be determinable until the next completion of actuarial valuations, which for Newfoundland Power, the Corporation and one of the defined benefit pension plans at Terasen is expected during 2009, related to December 31, 2008 valuation dates. The next scheduled actuarial valuations for the remaining larger defined benefit pension plans are not until December 2009 and December 2010.

Fortis expects any additional defined benefit pension plan funding requirements to be sourced primarily from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

Based on the last completion of actuarial valuations, required defined benefit pension plan funding contributions are expected to total approximately $17 million for 2009 and $12 million for 2010. The level of the defined benefit pension plan funding contributions will be affected by the outcome of the December 31, 2008 actuarial valuations.

Capital Structure: The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure

As at December 31	**2008**		2007	
	($ millions)	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash)(1)	**5,468**	**59.5**	5,476	64.3
Preference shares(2)	**667**	**7.3**	442	5.2
Common shareholders' equity	**3,046**	**33.2**	2,601	30.5
Total	**9,181**	**100.0**	8,519	100.0

(1) Includes long-term debt, including current portion, and short-term borrowings, net of cash

(2) Includes preference shares classified as both long-term liabilities and equity

The improvement in the capital structure from December 31, 2007 was primarily due to a $300 million ($291 million net of after-tax expenses) common share issue in December 2008 and a $230 million ($225 million net of after-tax expenses) preference share issue in the second quarter of 2008. The capital structure was also favourably impacted by net earnings applicable to common shares, net of common share dividends, of $83 million during 2008.

The Corporation's credit ratings are as follows:

Standard & Poor's ("S&P")	A– (long-term corporate and unsecured debt credit rating)
DBRS	BBB(high) (unsecured debt credit rating)

During the fourth quarter of 2008, S&P and DBRS confirmed the Corporation's unsecured corporate debt credit ratings. The credit ratings reflect the diversity of the operations of Fortis, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level and the continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

Capital Program: The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. During 2008, approximately $94 million in maintenance and repairs was expensed compared to approximately $87 million during 2007. The increase year over year largely reflected inclusion of the financial results of the Terasen Gas companies for a full year in 2008.

Actual gross consolidated capital expenditures for 2008 were $904 million, comparable to the estimate for 2008 as disclosed at December 31, 2007.

A summary of gross capital expenditures for 2008 by segment and asset category is provided in the following table.

Gross Capital Expenditures

Year Ended December 31, 2008

($ millions)	Terasen Gas Companies(1)	Fortis Alberta(1)(2)	Fortis BC(1)	Newfoundland Power(1)	Other Regulated Utilities – Canadian(1)	**Total Regulated Utilities – Canadian**	**Regulated Utilities – Caribbean**	**Non-Regulated – Utility(3)**	**Fortis Properties**	**Total(4)**
Generation	–	–	16	5	2	**23**	**37**	**18**	**–**	**78**
Transmission	93	–	47	6	14	**160**	**16**	**–**	**–**	**176**
Distribution	108	220	37	48	27	**440**	**43**	**–**	**–**	**483**
Facilities, equipment, vehicles and other	4	41	7	4	2	**58**	**13**	**10**	**14**	**95**
Information technology	15	41	10	4	1	**71**	**1**	**–**	**–**	**72**
Total	220	302	117	67	46	**752**	**110**	**28**	**14**	**904**

(1) Includes asset removal and site restoration expenditures which are permissible in rate base

(2) Excludes payments of $31 million made to the AESO for investment in transmission capital projects

(3) Includes non-regulated generation, non-regulated gas utility and Corporate capital expenditures

(4) Includes expenditures associated with assets under construction

Gross consolidated capital expenditures for 2009 are expected to be approximately $1 billion. Planned capital expenditures are based on detailed forecasts of customer demand, weather, and cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

A summary of forecast gross capital expenditures for 2009 by segment and by asset category is provided in the following table.

Forecast Gross Capital Expenditures

Year Ending December 31, 2009

($ millions)	Terasen Gas Companies[(1)]	Fortis Alberta[(2)]	Fortis BC[(1)]	Newfoundland Power[(1)]	Other Regulated Utilities – Canadian[(1)]	**Total Regulated Utilities – Canadian**	**Regulated Utilities – Caribbean**	**Non-Regulated – Utility[(3)]**	**Fortis Properties**	**Total[(4)]**
Generation	–	–	22	10	3	**35**	**43**	**34**	**–**	**112**
Transmission	160	–	66	5	2	**233**	**17**	**–**	**–**	**250**
Distribution	87	186	37	42	26	**378**	**36**	**1**	**–**	**415**
Facilities, equipment, vehicles and other	8	22	7	4	1	**42**	**19**	**21**	**33**	**115**
Information technology	32	84	10	4	2	**132**	**3**	**–**	**–**	**135**
Total	287	292	142	65	34	**820**	**118**	**56**	**33**	**1,027**

(1) Includes forecast asset removal and site restoration expenditures which are permissible in rate base

(2) Excludes forecast payments of $31 million to be made to the AESO for investment in transmission capital projects

(3) Includes forecast non-regulated generation, non-regulated gas utility and Corporate capital expenditures

(4) Includes forecast expenditures associated with assets under construction

The percentage breakdown of 2008 actual and 2009 forecast gross capital expenditures among growth, sustaining and other is as follows:

Gross Capital Expenditures

Year Ended December 31

(%)	**Actual 2008**	Forecast 2009
Growth	**49**	45
Sustaining[(1)]	**33**	31
Other[(2)]	**18**	24
Total	**100**	100

(1) Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

(2) Related to facilities, equipment, vehicles, information technology systems and other assets

Significant capital expenditure projects in 2008 and 2009 are summarized in the table below.

Significant Capital Projects

($ millions) **Company**	**Nature of project**	**Actual 2008[(1)]**	Forecast 2009[(1)]	Forecast costs to complete after 2009[(1)]	Year of expected completion
Terasen Gas Companies	Liquefied natural gas storage facility – Vancouver Island	**47**	74	93	2011
	Squamish-to-Whistler pipeline lateral and system conversion	**13**	16	–	2009
	Customer Information System	**–**	14[(2)]	–[(2)]	–[(2)]
	Gateway Infrastructure Project	**–**	15	15	2010
	Fraser River South Bank South Arm Rehabilitation Project	**1**	25	1	2010
FortisAlberta	Automated Meter Infrastructure technology	**17**	73	27	2010
FortisBC	Okanagan Transmission Reinforcement Project	**3**	32	100	2011
	New substations and associated transmission lines	**27**	16	73	2013
	Generation asset Upgrade and Life-Extension Program	**11**	14	39	2012
Caribbean Utilities	New 16-MW diesel-fired generating unit	**8**	21	–	2009
Non-Regulated – Fortis Generation	19-MW Vaca hydroelectric generating facility in Belize	**18**	34	–	Beginning of 2010
Fortis Properties	Expansion of Holiday Inn Express Kelowna	**2**	12	–	Beginning of 2010

(1) Includes allowance for funds used during construction

(2) The total cost and timing of the project are subject to regulatory approval. An application requesting approval of the project is expected in 2009.

In April 2008, TGVI received approval from the BCUC to proceed with the engineering, procurement and construction ("EPC") of the liquefied natural gas ("LNG") storage facility on Vancouver Island for a total cost of approximately $200 million. As a result, the Company entered into an EPC contract with a third party for the construction of the facility. The contract includes approximately $55 million to be paid in US dollars. As a result, TGVI entered into a three-year US dollar forward-purchase contract which will mitigate currency fluctuations on the US dollar portion of the EPC contract. Construction commenced on the LNG storage facility during the second quarter of 2008 with completion of the project expected in late 2011.

TGVI's construction of a 50-kilometre pipeline lateral from Squamish to Whistler continued in 2008 and, as at December 31, 2008, approximately 49 kilometres of the pipeline had been constructed. Originally scheduled to be completed by summer 2008, the pipeline lateral is now expected to be completed in April 2009, later than originally planned due to changes in the way the Company can sequence the pipeline construction as a result of the Government of British Columbia's Sea-to-Sky Highway Improvement Project Plan ("Highway Project"). The pipeline is being built in conjunction with the Highway Project and the pipeline route mainly falls within the highway right of way. Upon completion of the pipeline, the Company will convert the Resort Municipality of Whistler from propane to natural gas during spring and summer of 2009. The total cost of the pipeline lateral and system conversion is expected to be approximately $51 million.

TGI is currently conducting a review of the existing customer care services arrangements with its outsourced provider to ensure the needs of customers will be met in the future. Later in 2009, TGI expects to file an application with the BCUC requesting approval and funding for the development of a replacement customer information system with capital spending related to this project estimated at $14 million for 2009.

As a result of the Government of British Columbia's Gateway Initiative, a regional infrastructure program to improve the movement of people, goods and transit throughout Greater Vancouver, TGI will be required to relocate some of its pipeline system. Total capital spending for the project, which is expected to be fully funded from contributions from the Government of British Columbia, is estimated at approximately $30 million, with $15 million expected to be spent in 2009.

In the fourth quarter of 2008, TGI filed an application with the BCUC requesting approval to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond. TGI expects to receive approval for this project in early 2009 with completion of the project anticipated in 2010. The total capital cost of the project is anticipated to be approximately $27 million.

During the third quarter of 2008, FortisAlberta began the second phase of deployment of the replacement of conventional meters with new Automated Meter Infrastructure ("AMI") technology. This phase is part of an overall $124 million project to convert all of FortisAlberta's customers to AMI technology over a four-year period that began in 2007.

In October 2008, the BCUC approved FortisBC's proposed $141 million Okanagan Transmission Reinforcement Project, which was included in FortisBC's 2009 and 2010 Capital Expenditure Plan. The project relates to upgrading the existing overhead transmission line from 161 kilovolts ("kV") to 230 kV from Vaseux Lake to Oliver and Penticton and building a new 230-kV transmission line from Vaseux Lake to Penticton and a substation. FortisBC anticipates that construction of the project will begin in spring 2009 for expected completion in 2011.

During 2008, work continued at FortisBC on a number of new substations and associated transmission lines. Approximately 82 per cent of capital expenditures after 2009 related to this project are subject to regulatory approval.

Since 1998, FortisBC's hydroelectric generating facilities have been subject to an Upgrade and Life-Extension Program which is forecast to conclude in 2012. Approximately 57 per cent of capital expenditures after 2009 related to this project are subject to regulatory approval.

In April 2008, Caribbean Utilities entered into an agreement to purchase a 16-MW diesel generating unit and related equipment from a supplier in Germany for approximately US$24 million over the period 2008 and 2009, with the unit scheduled for completion in September 2009.

Construction continued in 2008 on the US$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize. The facility is being constructed downstream from the Chalillo and Mollejon hydroelectric generating facilities and is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh. The facility is expected to come into service at the beginning of 2010, slightly later than originally planned due to labour and weather-related delays.

Late in 2008, Fortis Properties commenced the expansion of its Holiday Inn Express Kelowna hotel which includes adding 70 rooms and 4,000 square feet of meeting room space. Completion of the expansion is expected by January 2010 at a total capital cost of approximately $14 million.

Over the next five years, consolidated gross capital expenditures are expected to total approximately $4.5 billion. Approximately $3.1 billion of the capital spending is expected be incurred at the regulated electric utilities, driven by FortisAlberta, FortisBC and the Corporation's regulated utility operations in the Caribbean. Approximately $1.2 billion is expected to be incurred at the regulated gas utilities. Capital expenditures at the regulated utilities are subject to regulatory approval. Non-regulated capital expenditures are expected to total approximately $200 million over the same period.

Cash Flow Requirements: At the operating subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flow available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt issues.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions which may limit their ability to distribute cash to Fortis. Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under its committed credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends.

The Corporation does not expect any significant decrease in subsidiary operating cash flows in 2009 as a result of the anticipated continued downturn in the global economy. The subsidiaries expect to be able to source the cash required to fund their 2009 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be approximately $240 million in 2009 and to average approximately $180 million annually over the next five years. The combination of available credit facilities, as discussed in more detail below, and low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to the capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 Rate Application, Belize Electricity does not meet certain debt covenant financial ratios related to loans with the International Bank for Reconstruction and Development and the Caribbean Development Bank totalling $11 million (BZ$18 million) as at December 31, 2008. The Company has informed the lenders of the defaults and has requested appropriate waivers. Belize Electricity is also in default of certain debt covenants which has resulted in Belize Electricity being prohibited from incurring new indebtedness or declaring dividends.

As a result of legislation passed in 2008 by the Government of Newfoundland and Labrador expropriating most of the Newfoundland assets of Abitibi-Consolidated, the Exploits Partnership is potentially in default of a $61 million term loan. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The term loan, which is non-recourse to Fortis, has been reclassified to current portion of long-term debt on the consolidated balance sheet as at December 31, 2008. A further discussion of the Exploits Partnership is provided in the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Fortis and its subsidiaries, except for Belize Electricity and debt associated with the Exploits Partnership as described above, were in compliance with debt covenants as at December 31, 2008 and are expected to remain compliant in 2009.

Credit Facilities: As at December 31, 2008, the Corporation and its subsidiaries had consolidated credit facilities of $2.2 billion, of which approximately $1.5 billion was unused, including $568 million unused under the Corporation's $600 million committed revolving credit facility. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities.

Approximately $2.0 billion of the total credit facilities are committed facilities, the majority of which have maturities between 2011 and 2013.

In 2009, FortisBC expects to have the term of its committed $100 million 364-day revolving credit facility extended for a further year beyond its original maturity in May 2009. Terasen Inc. expects to renew its $100 million committed revolving credit facility, which matures in May 2009. In March 2009, Maritime Electric renegotiated its $50 million demand credit facility and had it converted into a 364-day revolving committed credit facility.

The cost of renewed and extended credit facilities may increase as a result of current economic conditions and tightened credit markets; however, any increased interest expense and/or fees is not expected to have a material financial impact on the Corporation and its subsidiaries in 2009 as the majority of the committed credit facilities have maturities beyond 2009.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities

As at December 31 *($ millions)*	Corporate and Other	Regulated Utilities	Fortis Properties	**Total 2008**	Total 2007
Total credit facilities	715	1,500	13	**2,228**	2,234
Credit facilities utilized					
Short-term borrowings	–	(410)	–	**(410)**	(475)
Long-term debt	(32)	(192)	–	**(224)**	(530)
Letters of credit outstanding	(1)	(102)	(1)	**(104)**	(159)
Credit facilities available	682	796	12	**1,490**	1,070

At December 31, 2008 and December 31, 2007, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Significant changes in total credit facilities from December 31, 2007 to December 31, 2008 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2008 are detailed in Note 26 to the 2008 Consolidated Financial Statements.

Corporate and Other

Letters of credit of $50 million previously outstanding at Terasen Inc., related to its previously owned petroleum transportation business and secured by a letter of credit from the former parent company, were cancelled during the second quarter of 2008.

Regulated Utilities

In April 2008, FortisBC renegotiated and amended its $150 million unsecured committed revolving credit facility, extending the maturity date of the $50 million portion of the facility to May 2011 from May 2010 and extending the $100 million portion to May 2009 from May 2008. The Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval.

In April 2008, Maritime Electric repaid all outstanding borrowings under its $25 million unsecured credit facility with partial proceeds from a $60 million bond issue. The credit facility matured in May 2008 and was not renewed.

In July 2008, TGI renegotiated, on substantially similar terms, its $500 million unsecured committed revolving credit facility, extending the maturity date of the facility to August 2013 from August 2012.

In August 2008, Newfoundland Power renegotiated, on substantially similar terms, its $100 million committed revolving credit facility, extending the maturity date to August 2011 from January 2009.

In November 2008, First Caribbean International Bank withdrew its credit facility with Belize Electricity, requiring the Company to repay approximately BZ$4 million outstanding under the facility. Scotiabank has also put Belize Electricity on notice that it may not renew its BZ$5 million credit facility with the Company if financial conditions do not show signs of improvement. As at December 31, 2008, the Scotiabank credit facility was undrawn. A continuation of lower energy supply costs should provide Belize Electricity with some liquidity relief in the near term.

Off-Balance Sheet Arrangements

As at December 31, 2008, the Corporation had no off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

Business Risk Management

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to some form of regulation that can affect future revenue and earnings. Management at each utility is responsible for working closely with regulators and local governments to ensure both compliance with existing regulations and the proactive management of regulatory issues.

Approximately 93 per cent of the Corporation's operating revenue was derived from regulated utility operations in 2008 (2007 – 90 per cent), while approximately 83 per cent of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2008 (2007 – 81 per cent). The regulated utilities, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Caribbean Utilities, and Fortis Turks and Caicos, are subject to the normal uncertainties faced by regulated entities. The uncertainties include approvals by the respective regulatory authorities of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base. Generally, the ability of the utilities to recover the actual costs of providing services and earn the approved rates of return depends on achieving the forecasts established in the rate-setting processes. Upgrades of existing gas and electricity systems and facilities and the addition of new infrastructure and facilities require the approval of the regulatory authorities either through the approval of capital expenditure plans or through regulatory approval of revenue requirements for the purpose of setting rates, which include the impact of capital expenditures on rate base and/or cost of service. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed. Capital cost overruns subject to such approvals might not be recoverable. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures, as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and to earn the expected rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, ratings assigned by rating agencies, the issuance and sale of securities, and other matters which may, in turn, negatively affect the results of operations and financial position of the Corporation's utilities.

Although Fortis considers the regulatory frameworks in most of the jurisdictions it operates in to be fair and balanced, uncertainties do exist at the present time. The June 2008 regulatory decision on Belize Electricity's 2008/2009 Rate Application and changes in electricity legislation made by the Government of Belize and the PUC create uncertainty in the regulatory regime and the rate-setting process in Belize and violate both established regulatory practice and contractual obligations made by the Government of Belize at the time Fortis made its initial investment in Belize Electricity.

Regulatory frameworks in Alberta and Ontario have undergone significant changes since the deregulation of electricity generation and the introduction of retail competition. The regulations and market rules in these jurisdictions, which govern the competitive wholesale and retail electricity markets, are relatively new and there may be significant changes in these regulations and market rules that could adversely affect the ability of FortisAlberta and FortisOntario to recover costs or to earn reasonable returns on capital. As these companies and their applicable regulators work through the regulatory processes, it is expected that there will be more certainty in evolving regulatory frameworks and environments.

Although all of the Corporation's regulated utilities currently operate under traditional cost of service and/or rate of return on rate base methodologies, PBR and other rate-setting mechanisms, such as automatic rate of return formulas, are also being employed to varying degrees. A discussion of the impact of changes in interest rates on allowed ROEs is provided in the "Business Risk Management – Interest Rate Risk" section of this MD&A.

TGI, TGVI and FortisBC are regulated by the BCUC and are subject to approved PBR mechanisms. The PBR mechanisms at TGI and TGVI expire in 2009. In December 2008, the PBR mechanism at FortisBC was extended for the periods from 2009 to 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a different formula. The PBR mechanisms provide the utilities an opportunity to earn returns in excess of the allowed ROEs determined by the BCUC. Upon expiry of the PBR mechanisms, there is no certainty as to whether new PBR mechanisms will be entered into or what the particular terms of any renewed PBR mechanisms will be.

Further information on the new PBR mechanism at FortisBC and the nature of regulation and various regulatory matters pertaining to the Corporation's utilities is provided in the "Regulatory Highlights" section of this MD&A.

Operating and Maintenance Risks: The Terasen Gas companies are exposed to various operational risks, such as pipeline leaks; accidental damage to, or fatigue cracks in mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas which could result in significant operational and/or environmental liability. The business of electricity transmission and distribution is also subject to operational risks including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. The infrastructure of the subsidiaries is also exposed to the effects of severe weather conditions and other acts of nature. In addition, a significant portion of the infrastructure is located in remote areas, which may make access difficult for repair of damage due to weather conditions and other acts of nature. The Terasen Gas companies and FortisBC operate facilities in a terrain with a risk of loss or damage from earthquakes, forest fires, floods, washouts, landslides, avalanches and similar acts of nature. The Corporation and its subsidiaries have insurance that provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the respective regulatory authority for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. See the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

The Corporation's gas and electricity systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the utilities determine expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures the utilities believe are necessary to maintain, improve and replace their assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. If actual costs exceed regulator-approved capital expenditures, it is uncertain as to whether any additional costs will receive regulatory approval for recovery in future customer rates. The inability to recover these additional costs could have a material effect on the financial condition and results of operations of the utilities.

Economic Conditions: Typical of utilities, economic conditions in the Corporation's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. Also, in the service territories in which the Terasen Gas companies operate, the growth of new multi-family housing starts is continuing to outpace that of new single-family housing starts. Natural gas has a lower penetration rate in multi-family housing; therefore, gas distribution volumes may not grow as quickly as in the past. In the Caribbean, the level of and fluctuations in tourism and related activities, which are closely tied to economic conditions, influence electricity sales as they affect electricity demand of the large hotels and condominium complexes that are serviced by the Corporation's regulated utilities in that region.

Higher energy prices can result in reduced consumption by customers. Natural gas and crude oil exploration and production activity in certain of the Corporation's service territories are closely correlated with natural gas and crude oil prices. The level of these activities can influence energy demand.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of utility operations, including various mitigating measures approved by regulators, helps to reduce the impact that lower energy demand, associated with poor economic conditions, may have on the utilities' earnings. However, a severe and prolonged downturn in economic conditions could materially affect the utilities, despite regulatory measures available for compensating for reduced demand. For instance, significantly reduced energy demand in the Corporation's service territories could reduce capital spending which would, in turn, impact rate base and earnings' growth.

In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for gas and electricity consumed, thereby affecting the aging and collection of the utilities' trade receivables.

Fortis also holds investments in both commercial real estate and hotel properties. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. Fortis Properties' real estate exposure to lease expiries averages approximately 11 per cent per annum over the next five years. Approximately 57 per cent of Fortis Properties' operating income was derived from hotel investments in 2008 (2007 – 58 per cent). Achieving organic revenue and earnings' growth at the Hospitality Division may prove challenging in 2009 as a result of the anticipated continued downturn in the global economy and its overall impact on leisure and business travel and hotel stays. It is estimated that a 10 per cent decrease in revenue at the Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it, or its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and the financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) will not be sufficient to fund the repayment of all outstanding liabilities when due as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and to repay existing debt.

Generally, the Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt issues and on the Corporation's and its utilities' credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the finance charges of the Corporation and its utilities. Also, a significant downgrade in TGI or Terasen Inc.'s credit ratings could trigger margin calls and other cash requirements under TGI's natural gas purchase and natural gas derivative contracts. As discussed in the "Liquidity and Capital Resources – Capital Structure" section of this MD&A, the Corporation's corporate investment-grade credit ratings were confirmed and maintained during the fourth quarter of 2008. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the current global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria which may result in changes to credit rating practices and policies.

The volatility in the global financial and capital markets may increase the cost of, and affect the timing of, issuance of long-term capital by the Corporation and its utilities in 2009. While the cost of borrowing is expected to increase, as new long-term debt is expected to be issued at higher rates due to an increase in credit spreads, the Corporation and its utilities expect to continue to have reasonable access to capital in the near to medium terms. Due to the regulated nature of the Corporation's utilities, increased borrowing costs are eligible to be recovered in future customer rates.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. The committed credit facility at the Corporation is available for interim financing of acquisitions and for general corporate purposes. The cost of renewed and extended credit facilities may also increase going forward; however, any increased interest expense and/or fees is not expected to have a material financial impact on the Corporation and its utilities in 2009 as the majority of the total committed credit facilities have maturities beyond 2009.

Further information about the Corporation's credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A and under "Liquidity Risk" in Note 26 to the 2008 Consolidated Financial Statements.

Weather and Seasonality: The physical assets of the Corporation and its subsidiaries are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power, exposure to climatic factors is addressed through the operation of a regulator-approved weather normalization reserve. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At TGI, a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing TGI to accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by customers.

At the Terasen Gas companies, weather has a significant impact on distribution volume, as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas-consumption patterns, the Terasen Gas companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. In Canada, cool summers may reduce air-conditioning demand while warm winters may reduce electric heating load. In the Caribbean, the impact of seasonal changes in weather on air-conditioning demand is less pronounced due to less variable climatic conditions that exist in the region. Significant fluctuations in weather-related demand for electricity could materially impact the operations, financial condition and results of operations of the electric utilities.

Despite preparation for severe weather, extraordinary conditions such as hurricanes and other natural disasters will always remain a risk to utilities. The Corporation uses a centralized insurance management function to create a higher level of insurance expertise and reduce its liability exposure.

The assets and earnings of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos are subject to hurricane risk. Similar to other Fortis utilities, these companies manage weather risks through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. In Belize, additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Under its new T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster, including a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant event.

Earnings from non-regulated generation assets are sensitive to rainfall levels but the geographic diversity of the Corporation's generation assets mitigates the risk associated with rainfall levels.

Commodity Price Risk: The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. The companies employ a number of tools to reduce exposure to natural gas price volatility. These tools include purchasing gas for storage and adopting hedging strategies to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive with electricity rates. The use of natural gas derivatives effectively fixes the price of natural gas purchases. Activities related to the hedging of gas prices are currently approved by the BCUC and gains or losses effectively accrue entirely to customers. The operation of BCUC-approved rate stabilization accounts to flow through in customer rates the commodity cost of natural gas serves to mitigate the effect on earnings of natural gas cost volatility.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affects the cost of fuel and purchased power. The risk is substantially mitigated through the utilities' ability to flow through to customers the cost of fuel and purchased power through basic rates and/or through the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel and purchased power will continue to exist in the future. An inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could materially affect the utilities' results of operations, financial position and cash flows.

Derivative Financial Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices through the use of derivative financial instruments. The derivative financial instruments, such as interest rate swap contracts, foreign exchange future contracts and natural gas commodity swaps and options, are used by the Corporation and its subsidiaries only to manage risk. The Corporation and its subsidiaries do not hold or issue derivative financial instruments for trading purposes. All derivative financial instruments must be measured at fair value. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates.

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00 = US$1.00. The Corporation has also designated all of its US$403 million corporately held US dollar-denominated long-term debt as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income. As at December 31, 2008, the Corporation had approximately US$119 million in foreign net investments remaining to be hedged.

Interest Rate Risk: Generally, allowed returns for regulated utilities in North America are exposed to changes in the general level of long-term interest rates. Earnings of such regulated utilities are exposed to changes in long-term interest rates associated with rate-setting mechanisms. The rate of return is affected either directly through automatic adjustment mechanisms or indirectly through regulatory determinations of what constitutes an appropriate rate of return on investment. Automatic adjustment mechanisms currently apply to the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power. Due to a decline in long-term Canada bond yields during 2008 and the operation of the automatic adjustment mechanisms, the allowed ROEs for TGI and FortisBC have been reset for 2009. The 2008 allowed ROEs for the Corporation's four largest utilities, TGI, FortisAlberta, FortisBC and Newfoundland Power, were 8.62 per cent, 8.75 per cent, 9.02 per cent and 8.95 per cent, respectively. Effective January 1, 2009, the allowed ROEs for TGI and FortisBC have decreased to 8.47 per cent and 8.87 per cent, respectively, while the allowed ROE for Newfoundland Power remains unchanged at 8.95 per cent. FortisAlberta is currently engaged in a Generic Cost of Capital Proceeding with its regulator to review, among other things, 2009 ROE calculations and capital structures for regulated gas, electric and pipeline utilities in Alberta. In the interim, as directed by its regulator, customer rates for 2009 for FortisAlberta have been set using the utility's 2007 allowed ROE of 8.51 per cent. The National Energy Board is also undertaking a review of existing ROE levels.

A continuation of current ROE adjustment mechanisms combined with declining long-term Canada bond yields, in an environment where the cost of capital is increasing, could materially affect the ability of the Corporation's utilities to earn reasonable ROEs, the absence of which could negatively impact the regulated utilities' financial condition, results of operations and cash flows.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with short-term borrowings and floating rate debt. However, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest rate expense resulting from fluctuations in interest rates associated with variable rate debt for recovery from, or refund to, customers in future rates. As described in the "Business Risk Management – Derivative Financial Instruments and Hedging" section of this MD&A, the Corporation and its subsidiaries may also enter into interest rate swap agreements from time to time to help reduce interest rate risk.

As at December 31, 2008, approximately 84 per cent of the Corporation's consolidated long-term debt facilities and capital lease obligations had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt at December 31, 2008.

Total Debt

As at December 31, 2008	*($ millions)*	*(%)*
Short-term borrowings	**410**	**7.4**
Utilized variable-rate credit facilities classified as long-term	**224**	**4.0**
Variable-rate long-term debt and capital lease obligations (including current portion)	**22**	**0.4**
Fixed-rate long-term debt and capital lease obligations (including current portion)	**4,878**	**88.2**
Total	**5,534**	**100.0**

A change in the level of interest rates could materially affect the measurement and recording of changes in the fair value of interest rate swaps. The impact of a material change in interest rates on the fair value measurement of the interest rate swaps outstanding as at December 31, 2008 is not expected to materially affect the Corporation's consolidated earnings and comprehensive income due to the low notional value of the interest rate swaps and their near-term maturities.

The nature and fair value of the interest rate swaps outstanding as at December 31, 2008 is provided in the "Financial Instruments" section of this MD&A. A sensitivity analysis of a change in interest rates as that change would have affected 2008 financial results is disclosed in Note 26 to the 2008 Consolidated Financial Statements.

It is estimated that a 6 cent, or 5 per cent, increase (decrease) in the US dollar-to-Canadian dollar exchange rate from the exchange rate of 1.22, as at December 31, 2008, would increase (decrease) basic earnings per common share of Fortis by 1 cent in 2009.

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar and Belizean dollar earnings' streams, where possible, through future US dollar borrowings and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. The Terasen Gas companies deal with high credit-quality institutions in accordance with established credit approval practices. Due to recent events in the capital markets, including significant government intervention in the banking system, the Terasen Gas companies have further limited the financial counterparties they transact with and have reduced available credit to, or taken additional security from, the physical off-system sales counterparties with which they transact. To date, the Terasen Gas companies have not experienced any counterparty defaults and they do not expect any counterparties to fail to meet their obligations; however, the credit quality of counterparties, as recent events have indicated, can change rapidly.

FortisAlberta is exposed to credit risk associated with sales to retailers. Significantly all of FortisAlberta's distribution-service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating. See also the "Business Risk Management – Economic Conditions" section of this MD&A.

Competitiveness of Natural Gas: In recent years, the price of natural gas has been only marginally lower than the comparable price for electricity for residential customers in British Columbia, especially on Vancouver Island. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future. If natural gas pricing becomes uncompetitive with electricity pricing or pricing for alternative energy sources, the ability of the Terasen Gas companies to add new customers could be impaired and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the cost of service of the Terasen Gas companies in rates charged to customers. The ability of the Terasen Gas companies to add new customers and increase sales volumes could also be affected by lower prices of other competitive energy sources, as some commercial and industrial customers have the ability to switch to an alternative fuel. See also the "Business Risk Management – Government of British Columbia's Energy Plan" and "Business Risk Management – Risks Related to TGVI" sections of this MD&A.

Natural Gas Supply: The Terasen Gas companies are dependent on a limited number of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas where the majority of the natural gas distribution customers of the Terasen Gas companies are located. Regional market prices have been higher from time to time than prices elsewhere in North America, as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia and the US Pacific Northwest. In addition, the Terasen Gas companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the Terasen Gas companies could experience outages, thereby affecting revenue and incurring costs to safely relight customers.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of Terasen, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees; however, only 61 per cent of the above utilities' total employees are members of such plans. The recent volatility in the global financial and capital markets is expected to affect the Corporation's consolidated future defined benefit pension funding requirements, as discussed in the "Liquidity and Capital Resources – Pension Funding" section of this MD&A. Future pension benefit obligations and related pension expense may also be affected. The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the accrued pension benefit obligation and related pension expense. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued pension benefit obligation. A discussion of the critical accounting estimates associated with defined benefit pension plans is provided in the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

There is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future. With the exception of Newfoundland Power and Terasen, the pension plan assets are valued at fair value. At Newfoundland Power and Terasen, the pension plan assets are valued using the market-related value as disclosed in Note 2 to the 2008 Consolidated Financial Statements. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed long-term return on the assets. This may cause material changes in future pension funding requirements from current estimates and material changes in future pension expense.

Market-driven changes impacting the discount rate, which is used to value the accrued pension benefit obligation as at the measurement date of each of the defined benefit pension plans, may result in material changes in future pension funding requirements from current estimates and material changes in future pension expense.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of pension expense, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation.

The above risks are mitigated as any increase or decrease in future pension funding requirements and/or pension expense at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. At the Terasen Gas companies and FortisBC, however, actual pension expense above or below the forecast pension expense approved for recovery in customer rates for the year is subject to deferral account treatment for recovery from, or refund to, customers in future rates, subject to regulatory approval. Also mitigating the above risks is the fact that the defined benefit pension plans at FortisAlberta and Newfoundland Power are closed to all new employees.

Risks Related to TGVI: TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service and to recover revenue deficiencies from prior years. Recovery of accumulated revenue deficiencies from prior years puts gas at a cost disadvantage relative to electricity. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") provides royalty revenues from the Government of British Columbia which currently cover approximately 20 per cent of the current cost of service. These revenues are due to expire at the end of 2011, after which time TGVI's customers will be required to absorb the full commodity cost of gas, all other costs of service and the recovery of any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining amount outstanding under non-interest bearing senior government loans, which is currently treated as a government contribution against rate base, will be required to be fully repaid. As at December 31, 2008, the balance outstanding under these loans was $61 million. As the debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates, making gas less competitive with electricity on Vancouver Island.

Government of British Columbia's Energy Plan: The Government of British Columbia released its Energy Plan in February 2007. The Energy Plan is a progression from the previous plan with a focus on environmental leadership, energy conservation and efficiency, and investing in innovation. The Energy Plan outlines various measures to address the challenges of global warming including that all electricity produced in British Columbia will be required to have zero net greenhouse gas emissions by 2016. The Energy Plan places a significant responsibility on British Columbians to conserve energy by requiring 50 per cent of British Columbia's incremental resource needs to be achieved through conservation by 2020. The Energy Plan emphasizes efficiency by requiring BC Hydro to eliminate electricity imports and become fully self-sufficient by 2016. The Energy Plan also states that 90 per cent of British Columbia's electricity will come from renewable sources and that British Columbia will become the first jurisdiction in North America to require 100 per cent carbon sequestration for any coal-fired electricity project. FortisBC and the Terasen Gas companies continue to assess the impacts and opportunities provided by the Energy Plan and will consider which policy actions they may support. Many of the principles of the Energy Plan were adopted when *Bill 15-2008, the Utilities Commission Amendment Act, 2008*, received Royal Assent by the Legislative Assembly of British Columbia on May 1, 2008. In addition, the *Carbon Tax Act*, which received Royal Assent by the Legislative Assembly of British Columbia on May 29, 2008, introduced a consumption tax on carbon-based fuels which impacts the competitiveness of natural gas versus non-carbon-based energy sources. The legislation did not, however, introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The future impact of the Government of British Columbia's Energy Plan and the recent legislation may have a material impact on the competitiveness of natural gas relative to other energy sources.

Environmental Risks: The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs could potentially arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines, or damages may become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental regulatory approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. During 2008, costs arising from environmental protection, compliance or damages were not material to the Corporation's consolidated results of operations, cash flows or financial position. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. As at December 31, 2008, there were no material environmental liabilities recorded in the Corporation's 2008 Consolidated Financial Statements and there were no material unrecorded environmental liabilities known to management. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators will agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could materially affect the results of operations, cash flows and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines or their enforcement or regulatory interpretation, could materially impact the results of operations, cash flows and financial position of the Corporation and its subsidiaries.

The Corporation's gas and electricity businesses are subject to inherent risks, including risk of fires and contamination of air, soil or water from hazardous substances. Risks associated with fire damage relate to the extent of forest and grassland cover, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire suppression costs, regeneration and timber value costs and third-party claims in connection with fires on lands on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the storage and handling of large volumes of fuel, the use and disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. The management of greenhouse gas emissions is the main environmental concern of the Corporation's regulated gas utilities, primarily due to recent changes to the Government of British Columbia's Energy Plan and related legislation as discussed above. Any changes in environmental laws, regulations or guidelines governing contamination could lead to significant increases in costs to the Corporation and its subsidiaries.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to electric and magnetic fields from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health hazard, litigation could result and the electric utilities could be required to pay damages and take mitigation measures on its facilities. The costs of litigation, damages awarded and mitigation measures, if not approved by regulators for recovery in customer rates, could materially impact the results of operations, cash flows and financial condition of the electric utilities.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by the insurance. For further information on insurance, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

The Corporation's utilities address environmental matters in their operations through the use of Environmental Management Systems ("EMS"). As part of their respective EMS, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor environmental performance.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authorities to recover the loss or liability through increased customer rates. However, there can be no assurance that regulatory authorities would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's and subsidiaries' business, results of operations and financial condition. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's and subsidiaries' business, results of operations and financial position.

It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements or that the insurance companies will meet their obligations to pay claims.

Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government and government agencies. The Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval, or if there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could materially affect the subsidiaries.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located within their municipal boundaries. Upon the termination of its franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric utility expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost less depreciation. Given the historical growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently in progress with FortisAlberta pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could materially affect the financial condition and results of operations of FortisAlberta.

Market Energy Sales Prices: The Corporation's primary exposure to changes in market energy sales prices at its electricity operations has related to its non-regulated energy sales in Ontario, where energy is sold to the Independent Electricity System Operator at market prices. Non-regulated energy sales in Ontario largely relate to a power-for-water exchange agreement, known as the Niagara Exchange Agreement, associated with the Rankine hydroelectric generating station. In accordance with this agreement, FortisOntario's water entitlement on the Niagara River will expire on April 30, 2009 and, as a result, the Corporation's exposure to market price fluctuations in Ontario will be substantially reduced and earnings related to the Niagara Exchange Agreement will cease after that date. During 2008, earnings' contribution associated with the Niagara Exchange Agreement was approximately $16 million. The Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. All energy produced by these assets is sold to the National Grid at market prices. Energy from the Corporation's non-regulated generation assets in Belize, central Newfoundland and British Columbia is sold under medium- and long-term fixed-price contracts.

Transition to International Financial Reporting Standards: Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). IFRS will require increased financial statement disclosure compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by Fortis. The Corporation is currently assessing the impact a conversion to IFRS would have on its future financial reporting. In the event regulated assets and liabilities are not permissible under IFRS, this could result in increased volatility in the Corporation's consolidated earnings and balance sheet from that reported under Canadian GAAP. Information on the Corporation's IFRS conversion project is provided in the "Future Accounting Changes" section of this MD&A.

Changes in Tax Legislation: The Government of Canada has enacted legislative changes that will challenge the continuation of the tax-deferred status of offshore earnings derived from foreign affiliates. The legislative changes will require that the governments of these tax-free jurisdictions enter into tax treaties or other comprehensive tax information-exchange agreements ("TIEAs") with Canada before 2015. If the jurisdictions are unable to establish these treaties or agreements, the earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis after 2014 as if they were in Canada. Conversely, if treaties or agreements can be reached, the earnings from these jurisdictions will be able to be repatriated to Canada tax free. In the event that the offshore earnings become taxable, earnings' contribution from the Corporation's Caribbean Regulated Electric utilities and BECOL will decrease.

On December 10, 2008, the Advisory Panel on Canada's System of International Taxation (the "Advisory Panel") provided its recommendations to the Minister of Finance of the Government of Canada in its final report, "Enhancing Canada's International Tax Advantage". The Advisory Panel was formed by the Government of Canada in November 2007 to provide recommendations to improve Canada's international tax policy respecting foreign investment by Canadian businesses and investment in Canada by foreign businesses. The Advisory Panel's recommendations seek to improve Canada's tax system regarding outbound and inbound business investment, non-resident withholding taxes, and administration, compliance and legislative processes. Specifically, the Advisory Panel recommended that the Government of Canada pursue TIEAs on a government-to-government basis without resorting to accrual taxation for foreign active business income if a TIEA is not obtained. The Advisory Panel also recommended that the Government of Canada broaden the existing exemption system to cover all foreign active business income earned by foreign affiliates.

On January 27, 2009, the Government of Canada introduced its 2009 Budget. In the budget documents, the Government of Canada indicated that it is studying the Advisory Panel's report and will provide a response in due course on which consultations will be held. The Government of Canada also indicated that it will consider the Advisory Panel's recommendations relating to foreign affiliates before proceeding with the remaining foreign affiliate measures announced in February 2004, as modified to take into account consultations and deliberations since their release.

Any future changes in other tax legislation could also materially affect the Corporation's consolidated earnings.

First Nations' Lands: The Terasen Gas companies and FortisBC provide service to customers on First Nations' lands and maintain gas and electric distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Terasen Gas companies and FortisBC is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as the Terasen Gas companies and FortisBC. However, there can be no certainty that the settlement process will not materially affect the business of the Terasen Gas companies and FortisBC. In addition, FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by FortisAlberta's predecessor, TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Indian and Northern Affairs Canada and the individual Band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-usage agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material effect on the business of FortisAlberta.

Labour Relations: Approximately 60 per cent of the employees of the Corporation's subsidiaries are members of labour unions or associations which have entered into collective bargaining agreements with the subsidiaries. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the businesses carried out by the subsidiaries. The Corporation considers the relationships of its subsidiaries with its labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material effect on the results of operations, cash flow and earnings of the utilities.

The collective agreement between FortisBC and the International Brotherhood of Electrical Workers ("IBEW"), Local 213, expired on January 31, 2009. A new four-year collective agreement was ratified by the union in February 2009.

In September 2008, two collective agreements governing Newfoundland Power's unionized employees represented by IBEW, Local 1620, expired. In February 2009, one of the groups represented by IBEW, Local 1620, ratified a new collective agreement. This new collective agreement will be effective October 1, 2008 and will expire on September 30, 2011. The second collective agreement is subject to a conciliation process which began in March 2009.

In December 2008, the collective agreement governing Maritime Electric's unionized employees represented by IBEW, Local 1432, expired. Maritime Electric and IBEW are currently negotiating a new collective agreement.

Human Resources: The ability of Fortis to deliver superior operating performance in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and an increasingly competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program over the next several years will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

Changes in Accounting Standards

The nature of, and impact on Fortis of, adopting the new Canadian Institute of Chartered Accountants ("CICA") accounting standards for Inventories, Capital Disclosures, and Disclosure and Presentation of Financial Instruments, effective January 1, 2008, are described in detail in Notes 5, 24, 25 and 26 to the 2008 Consolidated Financial Statements. The most significant impacts of adopting the new standards were: (i) the reclassification of $26 million of inventories to utility capital assets from inventories on the consolidated balance sheet as at December 31, 2007; (ii) additional disclosures about the Corporation's capital, including quantitative and qualitative information regarding the Corporation's objectives, policies and processes for managing capital; and (iii) additional disclosures of both qualitative and quantitative information that enable users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed. The adoption of the accounting standards did not have a material impact on the Corporation's 2008 Consolidated Financial Statements.

Future Accounting Changes

IFRS: In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an IFRS Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011.

On June 27, 2008, the Canadian Securities Administrators ("CSA") issued Staff Notice 52-321, *Early Adoption of IFRS* which indicated that the CSA would be prepared to grant an exemption to allow Canadian financial statement issuers to adopt IFRS early on a case-by-case basis, provided that they could demonstrate that they met certain conditions. Fortis is not planning to early adopt IFRS.

The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010 and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section – *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued, but is not yet effective and that the entity has not applied, not be applied with respect to the IFRS Omnibus Exposure Draft.

Fortis is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Fortis does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required as well as systems changes that may be necessary to gather and process the required information.

Fortis commenced its IFRS conversion project in 2007 and has established a formal project governance structure which includes the audit committees, senior management and project teams from each of the Corporation's subsidiaries. Overall project governance, management and support are coordinated by Fortis Inc. Regular reporting occurs to the Audit Committee of the Board of Directors of Fortis and of the subsidiaries, where appropriate. An external expert advisor has been engaged to assist in the IFRS conversion project.

The Corporation's IFRS conversion project consists of three phases: Scoping and Diagnostics, Analysis and Development, and Implementation and Review.

Phase One: Scoping and Diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, has been completed. The resulting identified areas of accounting difference of highest potential impact to Fortis, based on existing IFRS, are rate-regulated accounting; property, plant and equipment; investment property; provisions and contingent liabilities; employee benefits; impairment of assets; income taxes; business combinations; and initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS*.

Phase Two: Analysis and Development is nearing completion and involves detailed diagnostics and evaluation of the financial reporting impacts of various options and alternative methodologies provided for under IFRS; identification and design of operational and financial business processes; initial staff and audit committee training; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application upon transition to IFRS; summarization of 2011 IFRS disclosure requirements; and development of required solutions to address identified issues.

The Corporation has completed a preliminary assessment of the impacts of adopting IFRS; however, a final assessment cannot be completed at this time pending the outcome of the project on rate-regulated activities that was recently added to the IASB's technical agenda.

It is anticipated that the adoption of IFRS will have an impact on information systems requirements. Each of the Corporation's subsidiaries is assessing the need for system upgrades or modifications to ensure an efficient conversion to IFRS. As part of Phase Two, information systems plans are being prepared for implementation in Phase Three. The extent of the impact on each of the subsidiary's information systems is not reasonably determinable at this time.

During 2008, several regulatory authorities with jurisdiction over the Corporation's regulated utilities began their own IFRS projects to determine the nature of any changes that should be made in regulatory accounting requirements in response to IFRS. The Corporation's regulated utilities have worked and will continue to work with their respective regulatory authorities to identify transitional issues and suggest how those issues might be addressed.

Phase Three: Implementation and Review, expected to commence mid-year 2009, will involve the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and further training programs across the Corporation's finance and other affected areas, as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS in business processes and Audit Committee approval of IFRS-compliant financial statements.

Fortis will continue to review all proposed and continuing projects of the IASB, particularly the project on rate-regulated activities that was recently added to the IASB's technical agenda and proposed amendments to IFRS 1 for entities with operations subject to rate regulation, and will participate in any related processes as appropriate.

Rate-Regulated Operations: Effective January 1, 2009, the AcSB amended: (i) CICA Handbook Section 1100, *Generally Accepted Accounting Principles* removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; and (ii) Section 3465, *Income Taxes* to require the recognition of future income tax liabilities and assets as well as offsetting regulatory assets and liabilities by entities subject to rate regulation.

Effective January 1, 2009, the impact on Fortis of the amendment to Section 3465, *Income Taxes* will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the cash taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes* as at December 31, 2008, would have been an increase in future income tax assets and future income tax liabilities of $24 million and $497 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of $24 million and $497 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates and the separate disclosure of future income tax assets and liabilities that are currently not recognized.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Corporation must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. The assets and liabilities arising from rate regulation, as described in Note 4 to the 2008 Consolidated Financial Statements, do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Corporation to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. The Corporation's regulatory assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Corporation's consolidated financial statements if it had adopted the removal of the temporary exemption in Section 1100 for the year ended December 31, 2008. Fortis is continuing to assess any additional implications on its financial reporting related to accounting for rate-regulated operations.

Goodwill and Intangible Assets: Effective January 1, 2009, the Corporation will adopt the new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. This Section, which replaces Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The currently estimated effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3064 as at December 31, 2008, would have been an increase in intangible assets of $234 million, a reduction in utility capital assets of $232 million and a reduction in deferred charges and other assets of $2 million for the reclassification of the net book value of land and transmission rights, computer software costs and franchise costs. The Corporation is continuing to assess and quantify any additional financial reporting impacts from adopting this standard.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities: Effective January 1, 2009, the Corporation will adopt the new Emerging Issues Committee ("EIC")-173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*, which was issued on January 20, 2009. EIC-173 requires that the Corporation's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. As at December 31, 2008, only the Corporation's derivative financial instruments were recorded at fair value, the majority of which were out-of-the-money and recorded as a liability. The Corporation is continuing to assess any additional financial reporting impacts of adopting this EIC.

Financial Instruments

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the Corporation's consolidated balance sheets approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments. The fair value of long-term debt is calculated by using quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

An increase in credit risk and spreads as a result of the volatility experienced in the financial and capital markets has resulted in lower fair values for the Corporation's consolidated long-term debt and preference shares as at December 31, 2008 compared to December 31, 2007.

The carrying and fair values of the Corporation's consolidated long-term debt and preference shares as at December 31 were as follows.

Financial Instruments[(1)]

As at December 31	**2008**		2007	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion[(1)]	**5,088**	**4,927**	5,023	5,635
Preference shares, classified as debt[(2)]	**320**	**329**	320	346

(1) Carrying value as at December 31, 2008 is net of unamortized deferred financing costs of $34 million (December 31, 2007 – $33 million).

(2) Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's $347 million of preference shares classified as equity was $268 million at December 31, 2008 (December 31, 2007 – carrying value $122 million; fair value $107 million).

The Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes.

The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

Derivative Financial Instruments

As at December 31	2008				2007	
Asset (Liability)	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *($ millions)*	**Estimated Fair Value** *($ millions)*	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Interest Rate Swaps	**1 to 2**	**2**	**–**	**–**	–	–
Foreign Exchange Forward Contract	**<3**	**1**	**7**	**7**	–	–
Natural Gas Derivatives:						
Swaps and Options	**Up to 3**	**228**	**(84)**	**(84)**	(79)	(79)
Gas Purchase Contract Premiums	**Up to 3**	**74**	**(8)**	**(8)**	5	5

The interest rate swaps are held by Fortis Properties and are designated as hedges of the cash flow risk related to floating-rate long-term debt and mature in July 2009 and October 2010. The effective portion of changes in the fair value of the interest rate swaps at Fortis Properties is recorded in other comprehensive income. During 2008, the interest rate swaps of the Terasen Gas companies matured.

The foreign exchange forward contract is held by TGVI and is designated as a hedge of the cash flow risk related to approximately US$55 million required to be paid under a contract for the construction of an LNG storage facility.

The natural gas derivatives are used to fix the effective purchase price of natural gas as the majority of the natural gas supply contracts have floating, rather than fixed, prices. At the Terasen Gas companies, changes in the fair value of interest rate swaps, the foreign exchange forward contract and natural gas derivatives are deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. The fair values of the natural gas derivatives were recorded in accounts payable as at December 31, 2008 (December 31, 2007 – accounts payable and accounts receivable).

The interest rate swaps are valued at the present value of future cash flows based on published forward future interest rate curves. The foreign exchange forward contract is valued using the present value of future cash flows based on published forward future foreign exchange market rate curves. The fair values of the natural gas derivatives reflect the estimated amounts, based on published forward curves, the Terasen Gas companies would have to receive or pay if forced to settle all outstanding contracts at the balance sheet date.

The fair value of the Corporation's financial instruments, including derivatives, reflects a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

Critical Accounting Estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authorities. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recorded based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known. As at December 31, 2008, Fortis recorded $360 million in current and long-term regulatory assets (December 31, 2007 – $312 million) and $446 million in current and long-term regulatory liabilities (December 31, 2007 – $392 million). The increase in regulatory assets year over year was primarily due to amounts deferred in FortisAlberta's AESO charges deferral account in 2008 and the deferral of an increase in the cost of fuel and power at Maritime Electric and Caribbean Utilities. The increase in regulatory liabilities year over year was largely associated with BCUC-approved rate stabilization accounts at the Terasen Gas companies. The nature of the Corporation's regulatory assets and liabilities is described in Note 4 to the 2008 Consolidated Financial Statements.

Capital Asset Amortization: Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2008, the Corporation's consolidated utility capital assets and income producing properties were approximately $7.9 billion, or approximately 71 per cent of total consolidated assets, compared to consolidated utility capital assets and income producing properties of $7.3 billion, or approximately 71 per cent of total consolidated assets, as at December 31, 2007. The increase in capital assets was primarily associated with capital expenditures, which totalled $904 million in 2008. Amortization expense for 2008 was $348 million compared to $273 million for 2007. Changes in amortization rates may have a significant impact on the Corporation's consolidated amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate amortization rates are approved by the respective regulatory authorities. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric include an amount for regulatory purposes to provide for future asset removal and site restoration costs, net of salvage proceeds, over the life of the assets. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the provision when incurred. The accrual of the estimated costs is included with amortization expense and the provision balance is recorded as a long-term regulatory liability. The estimate of the future asset removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2008 was $337 million (December 31, 2007 – $319 million). The amount of future asset removal and site restoration costs provided for and reported in amortization expense during 2008 was $35 million (2007 – $33 million).

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over or under amortization, as a result of actual experience differing from that expected and provided for in previous amortization rates, is generally reflected in future amortization rates and amortization expense, when the differences are refunded or collected in customer rates as approved by the regulator. Changes in regulator-approved amortization rates at FortisAlberta and Newfoundland Power during 2008 did not have a material impact on consolidated amortization expense.

Capitalized Overhead: As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity and, commencing in May 2008, Caribbean Utilities capitalize overhead costs which are not directly attributable to specific capital assets but which relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the respective regulators. In 2008, GEC totalled $57 million (2007 – $42 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recorded as operating expenses versus utility capital assets.

Goodwill Impairment Assessments: Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost, less any previous amortization and write-down for impairment. The Corporation is required to perform an annual impairment test and at such time any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. In July of each year, the Corporation reviews for impairment of goodwill and updates its review as at year end. To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. Fair market value is determined using net present value financial models and management's assumption of future profitability of the reporting units. There was no impairment provision required on $1.6 billion of goodwill recorded on the Corporation's balance sheet as at December 31, 2008. For a discussion of the nature of the change in goodwill during 2008, refer to the "Consolidated Financial Position" section of this MD&A.

Employee Future Benefits: The Corporation's and subsidiaries' defined benefit pension plans and other post-employment benefit ("OPEB") plans are subject to judgments utilized in the actuarial determination of the expense and related obligation. The main assumptions utilized by management in determining pension expense and obligations are the discount rate for the accrued pension benefit obligation and the expected long-term rate of return on plan assets.

The assumed long-term rates of return on the defined benefit pension plan assets, for the purpose of estimating pension expense for 2009, range from 6.75 per cent to 7.25 per cent for the larger defined benefit pension plans. These rates compare to assumed long-term rates of return used in 2008 that ranged from 6.50 per cent to 7.50 per cent. The defined benefit pension plan assets experienced total negative returns during 2008 of approximately $92 million compared to expected positive returns of $49 million. The assumed expected long-term rates of return on pension plan assets fall within the range of expected returns as provided by the actuaries' internal models.

The assumed discount rates used to measure the accrued pension benefit obligations on the applicable measurement dates in 2008 and to determine pension expense for 2009 ranged from 6.00 per cent to 7.50 per cent for the larger defined benefit plans. These rates compare to assumed discount rates used to measure the accrued pension benefit obligations in 2007 and determine pension expense for 2008 that ranged from 5.25 per cent to 5.60 per cent. The discount rates increased as a result of the impact of increased credit risk spreads on investment-grade corporate bonds due to volatility in the capital markets. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year.

As the measurement date for FortisAlberta, FortisBC and FortisOntario's defined benefit pension plans is September 30, 2008, the further impact on credit risk spreads of capital market volatility that continued through the remainder of 2008 was not reflected in the discount rates assumed by these utilities as at September 30, 2008, nor was the further erosion of capital market value reflected in the fair value of the pension plan assets measured as at September 30, 2008.

Fortis expects no material increase in its consolidated pension expense for 2009 related to its defined benefit pension plans. The amortization of 2008 losses associated with the pension plan assets is expected to be largely offset by the impact of higher assumed discount rates. The impact of the decline in pension plan assets in 2008, as it relates to 2009 pension expense, is being mitigated by the use of the market-value related method for valuing pension assets at the Terasen Gas companies and Newfoundland Power.

Consolidated defined benefit pension expense and pension funding obligations for 2009 may be affected, however, by the outcome of December 31, 2008 actuarial valuations which, for Newfoundland Power, the Corporation and for one of the defined benefit pension plans at Terasen, are expected to be completed in 2009.

The following table provides the sensitivities associated with a 100 basis point move in the expected long-term rate of return on pension plan assets and the discount rate on 2008 net defined benefit pension expense, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2008

Increase (decrease)	Net benefit expense		Accrued benefit asset		Accrued benefit liability		Benefit obligation	
($ millions)	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities
Impact of increasing the rate of return assumption by 100 basis points	(3)	(4)	3	4	–	–	–	–
Impact of decreasing the rate of return assumption by 100 basis points	3	4	(3)	(4)	–	–	–	–
Impact of increasing the discount rate assumption by 100 basis points	–	(3)	(1)	3	(1)	–	(19)	(38)
Impact of decreasing the discount rate assumption by 100 basis points	4	6	(3)	(5)	1	–	21	46

Other assumptions applied in measuring defined benefit pension expense and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the expense and related obligation. The assumptions described above, except for the assumptions of the expected long-term rate of return on pension plan assets and average rate of compensation increase, along with health care cost trends, were also utilized by management in determining OPEB plan expense and obligations.

As approved by the respective regulators, FortisAlberta and Newfoundland Power record the cost of defined benefit pension and/or OPEB plan benefits on a cash basis, whereby differences between the cash payments made during the year and the expense incurred during the year are deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions cause changes in regulatory assets and liabilities for these companies and do not affect earnings. As disclosed in the "Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements" section of this MD&A, the Terasen Gas companies and FortisBC have regulator-approved mechanisms to defer variations in pension expense from forecast pension expense, used to set customer rates, as a regulatory asset or regulatory liability.

As at December 31, 2008, the Corporation had a consolidated accrued benefit asset of $133 million (December 31, 2007 – $120 million) and a consolidated accrued benefit liability of $168 million (December 31, 2007 – $150 million). During 2008, the Corporation recorded consolidated net benefit expense of $27 million (2007 – $26 million).

Asset-Retirement Obligations: The measurement of fair value of asset-retirement obligations ("AROs") requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights of way at the end of the life of the systems and the remediation of certain land, there were no amounts recorded as at December 31, 2008 and 2007. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and distribution and transmission assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned, or the applicable licences, permits, agreements or leases are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

Revenue Recognition: All of the Corporation's regulated utilities, except for Belize Electricity, recognize revenue on an accrual basis. As required by the PUC, Belize Electricity recognizes electricity revenue on a billed basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish gas and electricity consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authorities. The development of the gas and electricity sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2008, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $365 million (December 31, 2007 – $309 million) on annual consolidated revenue of approximately $3.9 billion (2007 – $2.7 billion).

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to $7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset. The matter is currently under appeal to the Supreme Court of British Columbia.

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from CRA for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the 2008 Consolidated Financial Statements. Terasen has begun the appeal process associated with the assessments.

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGVI seeking damages for alleged past overpayments and a future reduction in tolls. The Statement of Claim does not quantify damages and, as such, the Company cannot determine the amount of the claim at this time. It is the Company's view that the claim is without merit. No amount, therefore, has been accrued in the 2008 Consolidated Financial Statements.

FortisBC

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by a private landowner in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2008 Consolidated Financial Statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of the Point Lepreau Nuclear Generating Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation which confirmed the April 2006 reassessments. The Company will file an Appeal to the Tax Court of Canada.

Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $13 million in taxes and accrued interest. As at December 31, 2008, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

FortisUS Energy

During 2008, a statutory discontinuance and final release of FortisUS Energy was issued in relation to legal proceedings initiated by the Village of Philadelphia (the "Village"), New York. The Village had claimed that FortisUS Energy should honour a series of current and future payments set out in an agreement between the Village and a former owner of the hydroelectric site, located in the municipality of the Village, now owned by FortisUS Energy, totalling approximately $9 million (US$7 million). There was no impact on the 2008 Consolidated Financial Statements as a result of the settlement of these legal proceedings.

Exploits Partnership

On December 16, 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of the Newfoundland assets of Abitibi-Consolidated. Prior to that date, Abitibi-Consolidated announced the closure of its Grand Falls-Windsor, Newfoundland newsprint mill, effective March 31, 2009. The hydroelectric generating facility assets of the Exploits Partnership were included as part of the expropriation legislation. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The financial statements of the Exploits Partnership are consolidated in the financial statements of Fortis. The Exploits Partnership has a $61 million term loan, which is non-recourse to Fortis, with several lenders which is secured by the assets of the Exploits Partnership.

Discussions are ongoing with Exploits Partnership's lenders with respect to the above matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated. Pending resolution of these matters, the deferred financing costs of $2 million and utility capital assets of $61 million related to the Exploits Partnership have been reclassified to deferred charges and other assets and the $61 million term loan has been reclassified as current on the consolidated balance sheet of Fortis as at December 31, 2008.

Selected Annual Financial Information

The following table sets forth the annual financial information for the years ended December 31, 2008, 2007 and 2006. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2008**	2007(1)	2006
Revenue and equity income	**3,903**	2,718	1,472
Net earnings	**259**	199	149
Net earnings applicable to common shares	**245**	193	147
Total assets	**11,178**	10,273	5,441
Long-term debt and capital lease obligations (net of current portion)	**4,884**	4,623	2,558
Preference shares(2)(3)	**667**	442	442
Common shareholders' equity	**3,046**	2,601	1,276
Basic earnings per common share	**1.56**	1.40	1.42
Diluted earnings per common share	**1.52**	1.32	1.37
Dividends declared per common share	**1.01**	0.88	0.70
Dividends declared per First Preference Share, Series C	**1.3625**	1.3625	1.3625
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series F(4)	**1.2250**	1.2250	0.5211
Dividends declared per First Preference Share, Series G(3)	**1.0184**	–	–

(1) Financial results for 2007 were significantly impacted by the acquisition of Terasen on May 17, 2007.

(2) Includes preference shares classified as equity and long-term debt

(3) A total of 9.2 million First Preference Shares, Series G were issued on May 23, 2008 and June 4, 2008 at $25.00 per share for net after-tax proceeds of $225 million and are entitled to receive cumulative dividends in the amount of $1.3125 per share per annum.

(4) 5 million First Preference Shares, Series F were issued on September 28, 2006 at $25.00 per share for net after-tax proceeds of $122 million and are entitled to receive cumulative dividends in the amount of $1.2250 per share per annum.

2008/2007 – Revenue increased 43.6 per cent over 2007. The increase was driven by contributions from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007. Net earnings applicable to common shares grew 26.9 per cent over 2007. The increase in earnings was primarily due to earnings' contributions from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007, rate base growth and higher allowed ROEs at the Corporation's Canadian Regulated Utilities, and increased non-regulated hydroelectric production due to higher rainfall. The increase was tempered by a one-time $13 million loss related to a June 2008 regulatory rate decision at Belize Electricity and lower corporate tax recoveries at FortisAlberta. The growth in total assets and increase in long-term debt in 2008 was primarily due to the Corporation's continued investment in energy systems, driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies, combined with the impact of foreign exchange associated with translation of foreign currency-denominated assets and liabilities. The Corporation issued $230 million preference shares in 2008, the net proceeds of which were primarily used to repay borrowings under the Corporation's committed credit facility, to fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes. The Corporation also issued $300 million common shares in 2008, the net proceeds of which were used to repay short-term debt primarily incurred to retire $200 million of maturing debt at Terasen, and for general corporate purposes. Basic earnings per common share increased 11.4 per cent from 2007, primarily due to growth in earnings.

2007/2006 – Revenue, including equity income, increased 84.6 per cent over 2006. The increase was driven by contributions from the Terasen Gas companies, from the date of acquisition, and the impact of consolidating the Corporation's approximate 54 per cent controlling ownership in Caribbean Utilities during 2007 compared to recording the Corporation's 37 per cent interest in Caribbean Utilities during 2006 on an equity basis. Net earnings applicable to common shares grew 31.3 per cent over 2006, attributable to the acquisition of Terasen in May 2007, the first full year of ownership of Fortis Turks and Caicos, significant investment in electrical infrastructure at FortisAlberta and FortisBC, stronger performance at Fortis Properties and lower effective corporate taxes. The growth in total assets and increase in long-term debt in 2007 was driven by assets acquired and debt assumed upon the acquisition of Terasen in May 2007. The remaining increase in assets and long-term debt was primarily due to the Corporation's continued investment in energy systems, driven by the capital expenditure programs at FortisAlberta and FortisBC and the acquisition of the Delta Regina, partially offset by the impact of foreign exchange associated with translation of foreign currency-denominated assets and liabilities. Common shareholders' equity more than doubled during 2007, driven by the issuance of approximately $1.15 billion in common equity required to fund a significant portion of the net cash purchase price of Terasen. Basic earnings per common share decreased 1.4 per cent from 2006. Basic earnings per common share in 2007 were diluted by the common shares issued to fund the acquisition of Terasen and seasonality of earnings at the Terasen Gas companies.

Fourth Quarter Results

The following tables set forth unaudited financial information for the quarters ended December 31, 2008 and 2007. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. A discussion of the financial results for the fourth quarter of 2008 is also contained in the Corporation's fourth quarter 2008 media release, dated and filed on SEDAR at www.sedar.com on February 5, 2009, which is incorporated by reference in this MD&A.

Summary of Volumes, Sales and Revenue

Fourth Quarters Ended December 31 *(Unaudited)*	Gas Volumes *(TJ)* Energy and Electricity Sales *(GWh)*			Revenue *($ millions)*		
	2008	2007	Variance	**2008**	2007	Variance
Regulated Gas Utilities – Canadian *(TJ)*						
Terasen Gas Companies	**66,816**	69,108	(2,292)	**606**	548	58
Regulated Electric Utilities – Canadian *(GWh)*						
FortisAlberta	**4,068**	4,002	66	**78**	68	10
FortisBC	**842**	839	3	**66**	61	5
Newfoundland Power	**1,412**	1,384	28	**139**	132	7
Other Canadian	**543**	554	(11)	**65**	66	(1)
	6,865	6,779	86	**348**	327	21
Regulated Electric Utilities – Caribbean *(GWh)*	**361**	272	89	**159**	76	83
Non-Regulated – Fortis Generation *(GWh)*	**312**	303	9	**20**	19	1
Non-Regulated – Fortis Properties				**52**	50	2
Corporate and Other				**7**	6	1
Inter-Segment Eliminations				**(10)**	(8)	(2)
Total				**1,182**	1,018	164

Gas Volumes: Gas volumes at the Terasen Gas companies decreased quarter over quarter, primarily due to lower transportation volumes to customers sourcing their own gas supplies, partially offset by higher sales volumes to residential customers as a result of increased consumption due to cooler weather compared to the same period for the previous year.

Energy and Electricity Sales: Increased energy and electricity sales at the Corporation's regulated electric utilities quarter over quarter were driven by: (i) two additional months of contribution from Caribbean Utilities related to a change in the utility's fiscal year end; (ii) an increase at FortisAlberta mainly due to customer growth; and (iii) an increase at Newfoundland Power primarily due to the combined impact of customer growth and higher average consumption. The increases were partially offset by decreased sales at Other Canadian Electric Utilities, driven by the impact of the shut down of operations of certain industrial customers in Ontario and lower average consumption in Ontario.

The increase in energy sales at Non-Regulated – Fortis Generation was mainly due to higher production in central Newfoundland and Upper New York State. Higher production was mainly the result of higher rainfall.

Revenue: Revenue for the fourth quarter of 2008 was $164 million higher than the same quarter in 2007. The increase was driven by the Terasen Gas companies and the Corporation's Regulated Electric Utilities. Revenue at the Terasen Gas companies increased quarter over quarter mainly due to higher commodity cost of gas charged to customers, increased residential consumption and an increase in customer gas distribution rates effective January 1, 2008, reflecting a higher allowed ROE for 2008. Increased revenue at Regulated Electric Utilities – Canadian quarter over quarter was mainly due to customer rate increases, which included the impact of higher allowed ROEs for 2008 and customer growth. Revenue at Regulated Electric Utilities – Caribbean increased quarter over quarter primarily due to two additional months of revenue contribution from Caribbean Utilities, an approximate $30 million favourable impact of foreign exchange associated with the translation of foreign currency-denominated revenue, due to the weakening of the Canadian dollar against the US dollar quarter over quarter, and the flow through to customers of higher energy supply costs.

Summary of Net Earnings Applicable to Common Shares

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2008**	2007	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies	**47**	52	(5)
Regulated Electric Utilities – Canadian			
FortisAlberta	**11**	6	5
FortisBC	**7**	7	–
Newfoundland Power	**8**	9	(1)
Other Canadian	**3**	3	–
	29	25	4
Regulated Electric Utilities – Caribbean	**8**	9	(1)
Non-Regulated – Fortis Generation	**8**	7	1
Non-Regulated – Fortis Properties	**4**	8	(4)
Corporate and Other	**(20)**	(22)	2
Net Earnings Applicable to Common Shares	**76**	79	(3)

Earnings: Earnings for the fourth quarter of 2008 were $76 million or $3 million lower than $79 million for the same quarter in 2007. Fourth quarter results for 2007 were favourably impacted by one-time items totalling approximately $13 million related to: (i) the sale of surplus land at TGI; (ii) the reduction of future income tax liability balances at Fortis Properties related to lower enacted corporate income tax rates; and (iii) an interconnection agreement-related refund at FortisOntario. Excluding these one-time items, earnings were $10 million higher quarter over quarter. The increase was driven by stronger performance and lower corporate taxes at FortisAlberta, lower corporate expenses and $1 million of additional earnings from Caribbean Utilities related to a change in the utility's fiscal year end. The increase was partially offset by the impact of: (i) a lower allowed ROA at Belize Electricity, effective July 1, 2008; (ii) an approximate $1 million loss of revenue at Fortis Turks and Caicos related to Hurricane Ike; and (iii) an approximate $2 million reduction in fourth quarter 2008 earnings at Newfoundland Power associated with a shift in the quarterly distribution of the utility's annual purchased power expense. Newfoundland Power's annual earnings were not affected by the shift in the quarterly distribution of annual purchased power expense.

Summary of Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2008**	2007	Variance
Cash, Beginning of Period	**68**	51	17
Cash Provided By (Used In)			
Operating Activities	**214**	152	62
Investing Activities	**(277)**	(234)	(43)
Financing Activities	**58**	89	(31)
Foreign Currency Impact on Cash Balances	**3**	–	3
Cash, End of Period	**66**	58	8

Cash flow provided from operating activities, after working capital adjustments, increased $62 million quarter over quarter. The increase was mainly due to favourable working capital changes at the Terasen Gas companies related to the impact of cooler weather and higher commodity natural gas costs charged to customers during the fourth quarter of 2008 compared to the fourth quarter of 2007. The increase was partially offset by lower cash from operating activities at FortisAlberta. However, during the fourth quarter of 2007, FortisAlberta received cash from the sale of amounts in its 2007 AESO charges deferral account.

Cash used in investing activities increased $43 million quarter over quarter, reflecting higher utility capital expenditures and the acquisition of the Fairmount Newfoundland hotel in November 2008.

Cash provided from financing activities was $31 million lower quarter over quarter. Increased cash associated with the $300 million common share issue in the fourth quarter of 2008 was more than offset by the impact of a net decrease in debt during the fourth quarter of 2008 compared to a net increase in debt during the same quarter for the previous year.

Quarterly Results

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2007 through December 31, 2008. The quarterly information has been prepared in Canadian dollars and obtained from the Corporation's interim unaudited consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results

(Unaudited)

Quarter Ended	Revenue *($ millions)*	Net Earnings Applicable to Common Shares *($ millions)*	Earnings per Common Share Basic *($)*	Earnings per Common Share Diluted *($)*
December 31, 2008	1,182	76	0.48	0.46
September 30, 2008	727	49	0.31	0.31
June 30, 2008	848	29	0.19	0.18
March 31, 2008	1,146	91	0.58	0.55
December 31, 2007	1,018	79	0.51	0.49
September 30, 2007	651	31	0.20	0.20
June 30, 2007	566	41	0.31	0.27
March 31, 2007	483	42	0.38	0.35

A summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Given the diversified group of companies, seasonality may vary. Financial results for the fourth quarter of 2008 include two additional months of contribution from Caribbean Utilities resulting from a change in the utility's fiscal year end. Financial results from May 17, 2007 were impacted by the acquisition of Terasen.

Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters. Financial results for the second quarter of 2008 reflected the $13 million unfavourable impact to Fortis of a charge recorded at Belize Electricity as a result of the June 2008 regulatory rate decision. Due to a shift in the quarterly distribution of annual purchased power expense at Newfoundland Power, the Company's earnings in 2008 were lower in the first and fourth quarters and higher in the second and third quarters compared to the same periods in 2007. Newfoundland Power's annual earnings were not affected by the shift in the quarterly distribution of annual purchased power expense. Financial results from August 1, 2007 were impacted by the acquisition of the Delta Regina in Saskatchewan.

December 2008/December 2007 – Net earnings applicable to common shares were $76 million, or $0.48 per common share, for the fourth quarter of 2008, compared to earnings of $79 million, or $0.51 per common share, for the fourth quarter of 2007. A discussion on the variances between the financial results for the fourth quarter of 2008 and the fourth quarter of 2007 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2008/September 2007 – Net earnings applicable to common shares were $49 million, or $0.31 per common share, for the third quarter of 2008 compared to earnings of $31 million, or $0.20 per common share, for the third quarter of 2007. Third quarter 2008 results included a tax reduction of approximately $7.5 million associated with the settlement of historical corporate tax matters at Terasen. Excluding the tax reduction at Terasen, earnings for the third quarter of 2008 were $41.5 million or $0.26 per common share. Excluding the above one-time item, growth in earnings quarter over quarter was mainly due to higher earnings at Newfoundland Power associated with a shift in the quarterly distribution of annual purchased power expense, higher non-regulated hydroelectric production, increased earnings at FortisBC primarily due to lower energy supply costs and higher earnings at FortisAlberta mainly due to higher corporate tax recoveries. The increase was partially offset by lower earnings at Caribbean Regulated Utilities driven by a 3.25 per cent reduction in basic electricity rates at Caribbean Utilities, a lower allowed ROA at Belize Electricity and a loss of revenue at Fortis Turks and Caicos due to the impact of Hurricane Ike.

June 2008/June 2007 – Net earnings applicable to common shares were $29 million, or $0.19 per common share, for the second quarter of 2008 compared to earnings of $41 million, or $0.31 per common share, for the second quarter of 2007. Second quarter 2008 results included a $13 million, or $0.08 per common share, charge representing the Corporation's approximate 70 per cent share of disallowed previously incurred fuel and purchased power costs at Belize Electricity as well as a $2 million one-time charge at FortisOntario associated with repayment of interconnection-agreement related amounts received in the fourth quarter of 2007. Excluding the above one-time items, earnings for the second quarter of 2008 were $44 million compared to $41 million for the second quarter of 2007. Earnings were favourably impacted by a full quarter of earnings' contribution from the Terasen Gas companies, higher earnings at Newfoundland Power associated with a shift in the quarterly distribution of annual purchased power expense, increased non-regulated hydroelectric production and improved performance at Fortis Properties. Partially offsetting those items were lower earnings at FortisAlberta associated with higher corporate income taxes and higher corporate financing costs associated with the Terasen acquisition.

March 2008/March 2007 – Net earnings applicable to common shares were $91 million, or $0.58 per common share, for the first quarter of 2008, up $49 million from earnings of $42 million, or $0.38 per common share, for the first quarter of 2007. Growth in earnings was primarily attributable to the contribution from the Terasen Gas companies, acquired on May 17, 2007, and also reflected improved performance at Caribbean Utilities. The growth was partially offset by higher corporate financing costs associated with the Terasen acquisition and lower earnings at Newfoundland Power associated with a shift in the quarterly distribution of annual purchased power expense. Earnings' contribution from Caribbean Utilities during the first quarter of 2007 was reduced by $2 million associated with a one-time charge on the disposal of steam-turbine assets.

Management's Evaluation of Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure Controls and Procedures

The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintained disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2008 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting

The CEO and the CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2008 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance.

During the fourth quarter of 2008, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Subsequent Events

In February 2009, FortisAlberta issued $100 million of 30-year 7.06% unsecured debentures under the short-form base shelf prospectus that was filed in December 2008. The net proceeds were used to repay committed credit-facility borrowings incurred in support of the Company's capital expenditure program and for general corporate purposes.

In February 2009, TGI issued $100 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay $60 million of unsecured debentures that mature in June 2009.

Outlook

Gross consolidated capital expenditures are estimated to be approximately $1 billion in 2009 and approximately $4.5 billion over the next five years. The Corporation's capital program should drive growth in earnings and dividends.

With its substantial credit facilities and conservative capital structure, Fortis believes it has the financial flexibility to respond to the global economic downturn and volatility in the capital markets anticipated to continue in 2009. The Corporation and its utilities also expect to continue to have reasonable access to long-term capital in 2009.

The Corporation continues to pursue acquisitions for profitable growth, focusing on opportunities to acquire regulated natural gas and electric utilities in Canada, the United States and the Caribbean. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

Outstanding Share Data

As at March 10, 2009, the Corporation had issued and outstanding 169.8 million common shares; 5.0 million First Preference Shares, Series C; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; and 9.2 million First Preference Shares, Series G. Only the common shares of the Corporation have voting rights.

The number of common shares that would be issued upon conversion of share options, convertible debt and First Preference Shares, Series C and First Preference Shares, Series E as at March 10, 2009 is as follows:

Conversion of Securities into Common Shares

As at March 10, 2009 *(Unaudited)*

Security	Number of Common Shares *(millions)*
Stock Options	**4.1**
Convertible Debt	**1.8**
First Preference Shares, Series C	**6.0**
First Preference Shares, Series E	**9.7**
Total	**21.6**

Additional information, including the Fortis 2008 Annual Information Form, Management Information Circular and Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2008 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2008 Annual Report is consistent with that in the Annual Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for the training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review the shareholders' auditors' independence and auditors' fees. The 2008 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2008 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon the recommendation of the Audit Committee, have performed an audit of the 2008 Annual Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer

Barry V. Perry
Vice President, Finance and Chief Financial Officer

St. John's, Canada

Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the consolidated balance sheets of Fortis Inc. as at December 31, 2008 and 2007 and the consolidated statements of earnings, retained earnings, comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

St. John's, Canada,
January 30, 2009

Financials

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in millions of Canadian dollars)

ASSETS	2008	2007
Current assets		
Cash and cash equivalents	**$ 66**	$ 58
Accounts receivable	**681**	635
Prepaid expenses	**17**	19
Regulatory assets *(Note 4)*	**157**	119
Inventories *(Note 5)*	**229**	207
	1,150	1,038
Deferred charges and other assets *(Note 6)*	**279**	179
Regulatory assets *(Note 4)*	**203**	193
Future income taxes *(Note 19)*	**54**	37
Utility capital assets *(Note 7)*	**7,367**	6,748
Income producing properties *(Note 8)*	**541**	519
Intangibles, net of amortization *(Note 2)*	**9**	15
Goodwill *(Note 9)*	**1,575**	1,544
	$ 11,178	$ 10,273
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 26)*	**$ 410**	$ 475
Accounts payable and accrued charges	**874**	793
Dividends payable	**47**	43
Income taxes payable	**66**	30
Regulatory liabilities *(Note 4)*	**45**	20
Current installments of long-term debt and capital lease obligations *(Note 10)*	**240**	436
Future income taxes *(Note 19)*	**15**	7
	1,697	1,804
Deferred credits *(Note 11)*	**277**	261
Regulatory liabilities *(Note 4)*	**401**	372
Future income taxes *(Note 19)*	**61**	55
Long-term debt and capital lease obligations *(Note 10)*	**4,884**	4,623
Non-controlling interest *(Note 12)*	**145**	115
Preference shares *(Note 13)*	**320**	320
	7,785	7,550
Shareholders' equity		
Common shares *(Note 14)*	**2,449**	2,126
Preference shares *(Note 13)*	**347**	122
Contributed surplus	**9**	6
Equity portion of convertible debentures *(Note 10)*	**6**	6
Accumulated other comprehensive loss *(Note 16)*	**(52)**	(88)
Retained earnings	**634**	551
	3,393	2,723
	$ 11,178	$ 10,273

Commitments *(Note 27)*

Contingent Liabilities *(Note 28)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

Geoffrey Hyland

Geoffrey F. Hyland,
Director

David G. Norris,
Director

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2008**	2007
Revenue	**$ 3,903**	$ 2,718
Expenses		
Energy supply costs	**2,112**	1,287
Operating	**743**	617
Amortization	**348**	273
	3,203	2,177
Operating Income	**700**	541
Finance charges *(Note 17)*	**363**	299
Gain on sale of property *(Note 18)*	**–**	(8)
	363	291
Earnings Before Corporate Taxes and Non-Controlling Interest	**337**	250
Corporate taxes *(Note 19)*	**65**	36
Net Earnings Before Non-Controlling Interest	**272**	214
Non-controlling interest	**13**	15
Net Earnings	**259**	199
Preference share dividends	**14**	6
Net Earnings Applicable to Common Shares	**$ 245**	$ 193
Earnings Per Common Share *(Note 14)*		
Basic	**$ 1.56**	$ 1.40
Diluted	**$ 1.52**	$ 1.32

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Retained Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2008**	2007
Balance at Beginning of Year	**$ 551**	$ 486
Net Earnings Applicable to Common Shares	**245**	193
	796	679
Dividends on Common Shares	**(162)**	(128)
Balance at End of Year	**$ 634**	$ 551

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2008**	2007
Net Earnings	**$ 259**	$ 199
Unrealized foreign currency translation gains (losses) on net investments in self-sustaining foreign operations	**115**	(70)
(Losses) gains on hedges of net investments in self-sustaining foreign operations	**(92)**	48
Corporate tax recovery (expense)	**13**	(9)
Change in Unrealized Foreign Currency Translation Gains (Losses), Net of Hedging Activities and Tax *(Note 16)*	**36**	(31)
Comprehensive Income	**$ 295**	$ 168

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2008**	2007
Operating Activities		
Net earnings	**$ 259**	$ 199
Items not Affecting Cash		
Amortization – utility capital assets and income producing properties	**339**	261
Amortization – intangibles and other	**9**	12
Future income taxes *(Note 19)*	**14**	–
Non-controlling interest	**13**	15
Write-down of deferred power costs – Belize Electricity *(Note 4)*	**18**	–
Gain on sale of property *(Note 18)*	**–**	(8)
Other	**(7)**	–
Change in long-term regulatory assets and liabilities	**(23)**	11
	622	490
Change in non-cash operating working capital	**41**	(117)
	663	373
Investing Activities		
Change in deferred charges, other assets and deferred credits	**(31)**	(4)
Utility capital expenditures	**(890)**	(790)
Contributions in aid of construction	**85**	73
Income producing property capital expenditures	**(14)**	(13)
Proceeds on sale of capital assets	**18**	4
Business acquisitions, net of cash acquired *(Note 21)*	**(22)**	(1,303)
	(854)	(2,033)
Financing Activities		
Change in short-term borrowings	**(69)**	103
Proceeds from long-term debt, net of issue costs	**662**	797
Repayments of long-term debt and capital lease obligations	**(431)**	(363)
Net (repayments) borrowings under committed credit facilities	**(309)**	25
Advances from (to) non-controlling interest	**3**	(3)
Issue of common shares, net of costs	**308**	1,267
Issue of preference shares, net of costs	**223**	–
Dividends		
Common shares	**(162)**	(128)
Preference shares	**(14)**	(6)
Subsidiary dividends paid to non-controlling interest	**(15)**	(12)
	196	1,680
Effect of exchange rate changes on cash and cash equivalents	**3**	(3)
Change in Cash and Cash Equivalents	**8**	17
Cash and Cash Equivalents, Beginning of Year	**58**	41
Cash and Cash Equivalents, End of Year	**$ 66**	$ 58

Supplementary Information to Consolidated Statements of Cash Flows *(Note 23)*

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

1. Description of the Business

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving primarily residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving primarily residential, commercial and industrial customers.

In addition to providing transmission and distribution services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the propane distribution system in Whistler, British Columbia, providing service to mainly residential and commercial customers.

Regulated Electric Utilities – Canadian

a. *FortisAlberta*: FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta.

b. *FortisBC*: Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 megawatts ("MW"). Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 269-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power*: Newfoundland Power is the principal distributor of electricity in Newfoundland. Newfoundland Power has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian*: Includes Maritime Electric and FortisOntario. Maritime Electric is the principal distributor of electricity on Prince Edward Island. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario's operations primarily include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a ten-year lease agreement that expires in April 2012.

Regulated Electric Utilities – Caribbean

a. *Belize Electricity*: Belize Electricity is the principal distributor of electricity in Belize, Central America. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

b. *Caribbean Utilities*: Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed generating capacity of 137 MW. Fortis has an approximate 57 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. The impact on 2008 earnings was not material. Going forward, this change in the Company's fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' financial results.

c. *Fortis Turks and Caicos*: Includes P.P.C. Limited ("PPC") and Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic"). Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands. The Company has a combined diesel-fired generating capacity of 48 MW.

Non-Regulated – Fortis Generation

a. *Belize*: Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. The hydroelectric generation operations in Belize are conducted through the Corporation's indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.

b. *Ontario*: Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires April 30, 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

c. *Central Newfoundland*: Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Fortis Properties holds directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation under a 30-year power purchase agreement expiring in 2033 (Note 28).

d. *British Columbia*: Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013.

e. *Upper New York State*: Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, operating under licences from the US Federal Energy Regulatory Commission. Hydroelectric generation operations in Upper New York State are conducted through the Corporation's indirect wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 20 hotels comprised of more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment. This segment includes finance charges, including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen Inc. corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. While currently not significant, financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

2. Summary of Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), including selected accounting treatments that differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP by entities not subject to rate regulation. The differences are described in Note 2 under the headings "Regulation", "Utility Capital Assets", "Employee Future Benefits", "Income Taxes" and "Revenue Recognition", and in Note 4.

All amounts presented are in Canadian dollars unless otherwise stated.

Regulation

Terasen Gas Companies and FortisBC

The Terasen Gas companies and FortisBC are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. TGI, TGVI and FortisBC operate under both cost-of-service regulation and performance-based rate-setting ("PBR") methodologies as administered by the BCUC. The BCUC provides for the use of a future test year in the establishment of rates and, pursuant to this method, provides for the forecasting of energy to be sold, together with all the costs of the utilities, and provides a rate of return on a deemed capital structure applied to approved rate base assets. Rates are fixed to permit the utilities to collect all of their costs, including the allowed rate of return on common shareholders' equity ("ROE").

Under the PBR mechanism, TGI and customers equally share in achieved earnings above or below the allowed ROE. When TGI's earned ROE is greater than 200 basis points above the allowed ROE for two consecutive years, the PBR mechanism may be reviewed. Under the PBR mechanism, TGVI is permitted to retain 100 per cent of earnings derived from lower-than-forecasted controllable operating and maintenance expenses; however, TGVI is not provided any relief from increased controllable operating and maintenance expenses. The PBR agreements at TGI and TGVI have been extended until 2009. During 2008, the BCUC extended the PBR agreement for FortisBC for the years 2009 through 2011. Under the PBR agreement, FortisBC and customers equally share achieved earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE. Any excess is subject to deferral treatment. FortisBC's portion of the PBR incentive is subject to the Company meeting certain performance standards and BCUC approval.

TGI's allowed ROE was 8.62 per cent for 2008 (2007 – 8.37 per cent) on a deemed capital structure of 35 per cent common equity. TGVI's allowed ROE was 9.32 per cent for 2008 (2007 – 9.07 per cent) on a deemed capital structure of 40 per cent common equity. FortisBC's allowed ROE was 9.02 per cent for 2008 (2007 – 8.77 per cent) on a deemed capital structure of 40 per cent common equity. The allowed ROE at each of TGI, TGVI and FortisBC is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. TGI, TGVI and FortisBC apply for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment and/or through the operation of the PBR mechanisms.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC"), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *AUC Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing.

FortisAlberta operates under cost-of-service regulation as prescribed by the AUC. The AUC provides for the use of a future test year in the establishment of rates associated with the distribution business and, pursuant to this method, rate orders issued by the AUC establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed ROE was 8.75 per cent for 2008 (2007 – 8.51 per cent) on a deemed capital structure of 37 per cent common equity. FortisAlberta's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Newfoundland Power

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operation and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power. Newfoundland Power operates under cost-of-service regulation as administered by the PUB. The PUB provides for the use of a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the forecast rate of return on approved rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establish the revenue requirement upon which Newfoundland Power's customer rates are determined. Between test years, Newfoundland Power's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. Newfoundland Power's allowed ROE for 2008 was 8.95 per cent (2007 – 8.60 per cent) on a deemed capital structure of 45 per cent common equity. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Maritime Electric

Maritime Electric operates under a traditional cost-of-service regulatory model as prescribed by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (Prince Edward Island). IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a deemed capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 10.00 per cent for 2008 (2007 – 10.25 per cent) on a deemed capital structure of 40 per cent common equity. Maritime Electric applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario

Canadian Niagara Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario) as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power operates under cost-of-service regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In 2008, the utility's electricity distribution rates were based upon costs derived from a 2004 test year using a deemed capital structure of 46.7 per cent common equity. In accordance with the OEB's plan, the utility will move to a 40 per cent common equity capital structure over a three-year period. FortisOntario's allowed ROE was 9 per cent for 2008 (2007 – 9 per cent).

Cornwall Electric is exempt from many aspects of the above Acts and is also subject to a 35-year Franchise Agreement with the City of Cornwall, expiring in 2033. The rate-setting mechanism is subject to a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Belize Electricity

Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). The PUC oversees the rates that may be charged in respect of utility services and the standards that must be maintained in relation to such services and uses a future test year to set rates. In addition, the PUC is responsible for the award of licences and for monitoring and enforcing compliance with licences' conditions. The basic electricity rate at Belize Electricity is comprised of two components. The first component is value-added delivery ("VAD") and the second is the cost of fuel and purchased power ("COP"), including the variable cost of generation, which is a flow through in customer rates. The VAD component of the tariff allows the Company to recover its operating expenses, transmission and distribution expenses, taxes and amortization, and an allowed rate of return on rate base assets ("ROA"). Belize Electricity's allowed ROA was set at 10.00 per cent effective July 1, 2008 (2007 – 10.00 to 15.00 per cent).

Caribbean Utilities

Caribbean Utilities has been generating and distributing electricity in its franchise area of Grand Cayman, Cayman Islands, under a licence from the Government of the Cayman Islands (the "Government") since May 10, 1966. Effective January 1, 2008, new licences were granted to Caribbean Utilities. The new exclusive transmission and distribution ("T&D") licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The new generation licence is for a period of 21.5 years, expiring September 2029. The new licences establish a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer rates are set using an initial targeted allowed ROA of 10 per cent, down from an allowed ROA of 15 per cent that was permitted under the previous licence. The new licences detail the role of the Electric Regulatory Authority, which will oversee all licences, establish and enforce licence standards, review the RCAM and annually approve capital expenditures.

Fortis Turks and Caicos

Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through PPC and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated October 1987 and November 1986 (collectively, the "Agreements"), respectively. Among other matters, these Agreements describe how electricity rates are to be set by the Government of the Turks and Caicos Islands, using a future test year, in order to provide Fortis Turks and Caicos with an allowed ROA of 17.5 per cent (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of Allowable Operating Profits on a cumulative basis (the "cumulative shortfall").

2. *Summary of Significant Accounting Policies (cont'd)*

Regulation (cont'd)

Fortis Turks and Caicos makes annual submissions to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the cumulative shortfalls. The submissions for 2008 calculated the Allowable Operating Profit for 2008 to be $22 million (US$18 million) and the cumulative shortfall at December 31, 2008 to be $22 million (US$18 million). Fortis Turks and Caicos has a legal right under the Agreements to request an increase in electricity rates to begin to recover the cumulative shortfalls. The recovery would, however, be dependent on future sales volumes and expenses.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with maturities of three months or less from the date of acquisition.

Inventories

Inventories are valued at the lower of weighted-average cost and net realizable value.

Utility Capital Assets

Utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966 with subsequent additions at cost. Utility capital assets of Caribbean Utilities are stated on the basis of appraised values as at November 30, 1984 with subsequent additions at cost. Utility capital assets of Fortis Turks and Caicos are stated at appraised values as at September 18, 1986. Subsequent additions are at cost except for the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by agreements dated November 29, 1986 and October 8, 1987 for US$2.00, in aggregate, as valued in the books of the companies. Utility capital assets of all other utility operations are stated at cost.

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being reduced annually by an amount equal to the charge for amortization provided on the related assets.

As required by their respective regulators, amortization expense at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for future asset removal and site restoration costs, net of salvage proceeds. The amount provided for in amortization expense is recorded as a long-term regulatory liability. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. At December 31, 2008, the long-term regulatory liability for future asset removal and site restoration costs was $337 million (December 31, 2007 – $319 million) (Note 4 *(xii)*). The Terasen Gas companies record actual asset removal and site restoration costs, net of salvage proceeds, against accumulated amortization. In the absence of a current depreciation study approved by its regulator, a reasonable estimate of any regulatory asset or liability associated with future asset removal and site restoration costs for the Terasen Gas companies cannot be made as at December 31, 2008. FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record asset removal and site restoration costs in earnings when incurred, and these costs did not have a material impact on the Corporation's 2008 and 2007 earnings.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities, as required by their respective regulators, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization expense when it is collected in customer gas and electricity rates. At FortisOntario and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of utility capital assets is recorded immediately in earnings. In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity would be recognized in the current period. The loss charged to accumulated amortization in 2008 was approximately $31 million (2007 – $26 million).

Utility capital assets include inventories held for the development, construction and maintenance of other utility capital assets. When put into service, the inventories are amortized using the straight-line method based on estimated service lives of the capital assets to which they are added.

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred while replacements and betterments are capitalized.

As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity and, commencing May 2008, Caribbean Utilities capitalize overhead costs that are not directly attributable to specific utility capital assets but which relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulators. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. The general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. In 2008, GEC totalled $57 million (2007 – $42 million).

As required by their respective regulators, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities include an equity component in the allowance for funds used during construction ("AFUDC") that is included in the cost of utility capital assets. Since AFUDC includes both an interest component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. AFUDC is deducted from finance charges and AFUDC capitalized during 2008 was $13 million (2007 – $8 million) (Note 17), including an equity component of $6 million (2007 – $3 million). AFUDC is charged to operations through amortization expense over the estimated service lives of the applicable utility capital assets.

FortisAlberta maintains a regulatory tax basis adjustment account, which represents the excess of the deemed tax basis of the Company's utility capital assets for regulatory rate-making purposes as compared to the Company's tax basis for income tax purposes. The regulatory tax basis adjustment is being amortized over the estimated service lives of the Company's utility capital assets by an offset against the provision for amortization. The regulatory tax basis adjustment is recorded as a reduction in utility capital assets. During 2008, amortization expense was reduced by $4 million (2007 – $5 million) for the amortization of the regulatory tax basis adjustment.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates range from 0.4 per cent to 39.0 per cent. The composite rate of amortization before reduction for amortization of contributions in aid of construction for 2008 was 3.5 per cent (2007 – 3.6 per cent).

The service life ranges and average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows.

	2008		2007	
	Service Life Ranges (Years)	**Average Remaining Service Life (Years)**	Service Life Ranges (Years)	Average Remaining Service Life (Years)
Distribution				
Gas	**10–100**	**35**	10–100	33
Electricity	**5–75**	**28**	10–75	28
Transmission				
Gas	**10–50**	**37**	10–50	38
Electricity	**10–75**	**35**	10–75	34
Generation	**5–75**	**29**	5–75	32
Other	**5–67**	**14**	5–67	14

Income Producing Properties

Income producing properties of Fortis Properties, which include office buildings, shopping malls, hotels, land and related equipment and tenant inducements, are recorded at cost. Buildings are being amortized using the straight-line method over an estimated useful life of 60 years. Fortis Properties amortizes tenant inducements over the initial terms of the leases to which they relate. The lease terms vary to a maximum of 20 years. Equipment is recorded at cost and is amortized on a straight-line basis over a range of 2 years to 25 years.

Maintenance and repairs of income producing properties are charged to earnings in the period incurred while replacements and betterments are capitalized.

Leases

Leases which transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Capital leases are depreciated over the lease term. Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

2. Summary of Significant Accounting Policies (cont'd)

Intangibles

Intangibles include the estimated fair value of water rights associated with the Rankine hydroelectric generating station in Ontario and intangibles associated with the acquisition of Terasen. The Rankine water rights are being amortized using the straight-line method over the estimated life of the asset to April 30, 2009. As at April 30, 2009, in accordance with the Niagara Exchange Agreement, the Corporation's water entitlement on the Niagara River associated with the Rankine hydroelectric generating station will expire and associated earnings' contribution will cease.

Upon the acquisition of Terasen, $10 million was assigned as the value associated with customer contracts at CWLP. The intangible is being amortized using the straight-line method over the remaining term of the contracts to December 31, 2011. Approximately $1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization.

As at December 31, 2008, the net book value of intangibles was $9 million (net of accumulated amortization of $28 million) (December 31, 2007 – $15 million (net of accumulated amortization of $21 million)).

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives and deferred charges and other assets when events or changes in circumstances may indicate that the asset's carrying value exceeds the total undiscounted cash flows expected from its use and eventual disposition. An impairment loss, calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the consolidated financial statements as a result of asset impairments for the years ended December 31, 2008 and 2007.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash inflow stream, such an asset is tested individually and an impairment is recorded if the future cash inflows are no longer sufficient to recover the carrying value of the generating facility. Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of a regulated asset's carrying value, including a fair return on capital or assets, is provided through customer gas and electricity rates approved by the respective regulatory authorities. The cash inflows for regulated enterprises are not asset-specific but are pooled for the entire regulated enterprise.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings. To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit, to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No goodwill impairment provision has been determined for the years ended December 31, 2008 and 2007.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group Registered Retirement Savings Plans ("RRSPs") for its employees. The costs of the defined contribution pension plans and RRSPs are expensed as incurred. The accrued pension benefit obligation and the value of pension costs of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of the discount rate, expected plan investment performance, salary escalation and retirement ages of employees.

With the exception of the Terasen Gas companies and Newfoundland Power, pension plan assets are valued at fair value. At the Terasen Gas companies and Newfoundland Power, plan assets are valued using the market-related value, where investment returns in excess of or below expected returns are recognized in the asset value over a period of three years. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the greater of the benefit obligation and the fair value of plan assets (the market-related value of plan assets at the Terasen Gas companies and Newfoundland Power), at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

On January 1, 2000, Newfoundland Power prospectively applied Section 3461 of the Canadian Institute of Chartered Accountants' ("CICA") Handbook. The Company is amortizing the resulting transitional obligation on a straight-line basis over 18 years, the expected average remaining service period of the plan members at that time.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is being recovered in customer rates based on the cash payments made.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for defined benefit and defined contribution pension plans, which is expected to be recovered, or refunded, in future customer rates, is subject to deferral treatment (Note 4 *(viii)* and *(xvii)*).

Supplementary and Other Post-Employment Benefit ("OPEB") Plans
The Corporation, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits through defined benefit plans, including certain health and dental coverage, for qualifying members.

Additionally, the Corporation, Terasen Gas companies, FortisAlberta, Newfoundland Power and Maritime Electric provide retirement allowances and supplemental retirement plans for certain of its executive employees. The accrued benefit obligation and the value of the costs associated with the supplementary and OPEB plans are actuarially determined using the projected benefits method prorated on service and best-estimate assumptions. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the benefit obligation, at the beginning of the fiscal year, and any unamortized past service costs are deferred and amortized over the average remaining service period of active employees.

As approved by the respective regulators, the costs of OPEB plans at FortisAlberta and Newfoundland Power are recovered in customer rates based on the cash payments made, with the exception of retirement allowances arising from Newfoundland Power's 2005 Early Retirement Program. The cost of supplemental pension plans at FortisAlberta is also recovered in customer rates based on the cash payments made.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for OPEB and supplemental pension plans, which is expected to be recovered, or refunded, in future customer rates, is subject to deferral treatment (Note 4 *(iv)*).

Stock-Based Compensation

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 Stock Option Plan ("2002 Plan") and 2006 Stock Option Plan ("2006 Plan") (Note 15). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and is amortized over the four-year vesting period of the options granted. The offsetting entry is an increase to contributed surplus for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise, the proceeds of the options are credited to capital stock at the option prices, and the fair value of the options, as previously recorded, is reclassified from contributed surplus to capital stock. An exercise of options below the current market price has a dilutive effect on capital stock and shareholders' equity.

The Corporation also records compensation expense associated with its Directors' Deferred Share Unit ("DSU") and Performance Share Unit ("PSU") Plans using the fair value method, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU and PSU liabilities is based on the Corporation's common share closing price at the end of each reporting period.

2. Summary of Significant Accounting Policies (cont'd)

Foreign Currency Translation

The assets and liabilities of foreign operations, all of which are self-sustaining and denominated in US dollars or in a currency pegged to the US dollar, are translated at the exchange rate in effect at the balance sheet dates. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00 = US$1.00. The exchange rate in effect at December 31, 2008 was US$1.00 = CDN$1.22 (December 31, 2007 – US$1.00 = CDN$0.99). The resulting unrealized translation gains and losses are accumulated as a separate component of shareholders' equity within accumulated other comprehensive loss and the current period change is recorded in other comprehensive income. Revenue and expense items are translated at the average exchange rate in effect during the period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are recorded separately in other comprehensive income.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing on the balance sheet date. Revenue and expense items denominated in foreign currencies are translated at the exchange rate prevailing on the transaction date. Gains and losses on translation are included in earnings.

Financial Instruments

The Corporation designates its financial instruments into one of the following five categories: (i) held for trading, (ii) available for sale, (iii) held to maturity, (iv) loans and receivables, or (v) other financial liabilities. All financial instruments are initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value with any change in fair value recorded in earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

Derivative financial instruments, including derivative features embedded in financial instruments or other contracts that are not considered closely related to the host financial instrument or contract, are generally classified as held for trading and, therefore, must be measured at fair value with changes in fair value recorded in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates (Note 4 *(xvi)*). Currently, the Corporation limits the use of derivative financial instruments to those that qualify as hedges, as discussed under "Hedging Relationships".

The Corporation has selected January 1, 2003 as the transition date for recognizing embedded derivatives and, therefore, recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired or substantially modified on or after January 1, 2003. While some of the Corporation's long-term debt contracts have prepayment options that qualify as embedded derivatives to be separately recorded, none have been recorded as they are immaterial to the Corporation's results of operations and financial position.

The Corporation's policy is to recognize transaction costs associated with financial assets and liabilities, that are classified as other than held for trading, as an adjustment to the cost of those financial assets and liabilities recorded on the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument.

Effective January 1, 2008, the Corporation has adopted CICA Handbook Section 3862, *Financial Instruments – Disclosures* and Section 3863, *Financial Instruments – Presentation*, which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed. The new disclosures are provided in Notes 25 and 26.

Hedging Relationships

At December 31, 2008, the Corporation's hedging relationships consisted of interest rate swap contracts, a foreign exchange forward contract, natural gas derivatives and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

Fortis Properties has designated its interest rate swap contracts as hedges of the cash flow risk related to floating-rate long-term debt. The interest rate swap contracts are valued at the present value of future cash flows based on published forward future interest rate curves. The fair value and subsequent changes in fair value of interest rate swap contracts that are in effective hedging relationships are recorded in other comprehensive income.

The foreign exchange forward contract is held by TGVI and is designated as a hedge of the cash flow risk related to approximately US$55 million required to be paid under a contract for the construction of a liquefied natural gas ("LNG") storage facility. The foreign exchange forward contract is valued at the present value of future cash flows based on published forward future foreign exchange market rate curves. Any change in the fair value of the foreign exchange forward contract is deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the Terasen Gas companies have floating, rather than fixed, prices. The fair values of the natural gas derivatives reflect the estimated amounts, based on published forward curves, that the Corporation would have to receive or pay if forced to settle all outstanding contracts at the balance sheet date. As at December 31, 2008, none of the natural gas derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The Corporation's earnings from and net investments in self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The Corporation has designated its corporately held US dollar long-term debt as a hedge of the foreign exchange risk related to its net investments in self-sustaining foreign subsidiaries. The unrealized foreign exchange gains and losses on the US dollar-denominated long-term debt and the partially offsetting unrealized foreign exchange losses and gains on the foreign net investments are recognized in other comprehensive income.

Income Taxes

Except as described below for the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power, the Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted or substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense (recovery) is recognized for the estimated income taxes payable (receivable) in the current year.

The Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power follow the cash taxes payable method of accounting for income taxes, as prescribed by their respective regulators. Under this methodology, except for certain deferred accounts specifically prescribed by the respective regulators, current customer rates do not include the recovery of future income taxes related to certain temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable.

Entities not subject to rate regulation generally recognize future income tax assets and liabilities for temporary differences between the tax and accounting basis of all assets and liabilities. In the absence of rate regulation, future income tax assets and liabilities would have been recorded and the Corporation's future income tax liabilities and future income tax assets would have increased by approximately $364 million and $18 million, respectively, as at December 31, 2008 (December 31, 2007 – $344 million and $29 million, respectively).

Belize Electricity is subject to corporate tax; however, it is capped at 1.75 per cent of gross revenues. Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize for the term of the 50-year power purchase agreement.

The Corporation does not provide for income taxes on undistributed earnings of foreign subsidiaries that are not expected to be repatriated in the foreseeable future.

2. Summary of Significant Accounting Policies (cont'd)

Revenue Recognition

Revenue at the Corporation's regulated utilities is recognized in a manner approved by each utility's regulatory authority. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authorities and is generally bundled to include service associated with generation, transmission and distribution, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

As required by the respective regulatory authorities, revenue from the sale of gas by the Terasen Gas companies and electricity by FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on the accrual basis. Gas and electricity are metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity consumed but not yet billed to customers are estimated and accrued as revenue at each period end.

As required by the PUC, revenue from the sale of electricity by Belize Electricity is recognized as monthly billings are rendered to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. The difference between recognizing revenue on a billed versus an accrual basis is recorded on the balance sheet as a regulatory liability (Note 4 *(xiii)*).

FortisAlberta reports revenue and expenses related to transmission services on a net basis in revenue. At the Corporation's other regulated utilities, transmission revenue and expenses are recorded on a gross basis. As stipulated by the AUC, FortisAlberta is required to arrange and pay for transmission service with Alberta Electric System Operator ("AESO") and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its AUC-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. The rates collected are based on forecasted transmission expenses and, for certain elements of the transmission costs, FortisAlberta is subject to the risk of actual expenses being different from the forecast revenue relating to transmission services. All other differences are subject to deferral treatment and are either collected, or refunded, in future customer rates (Note 4 *(iii)*).

FortisOntario's regulated operations are primarily comprised of the operations of Cornwall Electric and Canadian Niagara Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power are not bundled. At Canadian Niagara Power, the cost of power and transmission are a flow through to customers and these costs and revenue associated with the recovery of these costs are tracked and recorded separately. This treatment is consistent with other regulated utilities in Ontario as required under OEB regulation. The amount of transmission revenue tracked separately at Canadian Niagara Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements. Generally, production from the Corporation's generation stations is metered at or near month end and production data is used to record revenue earned.

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements. The leases are primarily of a net nature, with tenants paying basic rental plus a pro rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenant's sales. Expenses recovered from tenants are recorded as revenue. The escalation of lease rates included in long-term leases is recorded in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations ("AROs")

AROs, including conditional AROs, are recorded as a liability at fair value, with a corresponding increase to utility capital assets or income producing properties. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of a fair value can be determined.

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time.

No significant environmental issues have been identified with respect to the Corporation's hydroelectric generation and transmission and distribution assets. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights of way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

Capital Disclosures

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 1535, *Capital Disclosures*, which requires the Corporation to disclose additional information about its capital and the manner in which it is managed. The additional disclosure includes quantitative and qualitative information regarding the Corporation's objectives, policies and processes for managing capital. The new disclosures are provided in Note 24.

Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

3. Future Accounting Changes

International Financial Reporting Standards ("IFRS")

In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010 and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section – *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to this Exposure Draft. Fortis is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Fortis does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required, as well as system changes that may be necessary to gather and process the information.

3. Future Accounting Changes (cont'd)

Rate-Regulated Operations

Effective January 1, 2009, the AcSB amended: (i) CICA Handbook Section 1100, *Generally Accepted Accounting Principles* removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; and (ii) Section 3465, *Income Taxes* to require the recognition of future income tax liabilities and assets as well as offsetting regulatory assets and liabilities by entities subject to rate regulation.

Effective January 1, 2009, the impact on Fortis of the amendment to Section 3465, *Income Taxes* will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the cash taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes* as at December 31, 2008, would have been an increase in future income tax assets and future income tax liabilities of $24 million and $497 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of $24 million and $497 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates and the separate disclosure of future income tax assets and liabilities that are currently not recognized.

Effective January 1, 2009, with the removal of the temporary exemption from Section 1100, the Corporation must now apply Section 1100 for the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. All assets and liabilities arising from rate regulation described in Note 4 do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Corporation to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. The Corporation's regulatory assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Corporation's consolidated financial statements if it had adopted the removal of the temporary exemption from Section 1100 for the year ended December 31, 2008. Fortis is continuing to assess any additional implications on its financial reporting related to accounting for rate-regulated operations.

Goodwill and Intangible Assets

Effective January 1, 2009, the Corporation will adopt the new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. This Section, which replaces Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The currently estimated effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3064 as at December 31, 2008, would have been an increase in intangible assets of $234 million, a reduction in utility capital assets of $232 million and a reduction in deferred charges and other assets of $2 million for the reclassification of the net book value of land and transmission rights, computer software costs and franchise costs. The Corporation is continuing to assess and quantify any additional financial reporting impacts from adopting this standard.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, the Corporation will adopt the new Emerging Issues Committee ("EIC")-173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*, which was issued on January 20, 2009. EIC-173 requires that the Corporation's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. As at December 31, 2008, only the Corporation's derivative financial instruments were recorded at fair value (Note 25), the majority of which were out-of-the-money and recorded as a liability. The Corporation is continuing to assess any additional financial reporting impacts of adopting this EIC.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues associated with certain costs incurred that will be or are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be or are expected to be refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Based on previous, existing or expected future regulatory orders or decisions, the Corporation's regulated utilities have recorded the following amounts expected to be recovered from, or refunded to, customers in future periods.

Regulatory Assets

(in millions)	**2008**	2007	**Remaining recovery period (Years)**
Rate stabilization accounts – Terasen Gas companies *(i)*	**$ 76**	$ 99	1–3
Rate stabilization accounts – electric utilities *(ii)*	**78**	66	Various
AESO charges deferral *(iii)*	**64**	8	2
Regulatory OPEB plan asset *(iv)*	**51**	44	Indeterminable
Income taxes recoverable on OPEB plans *(v)*	**18**	16	Indeterminable
Deferred capital asset amortization *(vi)*	**8**	12	1–2
Residential unbundling *(vii)*	**7**	9	1–3
Deferred pension costs *(viii)*	**7**	8	7
Southern Crossing Pipeline tax reassessment *(ix)*	**7**	7	Indeterminable
Energy management costs *(x)*	**7**	6	1–8
Other regulatory assets *(xi)*	**37**	37	Indeterminable
Total regulatory assets	**360**	312	
Less: current portion	**(157)**	(119)	1
Long-term regulatory assets	**$ 203**	$ 193	

Regulatory Liabilities

(in millions)	**2008**	2007	**Remaining settlement period (Years)**
Future asset removal and site restoration provision *(xii)*	**$ 337**	$ 319	Indeterminable
Rate stabilization accounts – Terasen Gas companies *(i)*	**32**	–	1–3
Rate stabilization accounts – electric utilities *(ii)*	**9**	–	1
Unbilled revenue liability *(xiii)*	**15**	22	Indeterminable
PBR incentive liabilities *(xiv)*	**13**	14	1
Southern Crossing Pipeline deferral *(xv)*	**9**	5	1–5
Fair value of the foreign exchange forward contract *(xvi)*	**7**	–	Indeterminable
Pension deferral *(xvii)*	**4**	6	1–5
Other regulatory liabilities *(xviii)*	**20**	26	Indeterminable
Total regulatory liabilities	**446**	392	
Less: current portion	**(45)**	(20)	1
Long-term regulatory liabilities	**$ 401**	$ 372	

Description of the Nature of Regulatory Assets and Liabilities

(i) *Rate Stabilization Accounts – Terasen Gas Companies*

The rate stabilization accounts at the Terasen Gas companies are amortized and recovered through customer rates as approved by the BCUC. The rate stabilization accounts mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility.

4. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

At TGI, a Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual-versus-forecast gas volumes consumed by residential and commercial customers. Additionally, a Commodity Cost Reconciliation Account ("CCRA") and a Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The CCRA also accumulates the changes in fair value of TGI's natural gas commodity swaps.

At TGVI, a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on TGVI's earnings of natural gas cost volatility. The GCVA also accumulates the changes in the fair value of TGVI's natural gas commodity swaps. TGVI also maintains a Revenue Deficiency Deferral Account ("RDDA") to accumulate unrecovered costs of providing service to customers or to draw down such costs where earnings exceed the allowed ROE as set by the BCUC. During 2008 and 2007, the RDDA has decreased as achieved earnings have exceeded the allowed ROE.

The RSAM is anticipated to be refunded through rates over a three-year period, with a total balance outstanding as at December 31, 2008 of $8 million. The MCRA, CCRA and GCVA accounts are anticipated to be fully recovered, or refunded, within the next fiscal year. In the absence of rate regulation, the amounts in the rate stabilization accounts would not be deferred but would be recorded in earnings as incurred. The recovery or refund of amounts in the rate stabilization accounts is dependent on actual natural gas consumption volumes and on annually approved customer rates.

As at December 31, 2008, the balances in the RSAM and MCRA were in a payable position, as compared to a receivable position as at December 31, 2007.

(ii) Rate Stabilization Accounts – Electric Utilities

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos) are recovered, or refunded, through customer rates as approved by the respective regulatory authorities. The rate stabilization accounts primarily mitigate the effect on earnings of the variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level. Additionally, at Newfoundland Power the PUB has ordered the provision of a weather normalization account to adjust for the effect of variations in weather conditions when compared to long-term averages. This reduces Newfoundland Power's year-to-year earnings volatility that would otherwise result from such fluctuations in revenue and purchased power. The recovery period of the rate stabilization accounts, with the exception of Newfoundland Power's weather normalization account, whose recovery period is not determinable, ranges from one year to five years and is subject to periodic review by the respective regulators.

As at December 31, 2008, the balance in Belize Electricity's rate stabilization account was in a payable position, as compared to a receivable position as at December 31, 2007. During the second quarter of 2008, a downward $18 million adjustment was made to Belize Electricity's cost of power rate stabilization account reflecting, in substance, the disallowance of previously incurred fuel and purchased power costs as a result of the Final Decision by the PUC on Belize Electricity's 2008/2009 rate application.

The balance in Newfoundland Power's weather normalization account should approach zero over time because it is based on long-term averages for weather conditions. As ordered by the PUB, approximately $7 million of the weather normalization account is to be amortized equally over 2008 through 2012. In the absence of rate regulation, the fluctuations in revenue and purchased power would be recorded in earnings in the period in which they occurred. The recovery period of the remaining balance of the weather normalization account is not determinable as it depends on weather conditions in the future.

As at December 31, 2008, $12 million in pre-2004 costs deferred in the Energy Cost Adjustment Mechanism ("ECAM") account at Maritime Electric remained to be amortized. As approved by IRAC, the remaining amount is to be amortized and collected from customers at a rate of $2 million per year over a recovery period of six years. Annual deferral of energy costs to the ECAM account is recovered from, or refunded to, customers, as approved by IRAC, over a rolling eight-month period.

In the absence of rate regulation, the cost of fuel and/or purchased power would be expensed as incurred.

(iii) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenues collected for various items, such as transmission costs incurred and billed through to customers, that are subject to deferral to be collected in future customer rates. As at December 31, 2008, the balance of the AESO charges deferral account, comprised of the 2008 AESO charges deferral balance of $57 million and the unsold portion of the 2007 AESO charges deferral balance, is expected to be collected in customer rates in 2010 and 2009, respectively. In the absence of rate regulation, the costs would be expensed as incurred and no deferral treatment would be permitted.

During 2007, FortisAlberta sold approximately $28 million and $38 million of the 2006 and 2007 AESO charges deferral accounts, respectively, to a Canadian chartered bank for proceeds of approximately $28 million and $38 million, respectively. Proceeds included cash consideration of $64 million and receivables of approximately $2 million due in February 2009 and 2010.

(iv) *Regulatory OPEB Plan Asset*
At FortisAlberta and Newfoundland Power, and prior to 2005 at FortisBC, the cash cost of providing OPEB plans is being collected in customer rates as permitted by the respective regulators. Effective 2005, as permitted by the BCUC, the recovery from customers of the cost of OPEB plans at FortisBC is based on cash costs plus a partial recovery of the full accrual cost of OPEB plans. The regulatory OPEB asset represents the deferred portion of the benefit expense at FortisAlberta, FortisBC and Newfoundland Power that is expected to be recovered from customers in future rates. In the absence of rate regulation, the benefit expense would be recognized on an accrual basis as actuarially determined with no deferral of costs recorded on the balance sheet. FortisAlberta's and FortisBC's regulatory OPEB assets are not subject to a regulatory return.

(v) *Income Taxes Recoverable on OPEB Plans*
At TGI, the regulator allows OPEB plan costs to be collected in customer gas rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. Since TGI accounts for income taxes using the cash taxes payable method, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer gas rates. In the absence of rate regulation, the income tax would not be deferred.

(vi) *Deferred Capital Asset Amortization*
Newfoundland Power deferred the recovery of a $6 million increase in capital asset amortization in each of 2006 and 2007, in accordance with a PUB order. The approximate $12 million balance at December 31, 2007 is being amortized as an increase in amortization costs and included in customer rates equally over 2008 through 2010. In the absence of rate regulation, the deferral of the capital asset amortization would not have been recorded.

(vii) *Residential Unbundling*
Residential unbundling costs are related to costs incurred by TGI to develop a third-party marketer alternative for residential customers to purchase natural gas from suppliers other than TGI. The BCUC approved the deferral of these costs and the recovery of these costs over a three-year period. In the absence of rate regulation, these costs would have been expensed in the period incurred.

(viii) *Deferred Pension Costs*
Deferred pension costs are incremental pension costs arising from Newfoundland Power's 2005 Early Retirement Program that were deferred and are being amortized over a ten-year period that began on April 1, 2005, as ordered by the PUB. In the absence of rate regulation, these costs would have been expensed in 2005.

(ix) *Southern Crossing Pipeline Tax Reassessment*
The Southern Crossing Pipeline tax-reassessment deferral relates to an assessment of additional British Columbia Social Services Tax, for which TGI has filed an appeal. In 2006, the Company made a payment of $10 million pending resolution of the appeal as a good faith payment. During 2007, the assessment was reduced to $7 million and the overpayment was refunded to TGI. Depending on the success of the appeal, TGI will either be refunded the balance or, alternatively, expects to recover the costs from customers in future rates. In the absence of rate regulation, the payment would continue to be recorded as a receivable pending resolution of the appeal. Any final assessed tax, upon resolution of the appeal, would be expensed in the period in which it becomes known (Note 28).

(x) *Energy Management Costs*
FortisBC provides energy management services to promote energy efficiency programs to its customers. As required by a BCUC order, the Company has capitalized related expenditures and is amortizing these expenditures on a straight-line basis over eight years. This regulatory asset represents the unamortized balance of the energy management costs. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred.

(xi) *Other Regulatory Assets*
Other regulatory assets primarily relate to the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Maritime Electric and Caribbean Utilities. The balance is comprised of various items each individually less than $5 million. As at December 31, 2008, $32 million of the balance was approved for recovery from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2008, $7 million (December 31, 2007 – $9 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

4. *Regulatory Assets and Liabilities (cont'd)*

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xii) Future Asset Removal and Site Restoration Provision

As required by the respective regulators, this regulatory liability represents amounts collected in customer electricity rates over the life of certain utility capital assets at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric attributable to asset removal and site restoration costs that are expected to be incurred in the future. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for these future asset removal and site restoration costs, net of salvage proceeds. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred.

The regulatory liability represents the amount of expected future asset removal and site restoration costs associated with utility capital assets in service as at the balance sheet date, calculated using current amortization rates as approved by the respective regulators. Any difference between actual costs incurred and those assumed in the collected amounts, and any cumulative adjustments resulting from changes to the regulator-approved amortization rates at which these costs are collected, are reflected in the regulatory liability with the offset recorded as an adjustment to accumulated amortization.

During 2008, the amount included in amortization expense associated with the provision for future asset removal and site restoration costs was $35 million (2007 – $33 million). During 2008, actual asset removal and site restoration costs, net of salvage proceeds, were $21 million (2007 – $19 million). In the absence of rate regulation, asset removal and site restoration costs, net of salvage proceeds, would have been recognized in earnings as incurred rather than provided for over the life of the assets through amortization expense.

(xiii) Unbilled Revenue Liability

Belize Electricity and, prior to 2006, Newfoundland Power record revenue derived from electricity sales on a billed basis (Note 2). The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis is recorded on the balance sheet as a regulatory liability. Effective January 1, 2006, Newfoundland Power prospectively changed its revenue recognition policy to an accrual basis, as approved by the PUB. As a result, the $24 million cumulative difference between billed revenue as of December 31, 2005 and revenue that would have been recognized on the accrual basis was recorded as a regulatory liability. As ordered by the PUB, Newfoundland Power amortized $7 million of this regulatory liability in 2008 (2007 – $3 million). The remaining balance as at December 31, 2008 will be amortized by approximately $5 million in each of 2009 and 2010. In the absence of rate regulation, revenue would be recorded on an accrual basis and the deferral of unbilled revenue would not have been permitted. Belize Electricity's unbilled revenue liability of $6 million as at December 31, 2008 (December 31, 2007 – $5 million) is not subject to a regulatory return.

(xiv) PBR Incentive Liabilities

TGI and FortisBC's regulatory frameworks include PBR mechanisms that allow for the recovery from, or refund to, customers of a portion of certain increased or decreased costs, as compared to the forecast costs used to set customer rates. The final disposition of amounts deferred as regulatory PBR incentive assets and liabilities is determined by the sharing mechanisms with customers as approved per BCUC orders (Note 2). TGI's regulatory PBR incentive liability of $11 million is expected to be refunded to customers through reduced rates in 2009. Based on the current PBR framework, FortisBC's 2008 regulatory PBR incentive liability of $2 million has been approved by the BCUC for settlement in 2009 through a reduction in 2009 electricity revenue. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xv) Southern Crossing Pipeline Deferral

This regulatory liability represents the difference between actual revenue received from third parties for the use of the Southern Crossing Pipeline and what has been approved in revenue requirements. The balance is amortized over five years. In the absence of rate regulation, the revenue would be recognized when services are rendered.

(xvi) Fair Value of the Foreign Exchange Forward Contract

This regulatory liability captures the change in the fair value of the foreign exchange forward contract, which hedges the US dollar payments required under the LNG construction contract. In the absence of rate regulation, the change in fair value of the foreign exchange forward contract would be recorded in earnings. This regulatory deferral is not subject to a regulatory return.

(xvii) Pension Deferral

This regulatory liability represents pension surplus at FortisAlberta that has not been reflected in customer rates and will result in a reduction in future customer rates when recognized. When future customer rates are reduced, this liability will be drawn down and reflected as a reduction of pension expense. In the absence of rate regulation, the pension deferral would not be permitted and the amortization of the liability would not have occurred. This regulatory pension deferral is not subject to a regulatory return.

(xviii) *Other Regulatory Liabilities*

Other regulatory liabilities primarily relate to the Terasen Gas companies, FortisAlberta, Newfoundland Power and FortisOntario. The balance is comprised of various items each individually less than $5 million. As at December 31, 2008, $17 million of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2008, $2 million (December 31, 2007 – $7 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

Financial Statement Effect of Rate Regulation

In the absence of rate regulation and, therefore, in the absence of recording regulatory assets and liabilities as described above, the total impact on the consolidated financial statements would have been as follows:

(in millions)	**2008**	2007
Decrease in regulatory assets	**$ (349)**	$ (303)
Decrease in regulatory liabilities	**(446)**	(392)
Decrease in accumulated other comprehensive loss	**(18)**	(48)
Decrease in opening retained earnings	**(61)**	(60)
Increase in revenue	**$ 582**	$ 343
Increase in energy supply costs	**540**	340
Increase in operating expense	**79**	62
Decrease in amortization expense	**(39)**	(28)
Increase in finance charges	**–**	3
Decrease in corporate taxes	**(16)**	(15)
Net increase (decrease) in earnings	**$ 18**	$ (19)

5. Inventories

(in millions)	**2008**	2007
Gas in storage	**$ 212**	$ 195
Materials and supplies	**17**	12
	$ 229	$ 207

During 2008, inventories of $1,268 million (2007 – $559 million) were expensed and reported in energy supply costs in the consolidated statement of earnings. Inventories expensed to operating expenses were $14 million for 2008 (2007 – $13 million), which included $9 million for food and beverage costs at Fortis Properties (2007 – $8 million).

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3031, *Inventories* and inventories of $26 million were reclassified to utility capital assets from inventories on the balance sheet, as they were held for the development, construction and maintenance of other utility capital assets (January 1, 2007 – $18 million).

6. Deferred Charges and Other Assets

(in millions)	**2008**	2007
Deferred pension costs *(Note 20)*	**$ 128**	$ 114
Exploits Partnership hydroelectric generating facility capital assets *(Note 28)*	**61**	–
AESO contributions	**48**	19
Long-term accounts receivable (due 2040)	**9**	7
Deferred recoverable and project costs	**8**	7
Energy management loans	**6**	6
Corporate income tax deposit at Maritime Electric *(Note 28)*	**6**	6
Other deferred charges and assets	**13**	20
	$ 279	$ 179

6. Deferred Charges and Other Assets (cont'd)

As at December 31, 2008, the Exploits Partnership hydroelectric generating facility capital assets and deferred financing costs were reclassified to deferred charges and other assets from utility capital assets and long-term debt, respectively, as further discussed in Note 28.

AESO contributions represent payments to AESO by FortisAlberta for investment in transmission facilities that are needed for reliability or contingency planning in accordance with AESO Terms and Conditions of Service. These assets are recovered in customer rates through an AUC-approved amortization rate of approximately 3.8 per cent.

Deferred recoverable costs are amortized over the estimated remaining useful lives of the projects. Project costs are deferred until a capital project has been identified, at which time the costs are transferred to utility capital assets or income producing properties.

Energy management loans are loans to residential and general service customers for energy efficiency initiatives and related products, are interest bearing and range in terms from one year to ten years.

Other deferred charges and assets are recorded at cost and are recovered or amortized over the estimated period of future benefit.

7. Utility Capital Assets

2008 *(in millions)*	**Cost**	**Accumulated Amortization**	**Contributions in Aid of Construction (Net)**	**Regulatory Tax Basis Adjustment (Net)**	**Net Book Value**
Distribution					
Gas	**$ 2,426**	**$ (495)**	**$ (180)**	**$ –**	**$ 1,751**
Electricity	**3,948**	**(1,042)**	**(490)**	**(87)**	**2,329**
Transmission					
Gas	**1,304**	**(316)**	**(100)**	**–**	**888**
Electricity	**970**	**(252)**	**(2)**	**–**	**716**
Generation	**971**	**(280)**	**(1)**	**–**	**690**
Assets under construction	**317**	**–**	**(11)**	**–**	**306**
Other	**1,090**	**(390)**	**(13)**	**–**	**687**
	$ 11,026	**$ (2,775)**	**$ (797)**	**$ (87)**	**$ 7,367**

2007 *(in millions)*	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	$ 2,233	$ (364)	$ (174)	$ –	$ 1,695
Electricity	3,542	(961)	(463)	(91)	2,027
Transmission					
Gas	1,277	(286)	(102)	–	889
Electricity	873	(224)	–	–	649
Generation	914	(240)	–	–	674
Assets under construction	195	–	–	–	195
Other	970	(337)	(14)	–	619
	$ 10,004	$ (2,412)	$ (753)	$ (91)	$ 6,748

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electricity distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electricity transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires and conductors, substations, support structures and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

The cost of utility capital assets under capital lease as at December 31, 2008 was $56 million (December 31, 2007 – $51 million) and related accumulated amortization was $24 million (December 31, 2007 – $19 million).

8. Income Producing Properties

2008

(in millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
Buildings	**$ 485**	**$ (51)**	**$ 434**
Land	**61**	**–**	**61**
Tenant inducements	**24**	**(14)**	**10**
Equipment	**56**	**(23)**	**33**
Construction in progress	**3**	**–**	**3**
	$ 629	**$ (88)**	**$ 541**

2007

(in millions)	Cost	Accumulated Amortization	Net Book Value
Buildings	$ 469	$ (42)	$ 427
Land	54	–	54
Tenant inducements	22	(13)	9
Equipment	46	(18)	28
Construction in progress	1	–	1
	$ 592	$ (73)	$ 519

The cost of income producing property assets under capital lease as at December 31, 2008 was $1 million (December 31, 2007 – $6 million) and related accumulated amortization was $0.1 million (December 31, 2007 – $4 million).

9. Goodwill

(in millions)	**2008**	2007
Balance, beginning of year	**$ 1,544**	$ 661
Acquisition of Terasen *(Note 21)*	**(4)**	907
Reversal of restructuring accrual	**–**	(2)
Step-acquisition of Caribbean Utilities	**6**	–
Foreign currency translation impacts	**29**	(22)
Balance, end of year	**$ 1,575**	$ 1,544

During 2008, the Terasen Gas companies recognized the benefit of tax losses, which related to periods prior to the Corporation's ownership of Terasen resulting in a reduction in goodwill.

Goodwill associated with the acquisitions of Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars as the reporting currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

10. Long-Term Debt and Capital Lease Obligations

(in millions)	Maturity Date	2008	2007
Regulated Utilities			
Terasen Gas Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2007 – 10.71%)	2015–2016	**$ 275**	$ 275
Unsecured Debentures –			
6.29% weighted average fixed rate (2007 – 6.44%)	2009–2038	**1,380**	1,068
Government loan *(Note 27)*	2009	**8**	6
Obligations under capital leases	2012	**10**	9
FortisAlberta			
Senior Unsecured Debentures –			
5.61% weighted average fixed rate (2007 – 5.57%)	2014–2047	**709**	610
FortisBC			
Secured Debentures –			
9.28% weighted average fixed rate (2007 – 9.31%)	2009–2023	**44**	45
Unsecured Debentures –			
6.06% weighted average fixed rate (2007 – 6.06%)	2009–2047	**445**	445
Obligation under capital lease	2032	**26**	26
Newfoundland Power			
Secured First Mortgage Sinking Fund Bonds –			
7.84% weighted average fixed rate (2007 – 7.84%)	2014–2037	**409**	414
Maritime Electric			
Secured First Mortgage Bonds –			
8.10% weighted average fixed rate (2007 – 9.43%)	2010–2038	**152**	92
FortisOntario			
Senior Unsecured Notes – 7.09% fixed rate	2018	**52**	52
Belize Electricity			
Secured:			
US RBTT Merchant Bank loan – 5.75% to 8.15% fixed rate	2010–2012	**5**	6
Unsecured:			
BZ Debentures –			
10.35% weighted average fixed rate (2007 – 10.36%)	2012–2027	**42**	33
Other loans – 5.81% weighted average fixed rate (2007 – 5.73%)	2009–2015	**11**	11
Other variable interest rate loans	2010–2015	**18**	10
Caribbean Utilities			
Unsecured Senior Loan Notes –			
6.04% weighted average fixed rate (2007 – 6.09%)	2009–2022	**204**	177
Fortis Turks and Caicos			
Unsecured:			
US Scotiabank (Turks and Caicos) Ltd. loan –			
3.91% weighted average fixed and variable rate (2007 – 3.88%)	2013–2016	**14**	13
US First Caribbean International Bank loan – 5.65% fixed rate	2015	**4**	3
Non-Regulated – Fortis Generation			
Secured:			
Mortgage – 9.44% fixed rate	2013	**5**	5
Term loan – 7.55% fixed rate (non-recourse to Fortis Inc.) *(Note 28)*	2028	**61**	62

(in millions)	Maturity Date	2008	2007
Non-Regulated – Fortis Properties			
Secured:			
First mortgages –			
7.02% weighted average fixed rate (2007 – 7.02%)	2010–2017	**$ 212**	$ 220
Senior notes – 7.32% fixed rate	2019	**16**	17
Unsecured:			
Obligation under capital lease	2008	**–**	2
Non-revolving variable interest rate credit facilities	2009–2010	**7**	7
Corporate – Fortis and Terasen			
Unsecured:			
Debentures –			
6.36% weighted average fixed rate (2007 – 6.33%)	2010–2014	**230**	436
US Senior Notes –			
6.23% weighted average fixed rate (2007 – 6.23%)	2014–2037	**426**	347
US Subordinated Convertible Debentures –			
5.50% weighted average fixed rate (2007 – 5.66%)	2016	**44**	45
Capital Securities – 8.00% fixed rate	2040	**125**	126
Long-term classification of credit-facility borrowings *(Note 26)*		**224**	530
Total long-term debt and capital lease obligations		**5,158**	5,092
Less: Deferred financing costs		**(34)**	(33)
Less: Current installments of long-term debt and capital lease obligations		**(240)**	(436)
		$ 4,884	$ 4,623

Certain of the long-term debt instruments held by the Corporation and its subsidiaries are secured as identified in the table above. When security is provided, it is typically a fixed or floating charge on the specific assets of the company to which the long-term debt is associated.

The purchase money mortgages of the Terasen Gas companies are secured equally and rateably by a first fixed and specific mortgage and charge on TGI's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be used is limited to $425 million.

Repayment of Long-Term Debt and Capital Lease Obligations

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

Year	$ millions
2009	240
2010	219
2011	104
2012	254
2013	85
Thereafter	4,256

Regulated Utilities

FortisBC has a capital lease obligation with respect to the operation of the Brilliant Terminal Station. Future minimum lease payments associated with this capital lease obligation are approximately $3 million per year over the remaining term of the lease agreement to 2032. The capital lease obligation bears interest at a composite rate of 8.62 per cent.

Belize Electricity's unsecured debentures can be called by the Company at any time after certain dates until maturity by giving holders not more than 60 days' nor less than 30 days' written notice, and are repayable at the option of the holders at any time on or after certain dates by giving 12 months' written notice to Belize Electricity. Redemption by agreement between Belize Electricity and the debenture holders at any time is also allowed.

10. Long-Term Debt and Capital Lease Obligations (cont'd)

Corporate – Fortis and Terasen

Of the unsecured debentures, $100 million are redeemable at the option of Fortis at a price calculated as the greater of the principal amount to be redeemed and an amount equal to the net present value of interest and principal based on the Government of Canada Yield, plus a premium ranging from 0.43% to 0.87%, together with accrued and unpaid interest.

The unsecured subordinated convertible debentures, due 2016, are redeemable by Fortis at par at any time on or after November 7, 2011 and are convertible, at the option of the holder, into the Corporation's common shares at $35.46 per share (US$29.11 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The unsecured subordinated convertible debentures are being accounted for in accordance with their substance and are presented in the financial statements in their component parts. The liability and equity components are classified separately on the consolidated balance sheet and are measured at their respective fair values at the time of issue. The equity portion of convertible debentures was $6 million as at December 31, 2008 (December 31, 2007 – $6 million).

Terasen may elect to defer payment on the 8.00% capital securities and settle such deferred payments in either cash or common shares of the Company and has the option to settle principal at maturity through the issuance of common shares of the Company. The securities are also exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90 per cent of the market price, subject to the right of the Company to redeem the securities for cash at par as of the same date.

11. Deferred Credits

(in millions)	**2008**	2007
OPEB plan liabilities *(Note 20)*	**$ 129**	$ 112
Defined benefit liabilities *(Note 20)*	**34**	32
Deferred gains on the sale of natural gas transmission and distribution assets	**46**	50
Deferred payment	**43**	40
Other deferred credits	**25**	27
	$ 277	$ 261

The deferred gains on the sale of natural gas transmission and distribution assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $71 million on combined cash proceeds of $141 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 27.

The deferred payment resulted from Terasen's acquisition of TGVI, effective January 1, 2002. The deferred payment has a face value of $52 million but was discounted at May 17, 2007 to its present value. At December 31, 2008, its present value was $43 million (December 31, 2007 – $40 million). The payment is due on December 31, 2011 or sooner if TGVI realizes revenue from transportation revenue contracts to serve power-generating plants that may be constructed in TGVI's service area. If any part of the deferred payment is paid prior to December 31, 2011, the difference between the payment and the carrying value of the debt will be treated as contingent consideration for the acquisition of TGVI and will be added to the cost of the purchase at that time.

Other deferred credits primarily include customer deposits, DSU and PSU liabilities and unfunded defined contribution pension liabilities.

12. Non-Controlling Interest

(in millions)	**2008**	2007
Caribbean Utilities	**$ 92**	$ 67
Belize Electricity	**44**	38
Preference shares of Newfoundland Power	**7**	7
Exploits Partnership	**2**	3
	$ 145	$ 115

13. Preference Shares

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value

(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		**2008**		2007	
	Classification	**Number of Shares**	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
First Preference Shares, Series C	Debt	**5,000,000**	**$ 123**	5,000,000	$ 123
First Preference Shares, Series E	Debt	**7,993,500**	**197**	7,993,500	197
Total classified as debt		**12,993,500**	**$ 320**	12,993,500	$ 320
First Preference Shares, Series F	Equity	**5,000,000**	**$ 122**	5,000,000	$ 122
First Preference Shares, Series G	Equity	**9,200,000**	**225**	–	–
Total classified as equity		**14,200,000**	**$ 347**	5,000,000	$ 122

First Preference Shares Classified as Debt

As the First Preference Shares, Series C and Series E are convertible at the option of the shareholder into a variable number of common shares of the Corporation based on a market-related price of such common shares, they meet the definition of financial liabilities and, therefore, are classified as long-term liabilities with associated dividends classified as finance charges.

The First Preference Shares, Series C and Series E are entitled to receive fixed cumulative preferential cash dividends at rates of $1.3625 and $1.2250 per share per annum, respectively.

On or after June 1, 2010 and 2013, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series C and Series E, respectively, in whole at any time or in part from time to time, at prices ranging from $25.75 to $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

On or after June 1, 2010 and 2013, the Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series C and Series E, respectively, into fully paid and freely tradable common shares of the Corporation. The number of common shares into which each preference share may be so converted will be determined by dividing the then-applicable redemption price per first preference share, together with all accrued and unpaid dividends, by the greater of $1.00 and 95 per cent of the then-current market price of the common shares at such time.

On or after September 1, 2013 and 2016, each First Preference Share, Series C and Series E, respectively, will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradable common shares of the Corporation determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 and 95 per cent of the then-current market price of the common shares. If a holder of First Preference Shares, Series C and Series E elects to convert any of such shares into common shares, the Corporation can redeem such first preference shares for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares Classified as Equity

In May 2008, the Corporation issued 8 million 5.25% Cumulative Redeemable Five-Year Fixed-Rate Reset First Preference Shares, Series G ("First Preference Shares, Series G") and in June 2008 issued an additional 1.2 million First Preference Shares, Series G, following the exercise in full of an over-allotment option in connection with the offering of the 8 million First Preference Shares, Series G. The 9.2 million First Preference Shares, Series G were issued at $25.00 per share for net after-tax proceeds of $225 million.

As the First Preference Shares, Series F and Series G are not redeemable at the option of the shareholder, they are classified as equity and the associated dividends are deducted on the consolidated statement of earnings immediately before arriving at net earnings applicable to common shares.

The First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends in the amount of $1.2250 per share per annum. The First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends in the amount of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after this date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying the $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%.

13. Preference Shares (cont'd)

First Preference Shares Classified as Equity (cont'd)

On or after December 1, 2011, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series F, in whole at any time or in part from time to time, at prices ranging from $26.00 to $25.00 per share plus all accrued and unpaid dividends. On September 1, 2013, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

14. Common Shares

Authorized: an unlimited number of common shares without nominal or par value.

Issued and Outstanding	**2008**		2007	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Common shares	**169,190,917**	**$ 2,449**	155,521,313	$ 2,126

Common shares issued during the year were as follows:

	2008		2007	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Balance, Beginning of Year	**155,521,313**	**$ 2,126**	104,091,542	$ 829
Public Offering	**11,700,000**	**291**	5,170,000	146
Public Offering – Conversion of Subscription Receipts	**–**	**–**	44,275,000	1,119
Conversion of Debentures	**1,041,871**	**11**	882,626	9
Consumer Share Purchase Plan	**88,686**	**2**	79,463	3
Dividend Reinvestment Plan	**230,601**	**6**	203,763	5
Employee Share Purchase Plan	**272,095**	**7**	240,578	6
Stock Option Plans	**336,351**	**6**	578,341	9
Balance, End of Year	**169,190,917**	**$ 2,449**	155,521,313	$ 2,126

In December 2008, Fortis issued 11.7 million common shares for $25.65 per common share. The common share issue resulted in gross proceeds of approximately $300 million, or approximately $291 million net of after-tax expenses.

During 2008, holders of the Corporation's former 6.75% and 5.50% unsecured subordinated convertible debentures converted approximately US$11 million of the debentures into approximately 1.0 million common shares of the Corporation.

In January 2007, Fortis issued 5.17 million common shares for $29.00 per common share. The common share issue resulted in gross proceeds of approximately $150 million, or approximately $146 million net of after-tax expenses.

In March 2007, to finance a significant portion of the net cash purchase price of Terasen, the Corporation sold approximately 44.3 million Subscription Receipts at $26.00 each for gross proceeds of approximately $1.15 billion. Upon closing of the acquisition of Terasen on May 17, 2007, each Subscription Receipt was exchanged, without payment of additional consideration, for one common share of Fortis. Each Subscription Receipt holder also received a cash payment of $0.21 per Subscription Receipt, which was an amount equal to the dividend declared per common share of Fortis to holders of record as of May 4, 2007. The net proceeds to the Corporation upon conversion of the Subscription Receipts were approximately $1.12 billion net of after-tax expenses.

During 2007, holders of the Corporation's former 6.75% and 5.50% unsecured subordinated convertible debentures converted approximately US$9 million of the US$20 million debentures into approximately 0.9 million common shares of the Corporation.

As at December 31, 2008, 9.8 million (December 31, 2007 – 6.2 million) common shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans. During 2008, an additional 5 million common shares were reserved under the dividend reinvestment plan in accordance with an enhancement made to the plan. The Corporation amended and restated its dividend reinvestment plan to provide a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009.

As at December 31, 2008, common shares reserved for issuance under the terms of the Corporation's convertible debentures and preference shares were 1.4 million and 26 million, respectively (December 31, 2007 – 2.4 million and 26 million, respectively).

As at December 31, 2008, $3 million (December 31, 2007 – $3 million) of common share equity had not been fully paid relating to amounts outstanding under employee share purchase and executive stock option loans.

Earnings per Common Share

The Corporation calculates earnings per common share on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 157.4 million for 2008 and 137.6 million for 2007.

Diluted earnings per common share are calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

Earnings per common share are as follows:

	2008			2007		
	Earnings *(in millions)*	**Weighted Average Shares** *(in millions)*	**Earnings per Common Share**	Earnings *(in millions)*	Weighted Average Shares *(in millions)*	Earnings per Common Share
Basic Earnings per Common Share	**$ 245**	**157.4**	**$ 1.56**	$ 193	137.6	$ 1.40
Effect of Potential Dilutive Securities:						
Subscription Receipts[1]	**–**	**–**		–	7.8	
Stock Options	**–**	**1.0**		–	1.2	
Preference Shares *(Notes 13 and 17)*	**17**	**13.9**		17	11.5	
Convertible Debentures	**2**	**1.4**		3	2.8	
	264	**173.7**		213	160.9	
Deduct Anti-Dilutive Impacts:						
Convertible Debentures	**–**	**–**		(2)	(1.4)	
Diluted Earnings per Common Share	**$ 264**	**173.7**	**$ 1.52**	$ 211	159.5	$ 1.32

[1] Dilution relates to the period the Subscription Receipts were outstanding from March 15, 2007 to May 16, 2007, prior to their conversion into common shares.

15. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2008, the Corporation had the following stock option plans: 2006 Plan, 2002 Plan and Executive Stock Option Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to ultimately replace the Executive and the former Directors' Stock Option Plans. The Executive Stock Option Plan will cease to exist when all outstanding options are exercised or expire in or before 2011. The 2006 Plan was approved at the May 2, 2006 Annual Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options are exercised or expire in or before 2016. The Corporation has ceased to grant options under the Executive Stock Option Plan and 2002 Plan and all new options are being granted under the 2006 Plan.

Options granted under the 2006 Plan have a maximum term of seven years and expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant. Directors are not eligible to receive grants of options under the 2006 Plan.

Number of Options:	**2008**	2007
Options outstanding, beginning of year	**3,691,771**	3,550,055
Granted	**827,504**	754,800
Cancelled	**(42,462)**	(34,743)
Exercised	**(336,351)**	(578,341)
Options outstanding, end of year	**4,140,462**	3,691,771
Options vested, end of year	**2,279,240**	1,901,811

15. Stock-Based Compensation Plans (cont'd)

Weighted Average Exercise Prices:	2008	2007
Options outstanding, beginning of year	**$ 18.86**	$ 16.11
Granted	**28.27**	27.75
Cancelled	**24.20**	22.43
Exercised	**14.48**	13.35
Options outstanding, end of year	**21.04**	18.86

Details of stock options outstanding and vested as at December 31, 2008 are as follows:

Number of Options Outstanding	Number of Options Vested	Exercise Price	Expiry Date
97,842	97,842	$ 9.57	2011
166,473	166,473	$ 12.03	2012
472,393	472,393	$ 12.81	2013
572,528	572,528	$ 15.28	2014
10,000	10,000	$ 15.23	2014
32,793	32,793	$ 14.55	2014
637,902	457,808	$ 18.40	2015
28,000	21,000	$ 18.11	2015
17,500	9,065	$ 20.82	2015
556,615	256,072	$ 22.94	2016
596,232	149,058	$ 28.19	2014
136,832	34,208	$ 25.76	2014
815,352	–	$ 28.27	2015
4,140,462	2,279,240		

The weighted average exercise price of stock options vested as at December 31, 2008 was $16.81.

In February 2008, the Corporation granted 827,504 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of $28.27 immediately preceding the date of grant. The fair value of each option granted was $4.76 per option.

The fair value was estimated on the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

Dividend yield *(%)*	2.90
Expected volatility *(%)*	20.7
Risk-free interest rate *(%)*	3.92
Weighted average expected life *(years)*	4.5

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 and 2006 Plans. Using the fair value method, the compensation expense is amortized over the four-year vesting period of the options granted. Under the fair value method, compensation expense associated with stock options was $3 million for the year ended December 31, 2008 (2007 – $2 million).

Directors' DSU Plan

In 2004, the Corporation introduced the Directors' DSU Plan as an optional vehicle for directors to elect to receive credit for their annual retainer to a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Effective 2006, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation.

Number of DSUs:	2008	2007
DSUs outstanding, beginning of year	**69,722**	46,959
Granted	**27,224**	20,859
Granted – notional dividends reinvested	**3,671**	1,904
DSUs outstanding, end of year	**100,617**	69,722

For the year ended December 31, 2008, expense of $0.2 million (2007 – $0.8 million) was recorded in relation to the DSU Plan.

PSU Plan

In 2004, the Corporation introduced the PSU Plan, which is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer ("CEO") of the Corporation. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation.

Number of PSUs:	2008	2007
PSUs outstanding, beginning of year	**67,615**	66,845
Granted	**32,940**	19,570
Granted – notional dividends reinvested	**3,011**	1,883
PSUs paid out	**(18,019)**	(20,683)
PSUs outstanding, end of year	**85,547**	67,615

In March 2008, 18,019 PSUs were paid out to the President and CEO of the Corporation at $28.36 per PSU for a total of approximately $0.5 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2005, and the President and CEO satisfying the payment requirements as determined by the Human Resources Committee of the Board of Directors of Fortis.

For the year ended December 31, 2008, expense of $0.6 million (2007 – $0.6 million) was recorded in relation to the PSU Plan.

16. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss includes unrealized foreign currency translation gains and losses, net of hedging activities, gains and losses on cash flow hedging activities and gains and losses on discontinued cash flow hedging activities, as discussed in Note 2.

	2008		
(in millions)	Opening balance January 1	Net change	**Ending balance December 31**
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	**$ (82)**	**$ 36**	**$ (46)**
Losses on derivative instruments designated as cash flow hedges, net of tax	**(1)**	**–**	**(1)**
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	**(5)**	**–**	**(5)**
Accumulated other comprehensive loss	**$ (88)**	**$ 36**	**$ (52)**

	2007			
(in millions)	Opening balance January 1	Transition amount January 1	Net change	Ending balance December 31
Unrealized foreign currency translation losses, net of hedging activities and tax	$ (51)	$ –	$ (31)	$ (82)
Losses on derivative instruments designated as cash flow hedges, net of tax	–	(1)	–	(1)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	–	(5)	–	(5)
Accumulated other comprehensive loss	$ (51)	$ (6)	$ (31)	$ (88)

16. Accumulated Other Comprehensive Loss (cont'd)

During 2008, unrealized foreign currency translation gains of $115 million (2007 – losses of $70 million) were recorded in accumulated other comprehensive loss related to the Corporation's net investment in foreign currency-denominated self-sustaining foreign operations. These unrealized foreign currency translation gains were partially offset by the effective portion of unrealized after-tax losses of $79 million (2007 – after-tax gains of $39 million) related to the translation of corporately held US dollar-denominated long-term debt designated as a foreign currency risk hedge. There was no ineffective portion.

As at January 1, 2007, in accordance with the transitional provisions of CICA Handbook Section 3865, *Hedges*, a net loss of $5 million associated with unamortized deferred gain and loss balances related to previously cancelled swap agreements was reclassified to accumulated other comprehensive loss. The deferred gain and loss balances are amortized to comprehensive income on a straight-line basis over the life of the related debt.

On January 1, 2007, as required upon initial application of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*, all adjustments to the carrying amount of financial instruments were recognized as an adjustment to the opening balance of accumulated other comprehensive loss. The Corporation was not required to remeasure any assets or liabilities upon adoption of Section 3855; therefore, no adjustments were made to the opening balance of retained earnings.

17. Finance Charges

(in millions)	**2008**	2007
Interest – Long-term debt and capital lease obligations	**$ 329**	$ 266
– Short-term borrowings	**32**	27
AFUDC *(Note 2)*	**(13)**	(8)
Interest earned	**(2)**	(4)
Unrealized foreign exchange loss on long-term debt	**–**	1
Dividends on preference shares *(Notes 13 and 14)*	**17**	17
	$ 363	$ 299

18. Gain on Sale of Property

In December 2007, TGI sold surplus land resulting in an $8 million ($7 million after-tax) gain on the sale.

19. Corporate Taxes

Corporate taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory tax rate to earnings before corporate taxes and non-controlling interest. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	**2008**	2007
Combined Canadian federal and provincial statutory income tax rate	**33.5%**	36.1%
Statutory income tax rate applied to earnings before corporate taxes and non-controlling interest	**$ 113**	$ 90
Preference share dividends	**6**	6
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(12)**	(18)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(6)**	(3)
Items capitalized for accounting but expensed for income tax purposes	**(33)**	(21)
Difference between capital cost allowance ("CCA") and other deductions claimed for income tax purposes and amounts recorded for accounting purposes[(1)]	**5**	(12)
Impact of reduction in income tax rates on future income taxes	**–**	(6)
Québec Tax Trust and other tax settlements – Terasen[(2)]	**(7)**	2
Maritime Electric tax reassessment	**–**	3
Pension costs	**(2)**	(2)
Other	**1**	(3)
Corporate taxes	**$ 65**	$ 36
Effective tax rate	**19.3%**	14.4%

(1) During 2008, CCA deductions at FortisAlberta were lower than amortization expense. However, during 2007, CCA deductions at FortisAlberta were higher than amortization expense. The higher CCA deductions in 2007 were required to offset taxable income on the sale, in 2007, of the 2006 AESO charges deferral receivable balance.

(2) During 2008, Terasen reached a settlement with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of amended Québec tax legislation. The legislation was passed in 2006 for the purpose of challenging certain interprovincial Canadian tax structures. As a result of the settlement, Terasen recorded an approximate $7.5 million tax reduction in 2008.

The components of the provision for corporate taxes are as follows:

(in millions)	**2008**	2007
Canadian		
Current taxes	**$ 47**	$ 33
Future income taxes	**16**	–
	63	33
Foreign		
Current taxes	**4**	3
Future income taxes	**(2)**	–
	2	3
Corporate taxes	**$ 65**	$ 36

19. Corporate Taxes (cont'd)

Future income taxes are provided for temporary differences. Future income tax assets and liabilities are comprised of the following:

(in millions)	**2008**	2007
Future income tax liability (asset)		
Income producing properties	**$ 26**	$ 22
Utility capital assets	**17**	13
ECAM	**16**	10
Other regulatory assets and liabilities	**2**	2
Intangible assets	**3**	5
Employee future benefits	**(14)**	(14)
Loss carryforwards	**(11)**	(10)
Share issue and debt financing costs	**(14)**	(16)
Unrealized foreign currency translation (losses) gains on long-term debt	**(5)**	8
Other	**2**	5
Net future income tax liability	**$ 22**	$ 25
Current future income tax liability	**$ 15**	$ 7
Long-term future income tax asset	**(54)**	(37)
Long-term future income tax liability	**61**	55
Net future income tax liability	**$ 22**	$ 25

As at December 31, 2008, the Corporation had approximately $104 million (December 31, 2007 – $51 million) in non-capital and capital loss carryforwards, of which $8 million (December 31, 2007 – $3 million) in capital losses has not been recognized in the financial statements. The non-capital loss carryforwards expire between 2009 and 2028.

20. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group RRSPs for its employees. The Corporation, Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer OPEB plans for qualifying employees.

For the defined benefit pension arrangements, the accrued pension benefit obligation and the market-related value or fair value of plan assets are measured for accounting purposes as at December 31 of each year for the Corporation, Terasen Gas companies, Newfoundland Power and Caribbean Utilities commencing December 2008 (2007 – measured as at April 30), and as at September 30 of each year for FortisAlberta, FortisBC and FortisOntario. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2007 for FortisAlberta and FortisBC; as of December 31, 2006 for FortisOntario; as of December 31, 2005 for the Corporation and Newfoundland Power; and as of December 31, 2008 for Caribbean Utilities. For the Terasen Gas companies, the most recent actuarial valuations of the pension plans for funding purposes were between December 31, 2005 and December 31, 2007. The next required valuations will be, at the latest, three years from the date of the most recent actuarial valuation for each company.

Actuarial valuations of the pension plans for funding purposes are currently being completed as of December 31, 2008 for the Corporation, Newfoundland Power and one of the pension plans at the Terasen Gas companies. The valuations are expected to be completed in 2009.

The Corporation's consolidated defined benefit pension plan asset allocation is as follows:

Plan assets as at December 31

(%)	**2008**	2007
Canadian equities	**42**	50
Fixed income	**44**	38
Foreign equities	**8**	8
Real estate	**6**	4
	100	100

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension plans and their respective funded or unfunded status:

(in millions)	**2008** Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)	2007 Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
Terasen Gas companies	**$ 253**	**$ 227**	**$ (26)**	$ 254	$ 261	$ 7
FortisAlberta	**22**	**18**	**(4)**	23	20	(3)
FortisBC	**117**	**96**	**(21)**	122	105	(17)
Newfoundland Power	**190**	**212**	**22**	236	260	24
FortisOntario	**21**	**19**	**(2)**	23	21	(2)
Caribbean Utilities	**6**	**3**	**(3)**	5	3	(2)
Fortis Inc.	**4**	**4**	**–**	4	4	–
Total	**$ 613**	**$ 579**	**$ (34)**	$ 667	$ 674	$ 7

	Defined Benefit Pension Plans Funded		**Supplementary Defined Benefit Plans Unfunded**		**OPEB Plans Unfunded**	
(in millions)	**2008**	2007	**2008**	2007	**2008**	2007
Change in accrued benefit obligation						
Balance, beginning of year	**$ 667**	$ 413	**$ 44**	$ 17	**$ 189**	$ 109
Liability associated with acquisitions	**–**	248	**–**	27	**–**	79
Current service costs	**16**	12	**1**	1	**4**	4
Employee contributions	**8**	6	**–**	–	**–**	–
Interest costs	**36**	29	**2**	2	**10**	8
Benefits paid	**(32)**	(25)	**(2)**	(2)	**(4)**	(4)
Actuarial gain	**(80)**	(16)	**(4)**	(1)	**(30)**	(8)
Plan amendments	**(2)**	–	**–**	–	**–**	1
Balance, end of year	**$ 613**	$ 667	**$ 41**	$ 44	**$ 169**	$ 189
Change in value of plan assets						
Balance, beginning of year	**$ 674**	$ 390	**$ –**	$ –	**$ –**	$ –
Assets associated with acquisitions	**–**	256	**–**	–	**–**	–
Actual (loss) return on plan assets	**(92)**	26	**–**	–	**–**	–
Benefits paid	**(32)**	(25)	**(2)**	(2)	**(4)**	(4)
Employee contributions	**8**	6	**–**	–	**–**	–
Employer contributions	**21**	21	**2**	2	**4**	4
Balance, end of year	**$ 579**	$ 674	**$ –**	$ –	**$ –**	$ –
Funded status						
(Deficit) surplus, end of year	**$ (34)**	$ 7	**$ (41)**	$ (44)	**$ (169)**	$ (189)
Unamortized net actuarial loss (gain)	**152**	95	**(1)**	3	**26**	61
Unamortized past service costs	**7**	10	**1**	1	**(2)**	(2)
Unamortized transitional obligation	**7**	7	**2**	2	**15**	18
Plan amendment	**–**	–	**–**	–	**1**	–
Employer contributions after measurement date	**1**	1	**–**	–	**–**	–
Accrued benefit asset (liability), end of year	**$ 133**	$ 120	**$ (39)**	$ (38)	**$ (129)**	$ (112)
Deferred pension costs *(Note 6)*	**$ 135**	$ 121	**$ (7)**	$ (7)	**$ –**	$ –
Defined benefit liabilities *(Note 11)*	**(2)**	(1)	**(32)**	(31)	**–**	–
OPEB plan liabilities *(Note 11)*	**–**	–	**–**	–	**(129)**	(112)
	$ 133	$ 120	**$ (39)**	$ (38)	**$ (129)**	$ (112)

20. Employee Future Benefits (cont'd)

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	**2008**	2007	**2008**	2007	**2008**	2007
Significant assumptions						
Discount rate during the year *(%)*	**5.25–5.60**	5.00–5.25	**5.25–5.75**	5.00–5.25	**5.25–5.75**	5.00–5.25
Discount rate as at December 31 *(%)*	**6.00–7.50**	5.25–5.60	**6.25–7.50**	5.25–5.75	**6.00–7.50**	5.25–5.75
Expected long-term rate of return on plan assets *(%)*	**3.00–7.50**	6.50–7.50	**–**	–	**–**	–
Rate of compensation increase *(%)*	**3.00–5.00**	3.50–4.25	**3.19–5.00**	3.77–4.25	**3.50–5.00**	3.50–4.25
Health-care cost trend increase as at December 31 *(%)*	**–**	–	**–**	–	**4.41–9.00**	4.50–10.00
Expected average remaining service life of active employees *(years)*	**5–12**	7–13	**4–12**	3–13	**9–15**	10–16
Components of net benefit expense						
Current service costs	**$ 16**	$ 12	**$ 1**	$ 1	**$ 4**	$ 4
Interest costs	**36**	29	**2**	2	**10**	8
Actual loss (return) on plan assets	**92**	(26)	**–**	–	**–**	–
Actuarial gain	**(80)**	(16)	**(4)**	(1)	**(30)**	(8)
Plan amendments	**(2)**	–	**–**	–	**–**	1
Costs arising in the year	**62**	(1)	**(1)**	2	**(16)**	5
Differences between costs arising and costs recognized in the year in respect of:						
Return on plan assets	**(141)**	(11)	**–**	–	**–**	–
Actuarial gain	**84**	20	**4**	1	**34**	11
Past service costs	**3**	2	**1**	–	**–**	–
Special termination benefits	**–**	1	**–**	–	**–**	–
Transitional obligation and amendments	**–**	1	**–**	–	**3**	2
Regulatory adjustment	**1**	–	**–**	–	**(7)**	(7)
Net benefit expense	**$ 9**	$ 12	**$ 4**	$ 3	**$ 14**	$ 11

For 2008, the effects of changing the health-care cost trend rate by 1 per cent are as follows:

(in millions)	1 per cent increase in rate	1 per cent decrease in rate
Increase (decrease) in accrued benefit obligation	**$ 22**	**$ (16)**
Increase (decrease) in current service and interest costs	**2**	**(2)**

The following table provides the sensitivities associated with a 100 basis point move in the expected long-term rate of return on pension plan assets and the discount rate on 2008 net defined benefit pension expense, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation.

Increase (Decrease) *(in millions)*	Net Benefit Expense	Accrued Benefit Asset	Accrued Benefit Liability	Accrued Benefit Obligation
Impact of increasing the rate of return assumption by 100 basis points	$ (7)	$ 7	$ –	$ –
Impact of decreasing the rate of return assumption by 100 basis points	7	(7)	–	–
Impact of increasing the discount rate assumption by 100 basis points	(3)	2	(1)	(57)
Impact of decreasing the discount rate assumption by 100 basis points	10	(8)	1	67

During 2008, the Corporation expensed $11 million (2007 – $10 million) related to defined contribution pension plans.

21. Business Acquisitions

2008

Fairmont Newfoundland Hotel

In November 2008, Fortis Properties purchased the Fairmont Newfoundland hotel for an aggregate cash purchase price of approximately $22 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the results of operations have been consolidated in the financial statements of Fortis commencing November 2008.

The purchase price allocation to assets, based on their fair values, was as follows:

(in millions)	**Total**
Fair value assigned to net assets:	
Income producing properties	**$ 22**

2007

a. Terasen

On May 17, 2007, Fortis acquired all of the issued and outstanding common shares of Terasen for aggregate consideration of approximately $3.7 billion. The net cash purchase price of approximately $1.25 billion, including acquisition costs, was primarily financed through proceeds from the issuance of common equity, with the remaining $125 million of the net cash purchase price being financed, on an interim basis, through drawings on the Corporation's committed credit facility.

Terasen owns and operates a gas distribution business carried on by TGI, TGVI and TGWI. Terasen is the principal natural gas distributor in British Columbia.

The acquisition has been accounted for using the purchase method, whereby the consolidated results of Terasen have been included in the consolidated financial statements of Fortis commencing May 17, 2007. The financial results of the Terasen Gas companies have been included in the Regulated Gas Utilities – Canadian segment, while net expenses of non-regulated Terasen corporate-related activities, Terasen's 30 per cent investment in non-regulated CWLP and Terasen's 100 per cent investment in non-regulated TES have been included in the Corporate and Other segment. The Terasen Gas companies are regulated under traditional cost of service. The determination of revenue and earnings is based on regulated rates of return that are applied to historic values which do not change with a change of ownership. Therefore, for substantially all of the individual assets and liabilities associated with the Terasen Gas companies, no fair market value adjustments were recorded as part of the purchase price because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. Accordingly, the book value of substantially all of the assets and liabilities of the Terasen Gas companies has been assigned as fair value for the purchase price allocation. Substantially all of the fair market value adjustments, including intangibles, recorded as part of the purchase price allocation are related to non-regulated Terasen and its non-regulated investments.

The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition. The amount of the purchase price assignable to goodwill is entirely associated with the regulated Terasen Gas companies. Approximately $40 million of goodwill is deductible for tax purposes. Of the $11 million in intangible assets, $10 million was assigned as the value associated with customer contracts at CWLP. Approximately $1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization.

During 2008, the Terasen Gas companies recognized the benefit of tax losses, which related to periods prior to the Corporation's ownership of Terasen, resulting in a $6 million reduction in goodwill. Partially offsetting the above was a final purchase adjustment of $2 million, which increased goodwill.

21. Business Acquisitions (cont'd)

a. Terasen (cont'd)

(in millions)	Total
Fair value assigned to net assets:	
Utility capital assets	$ 2,768
Current assets	361
Goodwill	903
Intangibles	11
Long-term regulatory assets	69
Other assets	42
Current liabilities	(355)
Assumed short-term indebtedness	(275)
Assumed long-term debt (including current portion)	(2,077)
Long-term regulatory liabilities	(29)
Other liabilities	(165)
	1,253
Cash	3
	$ 1,256

b. Delta Regina

In August 2007, Fortis Properties purchased the Delta Regina, comprising the Delta Regina hotel, the Saskatchewan Trade and Convention Centre, 52,000 square feet of commercial office space and a parking garage in Regina, Saskatchewan for an aggregate cash purchase price of approximately $50 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the results of operations have been consolidated in the financial statements of Fortis commencing August 2007.

The purchase price allocation to assets, based on their fair values, was as follows:

(in millions)	Total
Fair value assigned to net assets:	
Income producing properties	$ 50

22. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2008 *($ millions)*	**Terasen Gas Companies – Canadian**[1]	Fortis Alberta	Fortis BC	NF Power	Other Canadian[2]	**Total Electric Canadian**	**Electric Caribbean**[3]	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**1,902**	300	237	517	262	**1,316**	**408**	**82**	**207**	**26**	**(38)**	**3,903**
Energy supply costs	**1,268**	–	68	337	177	**582**	**273**	**7**	**–**	**–**	**(18)**	**2,112**
Operating expenses	**253**	130	67	50	28	**275**	**55**	**14**	**135**	**16**	**(5)**	**743**
Amortization	**97**	85	34	45	18	**182**	**36**	**10**	**15**	**8**	**–**	**348**
Operating income	**284**	85	68	85	39	**277**	**44**	**51**	**57**	**2**	**(15)**	**700**
Finance charges	**129**	42	28	33	18	**121**	**16**	**8**	**24**	**80**	**(15)**	**363**
Corporate taxes (recoveries)	**37**	(3)	6	19	7	**29**	**2**	**10**	**10**	**(23)**	**–**	**65**
Non-controlling interest	**–**	–	–	1	–	**1**	**9**	**3**	**–**	**–**	**–**	**13**
Net earnings (loss)	**118**	46	34	32	14	**126**	**17**	**30**	**23**	**(55)**	**–**	**259**
Preference share dividends	**–**	–	–	–	–	**–**	**–**	**–**	**–**	**14**	**–**	**14**
Net earnings (loss) applicable to common shares	**118**	46	34	32	14	**126**	**17**	**30**	**23**	**(69)**	**–**	**245**
Goodwill	**903**	227	221	–	63	**511**	**161**	**–**	**–**	**–**	**–**	**1,575**
Identifiable assets	**3,721**	1,574	990	1,001	520	**4,085**	**867**	**285**	**559**	**126**	**(40)**	**9,603**
Total assets	**4,624**	1,801	1,211	1,001	583	**4,596**	**1,028**	**285**	**559**	**126**	**(40)**	**11,178**
Gross capital expenditures	**220**	302	117	67	46	**532**	**110**	**19**	**14**	**9**	**–**	**904**

Year ended December 31, 2007 *($ millions)*												
Revenue	905	270	229	491	263	1,253	307	75	191	22	(35)	2,718
Energy supply costs	559	–	67	327	174	568	169	8	–	–	(17)	1,287
Operating expenses	150	122	69	53	29	273	49	14	123	13	(5)	617
Amortization	58	75	31	34	17	157	28	10	14	6	–	273
Operating income	138	73	62	77	43	255	61	43	54	3	(13)	541
Finance charges	80	36	26	34	17	113	15	10	24	70	(13)	299
Gain on sale of property	(8)	–	–	–	–	–	–	–	–	–	–	(8)
Corporate taxes (recoveries)	16	(11)	5	12	10	16	2	8	6	(12)	–	36
Non-controlling interest	–	–	–	1	–	1	13	1	–	–	–	15
Net earnings (loss)	50	48	31	30	16	125	31	24	24	(55)	–	199
Preference share dividends	–	–	–	–	–	–	–	–	–	6	–	6
Net earnings (loss) applicable to common shares	50	48	31	30	16	125	31	24	24	(61)	–	193
Goodwill	907	227	221	–	63	511	126	–	–	–	–	1,544
Identifiable assets	3,540	1,294	914	986	484	3,678	652	235	535	108	(19)	8,729
Total assets	4,447	1,521	1,135	986	547	4,189	778	235	535	108	(19)	10,273
Gross capital expenditures	120	285	147	72	38	542	106	17	13	5	–	803

(1) The Terasen Gas companies were acquired on May 17, 2007.

(2) Includes Maritime Electric and FortisOntario

(3) Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos. Results for 2008 include two additional months of contribution from Caribbean Utilities due to a change in the utility's fiscal year end.

22. Segmented Information (cont'd)

Inter-segment transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant inter-segment transactions primarily related to the sale of energy from Fortis Generation to Belize Electricity and FortisOntario, electricity sales from Newfoundland Power to Fortis Properties and finance charges on inter-segment borrowings. The significant inter-segment transactions during the years ended December 31 were as follows:

(in millions)	**2008**	2007
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	**$ 17**	$ 15
Sales from Fortis Generation to Other Canadian Electric Utilities	**1**	1
Sales from Newfoundland Power to Fortis Properties	**4**	4
Inter-segment finance charges on borrowings from:		
Corporate to Regulated Electric Utilities – Canadian	**2**	2
Corporate to Regulated Electric Utilities – Caribbean	**5**	1
Corporate to Fortis Properties	**8**	8

23. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	**2008**	2007
Interest paid	**$ 373**	$ 288
Income taxes paid	**33**	53

24. Capital Management

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital in order to allow the utilities to fund the maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent debt, as well as investment-grade credit ratings.

Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates. Fortis generally finances a significant portion of acquisitions with proceeds from common and preference share issuances.

The consolidated capital structure of Fortis is presented in the following table.

	As at December 31, 2008		As at December 31, 2007	
	(in millions)	*(%)*	*(in millions)*	*(%)*
Total debt and capital lease obligations (net of cash)[(1)]	**$ 5,468**	**59.5**	$ 5,476	64.3
Preference shares[(2)]	**667**	**7.3**	442	5.2
Common shareholders' equity	**3,046**	**33.2**	2,601	30.5
Total	**$ 9,181**	**100.0**	$ 8,519	100.0

(1) Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash

(2) Includes preference shares classified as both long-term liabilities and equity

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70 per cent of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. As at December 31, 2008, the Corporation and its subsidiaries, except for Belize Electricity and the Exploits Partnership as described below, were in compliance with their debt covenants.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 rate application, Belize Electricity does not meet certain debt covenant financial ratios related to loans totalling $11 million (BZ$18 million) as at December 31, 2008. The Company has informed the lenders of the defaults and has requested appropriate waivers. Belize Electricity is also in default of certain debt covenants which has resulted in Belize Electricity being prohibited from incurring new indebtedness or declaring dividends.

As a result of legislation passed in 2008 by the Government of Newfoundland and Labrador expropriating most of the Newfoundland assets of Abitibi-Consolidated, the Exploits Partnership is potentially in default on a $61 million term loan. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The term loan, which is non-recourse to Fortis, has been reclassified to current portion of long-term debt on the consolidated balance sheet as at December 31, 2008. See Note 28 for a further discussion of the Exploits Partnership.

The Corporation's credit ratings and consolidated credit facilities are discussed further under "Liquidity Risk" in Note 26.

25. Financial Instruments

The Corporation has designated its non-derivative financial instruments as follows:

	December 31, 2008		December 31, 2007	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and cash equivalents(1)	**$ 66**	**$ 66**	$ 58	$ 58
Loans and receivables				
Trade and other accounts receivable(1)(2)(3)	**674**	**674**	630	630
Other receivables due from customers(1)(3)(4)	**8**	**8**	7	7
Other financial liabilities				
Short-term borrowings(1)(3)	**410**	**410**	475	475
Trade and other accounts payable(1)(3)(5)	**782**	**782**	714	714
Dividends payable(1)(3)	**47**	**47**	43	43
Customer deposits(1)(3)(6)	**6**	**6**	5	5
Long-term debt, including current portion(7)(8)	**5,088**	**4,927**	5,023	5,635
Preference shares, classified as debt(7)(9)	**320**	**329**	320	346

(1) Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.
(2) Included in accounts receivable on the balance sheet
(3) Carrying value approximates amortized cost
(4) Included in deferred charges and other assets on the balance sheet
(5) Included in accounts payable and accrued charges on the balance sheet
(6) Included in deferred credits on the balance sheet
(7) Carrying value is measured at amortized cost using the effective interest rate method.
(8) Carrying value at December 31, 2008 is net of unamortized deferred financing costs of $34 million (December 31, 2007 – $33 million).
(9) Preference shares classified as equity are excluded from the requirements of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*; however, the estimated fair value of the Corporation's $347 million preference shares classified as equity was $268 million as at December 31, 2008 (December 31, 2007 – carrying value $122 million; fair value $107 million).

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the consolidated balance sheets approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments. The fair value of long-term debt is calculated by using quoted market prices, when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

The Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

	2008				2007	
Asset (Liability)	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *(in millions)*	**Estimated Fair Value** *(in millions)*	Carrying Value *(in millions)*	Estimated Fair Value *(in millions)*
Interest rate swaps(1)	**1 to 2**	**2**	**$ –**	**$ –**	$ –	$ –
Foreign exchange forward contract	**< 3**	**1**	**7**	**7**	–	–
Natural gas derivatives:(2)						
Swaps and options	**Up to 3**	**228**	**(84)**	**(84)**	(79)	(79)
Gas purchase contract premiums	**Up to 3**	**74**	**(8)**	**(8)**	5	5

(1) Interest rate swap contracts mature in July 2009 and October 2010. The contracts have the effect of fixing the rate of interest on the non-revolving credit facilities of Fortis Properties at 6.16 per cent and 5.32 per cent, respectively.
(2) The fair values of the natural gas derivatives were recorded in accounts payable as at December 31, 2008 (December 31, 2007 – in accounts payable and accounts receivable).

25. Financial Instruments (cont'd)

The fair value of the Corporation's financial instruments, including derivatives, reflects a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

26. Financial Risk Management

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk — Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk — Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk — Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to the following market risks:

- Foreign exchange risk
- Interest rate risk
- Commodity price risk

Credit Risk

For cash and cash equivalents, trade and other accounts receivable, and other receivables due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits and credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution-service billings being to a relatively small group of retailers and, as at December 31, 2008, its gross credit risk exposure was approximately $87 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $3 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The aging analysis of the Corporation's consolidated trade and other accounts receivable is as follows:

(in millions)	**As at December 31, 2008**
Not past due	**$ 587**
Past due 0–30 days	**70**
Past due 31–60 days	**14**
Past due 61 days and over	**19**
	690
Less: allowance for doubtful accounts	**(16)**
	$ 674

As at December 31, 2008, other receivables due from customers of $8 million and the receivable associated with the foreign exchange forward contract of $7 million will be received over the next six years, with $7 million expected to be received in 2009, $5 million over 2010 and 2011, $2 million over 2012 and 2013 and $1 million in 2014.

Liquidity Risk

The Corporation's financial position could be adversely affected if it, or its operating subsidiaries, fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

Committed credit facilities at Fortis are available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. Over the next five years, average consolidated annual long-term debt maturities and repayments are expected to be approximately $180 million. The combination of available credit facilities and low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing and access to capital markets.

As at December 31, 2008, the Corporation and its subsidiaries had consolidated credit facilities of $2.2 billion, of which $1.5 billion was unused. The credit facilities are syndicated almost entirely with the seven largest Canadian banks with no one bank holding more than 25 per cent of these facilities.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

(in millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2008**	Total as at December 31, 2007
Total credit facilities	$ 715	$ 1,500	$ 13	**$ 2,228**	$ 2,234
Credit facilities utilized:					
Short-term borrowings	–	(410)	–	**(410)**	(475)
Long-term debt *(Note 10)*[(1)]	(32)	(192)	–	**(224)**	(530)
Letters of credit outstanding	(1)	(102)	(1)	**(104)**	(159)
Credit facilities available	$ 682	$ 796	$ 12	**$ 1,490**	$ 1,070

[(1)] As at December 31, 2008, credit-facility borrowings classified as long-term debt included $8 million that was included in current installments of long-term debt and capital lease obligations on the balance sheet.

As at December 31, 2008 and December 31, 2007, certain borrowings under the Corporation's and its subsidiaries' credit facilities have been classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Corporate and Other

Terasen Inc. has a $100 million unsecured committed revolving credit facility, maturing May 2009, that is available for general corporate purposes. Letters of credit of $50 million previously outstanding at Terasen Inc., related to its previously owned petroleum transportation business and secured by a letter of credit from the former parent company, were cancelled during the second quarter of 2008.

Fortis has a $600 million unsecured committed revolving credit facility, maturing May 2012, and a $15 million unsecured demand facility. Both facilities are available for general corporate purposes and the committed facility is also available for interim financing of acquisitions.

Regulated Utilities

TGI has a $500 million unsecured committed revolving credit facility, maturing August 2013. TGVI has a $350 million unsecured committed revolving credit facility, maturing January 2011. The facilities are utilized to finance working capital requirements and capital expenditures, and for general corporate purposes. TGVI also has a $20 million subordinated unsecured committed non-revolving credit facility, maturing in January 2013. This facility can only be utilized for refinancing annual repayments on non-interest bearing government loans.

FortisAlberta has a $200 million unsecured committed revolving credit facility, maturing May 2012, utilized to finance capital expenditures and for general corporate purposes and, with the consent of the lenders, the amount of the facility can be increased to $250 million. FortisAlberta also has a $10 million unsecured demand credit facility.

FortisBC has a $150 million unsecured committed revolving credit facility of which $50 million matures May 2011 and the remaining $100 million matures May 2009. Additionally, the Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC also has a $10 million unsecured demand facility.

Newfoundland Power has $120 million of unsecured credit facilities, comprised of a $100 million committed revolving credit facility, which matures August 2011, and a $20 million uncommitted demand facility.

Maritime Electric had a $50 million unsecured demand revolving credit facility at December 31, 2008. In March 2009, the credit facility was renegotiated and converted into a 364-day revolving committed credit facility.

FortisOntario has secured lines of credit totalling $20 million of which $12 million is authorized solely for letters of credit.

26. Financial Risk Management (cont'd)

Regulated Utilities (cont'd)

Caribbean Utilities has credit facilities of US$33 million ($40 million), comprised of a capital expenditure line of credit of US$18 million ($22 million), including amounts available for letters of credit, a US$7.5 million ($9 million) operating line of credit and a US$7.5 million ($9 million) catastrophe standby loan.

Fortis Turks and Caicos has credit facilities of US$21 million ($25.5 million), comprised of an operating credit facility of US$5 million ($6 million), a capital expenditure line of credit of US$7 million ($8.5 million) and a US$9 million ($11 million) emergency standby loan.

Belize Electricity has a BZ$2 million ($1 million) and BZ$5 million ($3 million) demand overdraft credit facility with Belize Bank Limited and Scotiabank, respectively.

In November 2008, First Caribbean International Bank withdrew its credit facility with Belize Electricity requiring the Company to repay approximately BZ$4 million ($2 million) outstanding under the facility. Scotiabank has also put Belize Electricity on notice that it may not renew its BZ$5 million ($3 million) credit facility with the Company if financial conditions do not show signs of improvement. As at December 31, 2008, the credit facility was undrawn.

Fortis Properties

Fortis Properties has a $13 million secured revolving demand facility utilized for general corporate purposes.

Furthermore, the Corporation and its currently rated subsidiaries target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2008, the Corporation's credit ratings were as follows:

Standard & Poor's	A– (long-term corporate and unsecured debt credit rating)
DBRS	BBB(high) (unsecured debt credit rating)

The credit ratings reflect the diversity of the operations of Fortis, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level and the continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2008.

Financial Liabilities

(in millions)	≤ 1 year	>1–3 years	4–5 years	>5 years	**Total**
Short-term borrowings	$ 410	$ –	$ –	$ –	**$ 410**
Trade and other accounts payable	782	–	–	–	**782**
Natural gas derivatives	70	22	–	–	**92**
Dividends payable	47	–	–	–	**47**
Customer deposits	2	2	1	1	**6**
Long-term debt, including current portion[(1)]	240	319	335	4,228	**5,122**
Interest obligations on long-term debt	304	698	583	3,993	**5,578**
Preference shares, classified as debt	–	–	–	320	**320**
	$ 1,855	$ 1,041	$ 919	$ 8,542	**$ 12,357**

[(1)] Excluding deferred financing costs of $34 million included in the carrying value as per Note 25

Market Risk

Foreign Exchange Risk

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar while the reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00 = US$1.00.

As at December 31, 2008, all of the Corporation's corporately held US$403 million of long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. As at December 31, 2008, the Corporation had approximately US$119 million in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings that are designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income.

A 5 per cent appreciation of the US dollar relative to the Canadian dollar would have increased earnings by $0.6 million for the year ended December 31, 2008 and would have decreased other comprehensive income by $25 million for the year ended December 31, 2008. This sensitivity analysis is limited to the net impact on earnings of the translation of US dollar interest expense and earnings' streams from the Corporation's foreign subsidiaries and the impact on other comprehensive income of the translation of the US dollar borrowings. The sensitivity analysis excludes the risk arising from the translation of self-sustaining foreign net investments to the Canadian dollar because such investments are not financial instruments. However, a 5 per cent appreciation of the US dollar relative to the Canadian dollar associated with the translation of the Corporation's net investment in self-sustaining foreign subsidiaries would have increased other comprehensive income by $32 million for the year ended December 31, 2008.

TGVI's US dollar payments under a contract for the construction of an LNG storage facility exposes TGVI to fluctuations in the US dollar-to-Canadian dollar exchange rate. TGVI has entered into a foreign exchange forward contract to hedge this exposure. At December 31, 2008, a 5 per cent appeciation of the US dollar relative to the Canadian dollar, as it affects the measurement of the fair value of the foreign exchange forward contract, in the absence of rate regulation and with all other variables remaining constant, would have increased earnings by $3 million for the year ended December 31, 2008. Furthermore, TGVI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than other comprehensive income.

Interest Rate Risk

The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk and, during 2008, the Terasen Gas companies and Fortis Properties were parties to interest rate swap agreements that effectively fixed the interest rates on their variable-rate borrowings. During the fourth quarter of 2008, the Terasen Gas companies' interest rate swaps matured. A 100 basis point increase in interest rates associated with variable-rate debt, with all other variables remaining constant, would have decreased earnings by $5 million for the year ended December 31, 2008. Furthermore, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate debt for recovery from, or refund to, customers in future rates.

As at December 31, 2008, a 100 basis point increase in interest rates as it affects the measurement of fair value of the interest rate swap agreements would have increased other comprehensive income by $0.1 million during the year ended December 31, 2008.

In addition, certain of the committed credit facilities have fees that are linked to the Corporation's or its subsidiaries' credit ratings. A downward change in the credit ratings of the Corporation and its currently rated subsidiaries by one level, with all other variables remaining constant, would have decreased earnings by $0.9 million for the year ended December 31, 2008.

Commodity Price Risk

The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk is minimized by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The natural gas derivatives are recorded on the balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

Had the price of natural gas, with all other variables remaining constant, increased by $1 per gigajoule, the fair value of the natural gas derivatives would have increased and, in the absence of rate regulation, other comprehensive income would have increased by $54 million for the year ended December 31, 2008. However, the Terasen Gas companies defer any changes in fair value of the natural gas derivatives, subject to regulatory approval, for future recovery from, or refund to, customers in future rates. Therefore, instead of increasing other comprehensive income, current regulatory assets would have decreased by $54 million.

27. Commitments

(in millions)	Total	< 1 year	1–3 years	4–5 years	> 5 years
Gas purchase contract obligations(1)	**$ 466**	$ 416	$ 50	$ –	$ –
Power purchase obligations					
FortisBC(2)	**2,829**	40	76	78	2,635
FortisOntario(3)	**561**	45	94	99	323
Maritime Electric(4)	**72**	52	2	2	16
Belize Electricity(5)	**16**	4	4	2	6
Capital cost(6)	**400**	16	41	41	302
Joint-use asset and shared service agreements(7)	**62**	4	7	6	45
Office lease – FortisBC(8)	**19**	1	4	2	12
Operating lease obligations(9)	**166**	18	33	29	86
Other	**25**	4	10	6	5
Total	**$ 4,616**	$ 600	$ 321	$ 265	$ 3,430

(1) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2008.

(2) Power purchase obligations of FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the power purchase agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric generating plant located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The power purchase agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

(3) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The first contract provides approximately 237 gigawatt hours ("GWh") of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(4) Maritime Electric has two take-or-pay contracts for the purchase of either capacity or energy. The contracts total approximately $72 million through November 30, 2032. The take-or-pay contract with New Brunswick Power ("NB Power") includes, among other things, replacement energy and capacity for the NB Power Point Lepreau Nuclear Generating Station during its refurbishment outage. The other take-or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new International Power Line into the United States.

(5) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity and a two-year power purchase agreement, expiring in December 2010, between Belize Electricity and Comisión Federal de Electricidad of Mexico for the supply of 50 MW of firm capacity and associated energy. Belize Electricity has also signed two 15-year power purchase agreements with Belize Cogeneration Energy Limited ("Belcogen") and Belize Aquaculture Limited that provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively. As the generating plants are not yet connected to the electricity system, the obligations related to the power purchase agreements with Belcogen and Belize Aquaculture Limited have not been included in the Corporation's commitments table above.

(6) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Nuclear Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

[7] FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2013 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

[8] Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term.

[9] Operating lease obligations include certain office, warehouse, natural gas transmission and distribution asset, and vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro Inc.

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by customer requests and by large capital projects specifically approved by their respective regulatory authorities. The consolidated capital program of the Corporation, including non-regulated segments, is forecasted to be approximately $1 billion for 2009. This commitment has not been included in the commitments table above.

In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and are subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates.

The repayment criteria were met in 2008 and TGVI is expected to make an $8 million repayment on the loans in 2009 (2008 – $6 million). As at December 31, 2008, the outstanding balance of the repayable government loans was $61 million with $8 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the commitments table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGVI's RDDA and the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-fired generating plant. The contract is for three years terminating in April 2010. The remaining approximate quantities, in millions of imperial gallons, required to be purchased annually for each of the 12-month periods ended December 31 are: 2009 – 27 and 2010 – 9.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Based on the last completion of actuarial valuations, the Corporation's required consolidated defined benefit pension plan funding contributions are expected to be approximately $17 million for 2009 and $12 million for 2010. The level of the defined benefit pension plan funding contributions will be affected by the outcome, in 2009, of December 31, 2008 actuarial valuations for Newfoundland Power, the Corporation and one of the defined benefit pension plans at Terasen. The next scheduled actuarial valuations for the remaining larger defined benefit pension plans are not until December 2009 and December 2010.

28. Contingent Liabilities

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to $7 million, including interest, which has been paid in full to avoid accruing further interest and it is recorded as a long-term regulatory deferral asset. The matter is currently under appeal to the Supreme Court of British Columbia (Note 4 *(ix)*).

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. Terasen has begun the appeal process associated with the assessments.

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGVI seeking damages for alleged past overpayments and a future reduction in tolls. The Statement of Claim does not quantify damages and, as such, the Company cannot determine the amount of the claim at this time. It is the Company's view that the claim is without merit. No amount, therefore, has been accrued in the consolidated financial statements.

FortisBC

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by a private landowner in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of the NB Power Point Lepreau Nuclear Generating Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation which confirmed the April 2006 reassessments. The Company will file an Appeal to the Tax Court of Canada.

Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $13 million in taxes and accrued interest. As at December 31, 2008, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

FortisUS Energy

During 2008, a statutory discontinuance and final release of FortisUS Energy was issued in relation to legal proceedings initiated by the Village of Philadelphia (the "Village"), New York. The Village had claimed that FortisUS Energy should honour a series of current and future payments set out in an agreement between the Village and a former owner of the hydroelectric site, located in the municipality of the Village, now owned by FortisUS Energy, totalling approximately $9 million (US$7 million). There was no impact on the consolidated financial statements as a result of the settlement of these legal proceedings.

Exploits Partnership

On December 16, 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of the Newfoundland assets of Abitibi-Consolidated. Prior to that date, Abitibi-Consolidated announced the closure of its Grand Falls-Windsor, Newfoundland newsprint mill, effective March 31, 2009. The hydroelectric generating facility assets of the Exploits Partnership were included as part of the expropriation legislation. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The financial statements of the Exploits Partnership are consolidated in the financial statements of Fortis. The Exploits Partnership has a $61 million term loan, which is non-recourse to Fortis, with several lenders which is secured by the assets of the Exploits Partnership.

Discussions are ongoing with the Exploits Partnership's lenders with respect to the above matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated. Pending resolution of these matters, the deferred financing costs of $2 million and utility capital assets of $61 million related to the Exploits Partnership have been reclassified to deferred charges and other assets and the $61 million term loan has been classified as current on the consolidated balance sheet of Fortis as at December 31, 2008.

29. Subsequent Events

In February 2009, FortisAlberta issued $100 million of 30-year 7.06% unsecured debentures under the short-form base shelf prospectus that was filed in December 2008. The net proceeds were used to repay committed credit-facility borrowings incurred in support of the Company's capital expenditure program and for general corporate purposes.

In February 2009, TGI issued $100 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay $60 million of unsecured debentures that mature in June 2009.

30. Comparative Figures

Certain comparative figures have been reclassified to comply with the current year's classifications.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	2008	2007	2006[1]	2005[1]
Revenue, including equity income	**3,903**	2,718	1,472	1,441
Energy supply costs and operating expenses	**2,855**	1,904	939	926
Amortization	**348**	273	178	158
Finance charges	**363**	299	168	154
Corporate taxes	**65**	36	32	70
Results of discontinued operations, gains on sales and other unusual items	**–**	8	2	10
Non-controlling interest	**13**	15	8	6
Preference share dividends	**14**	6	2	–
Net earnings applicable to common shares	**245**	193	147	137
Balance Sheets *(in $ millions)*				
Current assets	**1,150**	1,038	405	299
Goodwill	**1,575**	1,544	661	512
Other long-term assets	**545**	424	331	471
Utility capital assets and income producing properties	**7,908**	7,267	4,044	3,315
Total assets	**11,178**	10,273	5,441	4,597
Current liabilities	**1,697**	1,804	558	412
Deposits due beyond one year	**–**	–	–	–
Deferred credits, regulatory liabilities and future income taxes	**739**	688	477	477
Long-term debt and capital lease obligations (excluding current portion)	**4,884**	4,623	2,558	2,136
Non-controlling interest	**145**	115	130	39
Preference share (classified as debt)	**320**	320	320	320
Shareholders' equity	**3,393**	2,723	1,398	1,213
Cash Flows *(in $ millions)*				
Operating activities	**663**	373	263	304
Investing activities	**854**	2,033	634	467
Financing activities	**387**	1,826	456	224
Dividends, excluding dividends on preference shares classified as debt	**191**	146	77	64
Financial Statistics				
Return on average common shareholders' equity *(%)*	**8.70**	10.00	11.87	12.40
Capitalization Ratios *(%)* (year end)				
Total debt and capital lease obligations (net of cash)	**59.5**	64.3	61.1	58.7
Preference shares (classified as debt and equity)	**7.3**	5.2	10.0	8.6
Common shareholders' equity	**33.2**	30.5	28.9	32.7
Interest Coverage *(x)*				
Debt	**1.9**	1.9	2.2	2.5
All fixed charges	**1.8**	1.7	2.0	2.1
Total gross capital expenditures *(in $ millions)*	**904**	803	500	446
Common share data				
Book value per share (year end) *($)*	**17.97**	16.69	12.19	11.74
Average common shares outstanding *(in millions)*	**157.4**	137.6	103.6	101.8
Basic earnings per common share *($)*	**1.56**	1.40	1.42	1.35
Dividends declared per common share *($)*	**1.010**	0.880	0.700	0.605
Dividends paid per common share *($)*	**1.000**	0.820	0.670	0.588
Dividend payout ratio *(%)*	**64.1**	58.6	47.2	43.7
Price earnings ratio *(x)*	**15.8**	20.7	21.0	18.0
Share trading summary				
High price *($)* (TSX)	**29.94**	30.00	30.00	25.64
Low price *($)* (TSX)	**20.70**	24.50	20.36	17.00
Closing price *($)* (TSX)	**24.59**	28.99	29.77	24.27
Volume *(in thousands)*	**132,108**	100,920	60,094	37,706

[1] As at December 31, 2006, the regulatory provision for future asset removal and site restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated. The effect of this change in presentation at December 31, 2006 was a $306.5 million (December 31, 2005 – $280.9 million) increase in long-term regulatory liabilities and a $306.5 million (December 31, 2005 – $280.9 million) increase in net utility capital assets.

2004	2003	2002	2001	2000	1999	1998
1,146	843	715	628	580	505	473
766	579	477	418	418	356	340
114	62	65	62	52	45	42
122	86	74	65	56	46	44
47	38	32	29	17	28	23
–	–	–	4	3	–	4
6	4	4	4	3	1	1
–	–	–	–	–	–	–
91	74	63	54	37	29	27
293	191	180	135	166	93	94
514	65	60	33	36	39	42
418	345	241	172	163	122	121
2,713	1,563	1,459	1,246	1,056	930	750
3,938	2,164	1,940	1,586	1,421	1,184	1,007
538	296	334	272	225	230	148
–	–	–	–	–	16	16
138	62	39	32	24	27	22
1,905	1,031	941	746	678	488	424
37	37	40	36	32	29	8
320	123	–	50	50	50	50
1,000	615	586	450	412	344	339
272	157	134	94	97	85	69
1,026	308	349	240	241	122	66
777	232	261	171	178	67	16
51	38	35	30	28	24	24
11.28	12.30	12.23	12.44	9.73	8.55	8.24
61.4	60.0	65.2	63.9	60.4	59.6	53.4
9.4	6.7	–	3.6	4.3	5.1	6.0
29.2	33.3	34.8	32.5	35.3	35.3	40.6
2.3	2.2	2.3	2.3	2.1	2.3	2.2
2.0	2.1	2.2	2.2	1.9	2.1	2.0
279	208	229	149	158	86	65
10.45	8.82	8.50	7.50	6.97	6.55	6.52
84.7	69.3	65.1	59.5	54.1	52.2	51.5
1.07	1.06	0.97	0.90	0.68	0.56	0.53
0.548	0.525	0.498	0.470	0.460	0.455	0.450
0.540	0.520	0.485	0.468	0.460	0.453	0.450
50.3	48.9	49.9	51.9	67.6	80.8	84.9
16.2	13.9	13.5	13.0	13.2	14.0	18.0
17.75	15.24	13.28	11.89	9.19	9.93	12.03
14.23	11.63	10.76	8.56	6.88	7.29	8.75
17.38	14.73	13.13	11.74	9.00	7.85	9.56
29,254	31,180	21,676	21,460	26,760	9,024	12,356

Board of Directors (l-r): David G. Norris, Peter E. Case, Harry McWatters, John S. McCallum, Geoffrey F. Hyland, Roy P. Rideout, Linda L. Inkpen, Michael A. Pavey, H. Stanley Marshall, Frank J. Crothers

Board of Directors

Geoffrey F. Hyland ∗★✷ *Chair, Fortis Inc., Caledon, ON*
Mr. Hyland, 64, joined the Fortis Inc. Board in May 2001 and was appointed Chair of the Board in May 2008. He retired as President and CEO of Shawcor Ltd. in June 2005 after 37 years of service. Mr. Hyland is a Director of FortisOntario Inc. He continues to serve on the Board of ShawCor Ltd. and is a Director of Enerflex Systems Income Fund, SCITI Total Return Trust and Exco Technologies Limited.

Peter E. Case ∗ *Corporate Director, Freelton, ON*
Mr. Case, 54, joined the Fortis Inc. Board in May 2005. After 17 years as a utility and pipeline analyst, he retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. Prior to that position, he was Managing Director at BMO Nesbitt Burns. Mr. Case has been a Director of FortisOntario Inc. since March 2003.

Frank J. Crothers *Chairman & CEO, Island Corporate Holdings, Nassau, Bahamas*
Mr. Crothers, 64, joined the Fortis Inc. Board in May 2007. Over the past 35 years, Mr. Crothers has served on many public and private sector boards. He served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the former President of P.P.C. Limited, which was acquired by Fortis Inc. in August 2006. He serves as Vice Chair of the Board of Caribbean Utilities Company, Limited and serves on the Board of Belize Electricity. Mr. Crothers also serves as a Director of Franklin Templeton Resources, Talon Metals Corp, Fidelity Merchant Bank & Trust (Cayman) Limited and Victory Nickel Inc.

Linda L. Inkpen ★ *Corporate Director, St. John's, NL*
Dr. Inkpen, 61, joined the Fortis Inc. Board in 1994. She retired from her medical practice in December 2008 after 35 years of service and is past Chair of the Medical Advisory Committee for the St. John's Hospitals for Eastern Health. Dr. Inkpen is a past President of the College of the North Atlantic. She also served on the Royal Commission on Employment and Unemployment. Dr. Inkpen is past Chair of the Boards of Fortis Properties Corporation and Newfoundland Power Inc. She will be retiring from the Fortis Inc. Board at the Annual Meeting on May 5, 2009.

H. Stanley Marshall *President and CEO, Fortis Inc., St. John's, NL*
Mr. Marshall, 58, has served on the Fortis Inc. Board since 1995. He joined Newfoundland Power Inc. in 1979 and was appointed President and CEO of Fortis Inc. in 1996. Mr. Marshall serves on the Boards of all Fortis utilities in western Canada and the Caribbean and the Board of Fortis Properties Corporation. He is also a Director of Toromont Industries Ltd.

John S. McCallum ∗★ *Professor of Finance, University of Manitoba, Winnipeg, MB*
Mr. McCallum, 65, joined the Fortis Inc. Board in July 2001 and is Chair of the Governance and Nominating Committee of the Board. He was Chairman of Manitoba Hydro from 1991 to 2000 and Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum is a Director of FortisBC Inc. and FortisAlberta Inc. He also serves as a Director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.

Harry McWatters ★ *Wine Consultant, Summerland, BC*
Mr. McWatters, 63, joined the Fortis Inc. Board in May 2007. He is the founder and past President of Sumac Ridge Estate Wine Group. Mr. McWatters is President of Harry McWatters Inc., Vintage Consulting Group Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd. He was appointed Chair of the Board of FortisBC Inc. in 2006. Mr. McWatters has been a Director of FortisBC Inc. since 2005 and a Director of Terasen Inc. since November 2007.

David G. Norris ∗✷ *Corporate Director, St. John's, NL*
Mr. Norris, 61, joined the Fortis Inc. Board in May 2005 and was appointed Chair of the Audit Committee of the Board in May 2006. He has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris was appointed Chair of the Board of Newfoundland Power Inc. in 2006. He has been a Director of Newfoundland Power Inc. since 2003 and a Director of Fortis Properties Corporation since 2006.

Michael A. Pavey ✷ *Corporate Director, Moncton, NB*
Mr. Pavey, 61, joined the Fortis Inc. Board in May 2004. He retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in 2006. Prior to joining Major Drilling in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey was previously a Director of Maritime Electric Company, Limited.

Roy P. Rideout ★✷ *Corporate Director, Halifax, NS*
Mr. Rideout, 61, joined the Fortis Inc. Board in March 2001 and is Chair of the Human Resources Committee of the Board. He retired as Chairman and CEO of Clarke Inc. in October 2002. Prior to 1998, Mr. Rideout served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. He also serves as a Director of the Halifax International Airport Authority and NAV CANADA.

∗ Audit Committee
★ Governance and Nominating Committee
✷ Human Resources Committee

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Fortis Inc. Officers (l-r): Barry Perry, VP, Finance and CFO; Donna Hynes, Assistant Secretary and Manager, Investor and Public Relations; Stan Marshall, President and CEO; Ronald McCabe, VP, General Counsel and Corporate Secretary

Investor Information

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issue, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.computershare.com/fortisinc

Direct Deposit of Dividends

Shareholders may obtain automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends." Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 8, 2009	August 7, 2009
November 6, 2009	February 5, 2010

Dividend Payment Dates

June 1, 2009	September 1, 2009
December 1, 2009	March 1, 2010

Earnings Release Dates

April 30, 2009	August 5, 2009
November 5, 2009	February 4, 2010

* *The declaration and payment of dividends are subject to the Board of Directors' approval.*

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis Inc. offers a Dividend Reinvestment Plan ("DRIP")(1) and a Consumer Share Purchase Plan ("CSPP")(2) to Common Shareholders as a convenient method of increasing their investments in Fortis Inc. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; and First Preference Shares, Series G of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F and FTS.PR.G, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$ 1.531
February 22, 1994	$ 7.156

Analyst and Investor Inquiries

Manager, Investor
and Public Relations
T: 709.737.2800
F: 709.737.5307
E: investorrelations@fortisinc.com

Annual Meeting

Tuesday, May 5, 2009
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Design and Production:
Colour, St. John's, NL
www.colour-nl.ca

Moveable Inc., Toronto, ON

Printer:
The Lowe-Martin Group,
Ottawa, ON

FORTIS INC.

The Fortis Building
Suite 1201, 139 Water Street
PO Box 8837
St. John's, NL Canada A1B 3T2

T: 709.737.2800
F: 709.737.5307

WWW.FORTISINC.COM TSX:FTS

Delivering long-term value for customers and shareholders.

Attachment 84.4

CONSOLIDATED FINANCIAL STATEMENTS OF

TERASEN GAS INC.

YEARS ENDED DECEMBER 31, 2004 AND 2003

Management's Responsibility

The consolidated financial statements have been prepared by management, which is responsible for the integrity and objectivity of this information. These financial statements have been prepared in conformity with Canadian generally accepted accounting principles and, where appropriate, include some amounts that are based on management's best estimates and judgments. The financial information presented elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established systems of internal control which are designed to provide reasonable assurance that assets are safeguarded from loss and that reliable financial records are maintained. These systems are monitored by internal auditors.

KPMG LLP, the independent auditors appointed by the shareholders, have audited the consolidated financial statements of the Company in accordance with Canadian generally accepted auditing standards and have expressed their opinion upon completion of such audits in the following report. In order to provide their opinion on these consolidated financial statements, the shareholders' auditors review the system of internal controls and conduct their work to the extent they consider appropriate.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the consolidated financial statements for issuance to the shareholders.

Signed: *"R.L. (Randy) Jespersen"*

President

Signed: *"Scott A. Thomson"*

Vice President, Finance and
Regulatory Affairs

Vancouver, Canada
February 2, 2005

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated statements of financial position of Terasen Gas Inc. as at December 31, 2004 and 2003 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Signed: *"KPMG LLP"*

Chartered Accountants

Vancouver, Canada
February 2, 2005

CONSOLIDATED STATEMENTS OF EARNINGS

In millions of dollars *Years ended December 31*	**2004**	2003
Revenues		
Natural gas distribution	**$ 1,305.2**	$ 1,305.6
Expenses		
Cost of natural gas	**807.0**	805.2
Operation and maintenance	**164.4**	160.9
Depreciation and amortization	**81.6**	76.7
Property and other taxes	**39.6**	41.4
	1,092.6	1,084.2
Operating income	**212.6**	221.4
Financing costs (note 10)	**106.4**	111.9
Earnings before income taxes	**106.2**	109.5
Current income taxes (note 11)	**35.4**	39.1
Net earnings	**$ 70.8**	$ 70.4

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

In millions of dollars *Years ended December 31*	**2004**	2003
Retained earnings, beginning of year	**$ 27.8**	$ 37.4
Net earnings	**70.8**	70.4
	98.6	107.8
Dividends on common shares	**60.0**	80.0
Retained earnings, end of year	**$ 38.6**	$ 27.8

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

In millions of dollars *As at December 31*	**2004**	2003
Assets		
Current assets		
Cash and short-term investments	**$ 1.7**	$ -
Accounts receivable	**252.9**	318.0
Inventories of gas in storage and supplies	**151.5**	113.6
Prepaid expenses	**5.7**	5.8
Current portion of rate stabilization accounts (note 4)	**13.8**	8.8
	425.6	446.2
Property, plant and equipment (note 3)	**2,260.0**	2,285.8
Rate stabilization accounts (note 4)	**27.9**	32.2
Other assets		
Deferred charges	**25.5**	23.9
Long-term receivables and investments	**8.2**	5.1
	$ 2,747.2	$ 2,793.2
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**$ -**	$ 4.3
Short-term notes	**107.0**	352.9
Accounts payable and accrued liabilities	**254.9**	275.1
Income and other taxes payable	**18.9**	44.5
Current portion of rate stabilization account (note 4)	**27.6**	2.5
Current portion of long-term debt (note 5)	**397.2**	2.2
	805.6	681.5
Long-term debt (note 5)	**1,051.4**	1,297.3
Other long-term liabilities and deferred credits (note 6)	**80.2**	48.9
Future income taxes	**0.5**	0.5
	1,937.7	2,028.2
Shareholders' equity		
Share capital (note 7)	**594.0**	594.0
Contributed surplus (note 7)	**176.9**	143.2
Retained earnings	**38.6**	27.8
	809.5	765.0
	$ 2,747.2	$ 2,793.2

Approved by the Board:

Signed: *"Mark L. Cullen"* (Chairman) Signed: *"John M. Reid"* (Vice Chairman)

CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions of dollars	**2004**	2003
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$ 70.8**	$ 70.4
Adjustments for non-cash items		
Depreciation and amortization	**81.6**	76.7
Other	**(0.9)**	(2.2)
	151.5	144.9
Decrease in rate stabilization accounts	**24.4**	38.2
Changes in non-cash working capital	**15.5**	(37.5)
	191.4	145.6
Investing activities		
Property, plant and equipment	**(93.9)**	(116.2)
Proceeds on sale of natural gas distribution assets (note 6)	**64.6**	-
Proceeds on sale of property, plant and equipment (note 13(a))	**3.1**	-
Other assets	**(2.4)**	(3.7)
	(28.6)	(119.9)
Financing activities		
Increase (decrease) in short-term notes	**(245.9)**	2.9
Increase in long-term debt	**152.1**	152.4
Reduction of long-term debt	**(3.0)**	(103.2)
Dividends on common shares	**(60.0)**	(80.0)
	(156.8)	(27.9)
Increase (decrease) in cash	**6.0**	(2.2)
Bank indebtedness at beginning of year	**(4.3)**	(2.1)
Cash (bank indebtedness) at end of year	**$ 1.7**	$ (4.3)
Supplemental cash flow information		
Interest paid in the year	**$ 103.7**	$ 113.2
Income taxes paid in the year	**31.7**	25.2

Cash is defined as cash or bank indebtedness.

1. SIGNIFICANT ACCOUNTING POLICIES

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses in the financial statements, as well as the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

In the opinion of Management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and reflect the following summary of significant accounting policies.

(a) BASIS OF PRESENTATION

On April 25, 2003, the Company changed its name from BC Gas Utility Ltd. to Terasen Gas Inc. The consolidated financial statements include the accounts of the Company and its subsidiaries, including Terasen Gas (Squamish) Inc. ("Squamish").

Certain comparative figures have been reclassified to conform with the current year's presentation.

(b) REGULATION

The Company and Squamish are primarily engaged in the transmission and retail distribution of natural gas for residential, commercial and large industrial customers in British Columbia and are subject to the regulation of the British Columbia Utilities Commission ("the BCUC").

The BCUC exercises statutory authority over such matters as rates of return, construction and operation of facilities, accounting practices, rates, and contractual agreements with customers.

In order to recognize the economic effects of regulation, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles.

(c) INVENTORIES

Inventories of gas in storage are valued at weighted-average cost. Supplies and other inventories are valued at the lower of cost and net realizable value.

(d) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures for system expansions, betterments and replacements, an allocation of overhead costs and an allowance for funds used during construction. When allowed by the BCUC, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

Depreciation of regulated assets is recorded on a straight-line basis over their useful lives. Depreciation rates for regulated assets are approved by the respective regulator.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The cost of regulated depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation as is any gain or loss incurred on disposal.

(e) IMPAIRMENT OF LONG-LIVED ASSETS

On January 1, 2004, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") standard for recognizing, measuring and disclosing impairment of long-lived assets held for use. A long-lived asset is tested for recoverability when events or circumstances indicate that its carrying amount may not be recoverable. The new standard has had no impact on the Company's financial results.

(f) ASSET RETIREMENT OBLIGATIONS

On January 1, 2004, the Company adopted the new CICA standard for the recognition, measurement and disclosure of liabilities for asset retirement obligations and the associated asset retirement costs. Under the new standard the fair value of a liability for an asset retirement obligation must be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset, which is then expensed over the asset's estimated useful life. The liability is accreted over the useful life of the asset through charges to expenses.

As the fair value of future removal and site restoration costs are not currently determinable, the adoption of the policy does not result in the recording of an asset retirement liability and therefore the consolidated financial statements have not been impacted by the new standard. In addition, for regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

(g) RATE STABILIZATION ACCOUNTS

The Company is authorized by the BCUC to maintain rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility. The Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual versus forecast use for residential and commercial customers.

In 2004 the Gas Cost Reconciliation Account ("GCRA"), which accumulates differences between actual natural gas costs and forecast natural gas costs as recovered in base rates, was replaced by the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA"). The two new accounts were approved by the BCUC to segregate costs that are allocable to all sales customers (MCRA) and all residential customers and certain commercial and industrial customers for whom Terasen Gas acquires gas supply (CCRA).

All rate stabilization account balances are amortized and recovered through rates as approved by the BCUC.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(h) DEFERRED CHARGES

The Company defers certain charges which the regulatory authorities or contractual arrangements require or permit to be recovered through future rates. Deferred charges are amortized over various periods as approved by the BCUC and depending on the nature of the charges.

Deferred charges include long-term debt issue costs which are amortized over the term of the related debt.

Deferred charges not subject to regulation relate to projects which may benefit future periods and will be capitalized on completion, expensed on project abandonment, or are being amortized on a straight-line basis over their useful lives.

(i) DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices.

A derivative must be designated and effective to be accounted for as a hedge. The Company designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Company also assesses, both at inception and on an ongoing basis, whether the derivative instruments that are used in each hedging transaction are effective in offsetting changes in fair values or cash flows of the hedged items.

As approved by the regulator, derivatives are used to manage natural gas price risk in the natural gas distribution operations. The majority of the natural gas supply contracts have floating, rather than fixed prices. The Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in deferral accounts (CCRA and MCRA), and subject to regulatory approval, are passed through in future rates to customers.

The Company's short-term borrowings and variable rate long-term debt are exposed to interest rate risk.

Foreign currency risk in natural gas distribution operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through regulatory deferral accounts. Certain foreign currency risks in the natural gas distribution operations are managed through the use of foreign currency derivatives on behalf of customers.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(j) REVENUE RECOGNITION

The Company recognizes revenues when products have been delivered or services have been performed.

Revenues from natural gas sales are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year and adjusted for the Revenue Stabilization Adjustment Mechanism and other BCUC approved orders.

(k) POST-EMPLOYMENT BENEFIT PLANS

The Company sponsors a number of employee benefits plans. These plans include both defined benefit and defined contribution pension plans, and various other post-retirement benefit plans.

The cost of pensions and other post-retirement benefits earned by employees is actuarially determined as the employee provides service, except when the BCUC requires costs to be expensed as paid. The Company uses the projected benefit method based on years of service and estimates of expected returns on plan assets, salary escalation, retirement age of employees, mortality and expected future health-care costs. The discount rate used to value liabilities is based on AA Corporate bond yields. The Company accrues the cost of defined benefit pensions and post-employment benefits as the employee provides services, except when the BCUC requires costs to be expensed as paid.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets as of December 31, 2004 is calculated as the average of the market value of invested assets at December 31, 2004 and two actuarially determined extrapolated market values of invested assets at December 31, 2004. The two extrapolated market values are calculated by using the market value of invested assets at December 31, 2002 rolled forward to December 31, 2004 using 2003 and 2004 net contributions and assumed investment returns, and the market value of invested assets at December 31, 2003 rolled forward to December 31, 2004 using 2004 net contributions and assumed investment returns. These three amounts are then averaged to determine the market-related value of plan assets used in calculating net benefit expense.

Adjustments, in excess of 10% of the greater of the accrued benefit obligation and plan asset value, that result from plan amendments, changes in assumptions and experience gains and losses are amortized over the expected average remaining service life of the employee group covered by the plan. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

Defined contribution plan costs are expensed by the Company as contributions are payable.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(l) INCOME TAXES

The Company and Squamish account for and recover income tax expense in rates as prescribed by the BCUC for ratemaking purposes. This includes accounting for income taxes by the taxes payable method and accounting for certain deferral and rate stabilization accounts on a net of realized tax basis, as approved by the BCUC. Therefore, future income taxes related to temporary differences are not recorded. The taxes payable method is followed as there is reasonable expectation that all future income taxes will be recovered in rates when they become payable.

2. RESTRUCTURING

During the year ended December 31, 2003, the Company's parent undertook a management and administrative restructuring and integration of its natural gas distribution operations. The initiative was undertaken to generate efficiencies and harmonize processes and systems between the Company and Terasen Gas (Vancouver Island) Inc., a company related by common ownership. As a result of the restructuring, the Company recorded a charge of $3.0 million in 2003 and $0.4 million in 2004, net of previously recorded accruals, tax and the deferral of an amount for future recovery from customers through rates. The pre-tax charges have been included in operations and maintenance expense.

3. PROPERTY, PLANT AND EQUIPMENT

2004	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas distribution systems	**2.40%**	**$ 2,556.0**	**$ 505.8**	**$ 2,050.2**
Plant, buildings and equipment	**9.30%**	**223.1**	**94.5**	**128.6**
Land and land rights	**0.60%**	**82.5**	**1.3**	**81.2**
		$ 2,861.6	**$ 601.6**	**$ 2,260.0**

2003	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas distribution systems	2.40%	$ 2,546.4	$ 470.6	$ 2,075.8
Plant, buildings and equipment	8.40%	240.2	102.4	137.8
Land and land rights	0.60%	73.1	0.9	72.2
		$ 2,859.7	$ 573.9	$ 2,285.8

4. RATE STABILIZATION ACCOUNTS

	2004	2003
Current Assets		
RSAM	$ 11.1	$ 8.8
CCRA	2.7	-
	13.8	8.8
Long-Term Assets		
RSAM	27.9	32.2
	27.9	32.2
Current Liabilities		
MCRA	(27.6)	-
GCRA	-	(2.5)
	(27.6)	(2.5)
Net rate stabilization accounts	$ 14.1	$ 38.5

The current portion of the rate stabilization accounts represents the amounts expected to be recovered in rates over the next twelve months. Actual recoveries will vary depending on actual natural gas consumption and recovery amounts approved by the BCUC.

The RSAM account is anticipated to be recovered in rates over three years. Recovery of the RSAM balance is dependent upon annually approved rates and actual gas consumption volumes. The MCRA and CCRA accounts are anticipated to be fully recovered or paid within the next fiscal year.

5. LONG-TERM DEBT

	2004	2003
(a) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2015	$ 74.9	$ 74.9
10.30% Series B, due September 30, 2016	200.0	200.0
(b) Debentures and Medium Term Note Debentures:		
9.75% Series D, due December 17, 2006	20.0	20.0
10.75% Series E, due June 8, 2009	59.9	59.9
6.20% Series 9, due June 2, 2008	188.0	188.0
6.95% Series 11, due September 21, 2029	150.0	150.0
6.50% Series 12, due July 20, 2005	200.0	200.0
6.50% Series 13, due October 16, 2007	100.0	100.0
6.15% Series 16, due July 31, 2006	100.0	100.0
Floating Rate Series 17, interest rate of 2.93% (2003 – 3.02%) due September 26, 2005	150.0	150.0
6.50% Series 18, due May 1, 2034	150.0	-
Various series, weighted-average interest rate of 9.63% (2003 – 9.63%) due in 2005	45.0	45.0
Obligations under capital leases, at 6.23% (2003 – 6.20%)	10.8	11.7
Total long-term debt	1,448.6	1,299.5
Less: current portion of long-term debt	397.2	2.2
	$ 1,051.4	$ 1,297.3

5. LONG-TERM DEBT (CONTINUED)

(a) PURCHASE MONEY MORTGAGES:

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Company's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

(b) DEBENTURES AND MEDIUM TERM NOTE DEBENTURES:

The Company's debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

The Company's Series B Purchase Money Mortgages, Series E Debentures, and Series 11, Series 13, Series 16 and Series 18 Medium Term Note Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Required principal repayments over the next five years are as follows:

2005	$ 397.2
2006	122.2
2007	102.2
2008	190.2
2009	62.1

6. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS

	2004	2003
Pension and other post-employment benefit liabilities	**$ 19.9**	$ 18.7
Deferred gains on sale of natural gas distribution assets	**60.3**	30.2
	$ 80.2	$ 48.9

The deferred gains on sale of natural gas distribution assets occurred upon the sale of pipeline assets to certain municipalities in 2001, 2002 and 2004. The pre-tax gains of $66.5 million on combined cash proceeds of $135.9 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 14.

7. SHARE CAPITAL

The Company is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

	2004	2003
Common shares, 59,591,732 shares issued	**$ 594.0**	$ 594.0

CONTRIBUTED SURPLUS

Income tax benefits in the amount of $33.7 million (2003 - $17.0 million) relating to transactions with entities under common control were recorded as a credit to contributed surplus in 2004.

8. EMPLOYEE BENEFIT PLANS

The Company is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. The Company also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan:

DEFINED BENEFIT PLANS

Retirement benefits under the defined benefit plans are based on employees' years of credited service and remuneration. Company contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were at December 31, 2002 and December 31, 2001 and the date of the next required valuations are December 31, 2005 and December 31, 2004. The December 31, 2004 valuation will not be completed until the second quarter of 2005. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 9.5 years (2003 - 9.5 years).

DEFINED CONTRIBUTION PLAN

Effective in 2000 all new non-union employees become members of defined contribution pension plans. Company contributions to the plan are based upon employee age and pensionable earnings.

SUPPLEMENTAL PLANS

Certain employees are eligible to receive supplemental benefits under both the defined benefit and defined contribution plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and are secured by letters of credit.

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

OTHER POST-EMPLOYMENT BENEFITS

The Company provides retired employees with other post-employment benefits that include, depending on circumstances, supplemental health, and life insurance coverage. Post-employment benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health care cost escalation. The most recent actuarial valuations were completed as at December 31, 2002. The expected weighted average remaining service life of employees covered by these benefit plans is 9.0 years (2003 - 9.0 years).

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 each year. The financial positions of the employee defined benefit pension plans and other benefit plans are presented in the tables below:

	Pension benefit plans		Other benefit plans	
	2004	2003	**2004**	2003
Plan assets				
Fair value, beginning of year	**$ 169.8**	$ 146.8	**$ -**	$ -
Transfer to parent	**(2.4)**	-	**-**	-
Actual return on plan assets	**19.2**	20.5	**-**	-
Employers' contributions	**3.7**	7.4	**0.8**	0.6
Employees' contributions	**2.4**	2.4	**-**	-
Benefits and settlements paid	**(7.4)**	(7.1)	**(0.8)**	(0.6)
Other	**(0.1)**	(0.2)	**-**	-
Fair value, end of year	**185.2**	169.8	**-**	-
Accrued benefit obligation				
Obligation, beginning of year	**189.4**	171.4	**48.5**	36.0
Transfer to parent	**(12.0)**	-	**(0.8)**	-
Current service cost	**4.8**	5.5	**0.8**	0.9
Interest cost	**11.1**	11.3	**3.0**	2.4
Employees' contributions	**2.4**	2.4	**-**	-
Benefits and settlements paid	**(7.4)**	(7.1)	**(0.8)**	(0.6)
Change in discount rate	**3.2**	3.6	**2.1**	2.0
Actuarial loss	**-**	1.0	**-**	10.8
Past service cost and other	**0.2**	1.3	**0.1**	(3.0)
Balance, end of year	**191.7**	189.4	**52.9**	48.5
Funded status - plan deficit	**(6.5)**	(19.6)	**(52.9)**	(48.5)
Unamortized transitional obligation (benefit)	**(14.0)**	(16.7)	**6.2**	7.8
Unamortized actuarial loss	**21.1**	29.4	**23.4**	23.9
Unamortized past service costs	**3.8**	6.3	**(1.0)**	(1.3)
Accrued benefit asset (liability)	**$ 4.4**	$ (0.6)	**$ (24.3)**	$ (18.1)

The net accrued benefit liability is included in other long-term liabilities and deferred credits (Note 6).

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

Included in the accrued benefit obligation and fair value of the plan assets at year-end are the following amounts in respect of plans with accrued benefit obligations in excess of fair value of assets:

	Pension benefit plans		Other benefit plans	
	2004	2003	**2004**	2003
Accrued benefit obligations:				
Unfunded plans	**$ 8.4**	$ 17.1	**$ 52.9**	$ 48.5
Funded plans	**137.6**	125.3	**-**	-
	146.0	142.4	**52.9**	48.5
Fair value of plan assets	**136.5**	120.5	**-**	-
Funded status deficit	**$ (9.5)**	$ (21.9)	**$ (52.9)**	$ (48.5)

The accrued benefit obligations for unfunded pension benefit plans are secured by letters of credit.

The net benefit plan expense is as follows:

	Pension benefit plans		Other benefit plans	
	2004	2003	**2004**	2003
Current service cost	**$ 4.8**	$ 5.5	**$ 0.8**	$ 0.9
Interest cost on projected benefit obligations	**11.1**	11.3	**3.0**	2.4
Actual positive return on plan assets	**(19.2)**	(15.0)	**-**	-
Net actuarial losses	**3.2**	2.8	**2.1**	2.2
Past service costs	**0.2**	0.8	**-**	(4.4)
Net benefit plan expense before adjustments	**0.1**	5.4	**5.9**	1.1
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return on plan assets	**7.0**	3.0	**-**	-
Difference between actual and recognized actuarial losses in year	**(1.7)**	(2.4)	**(0.2)**	(12.0)
Difference between actual and recognized past service costs in year	**0.2**	(0.1)	**-**	4.4
Amortization of transitional obligation (benefit)	**(1.8)**	(1.9)	**1.6**	12.8
Other	**1.1**	0.2	**0.1**	-
Net benefit plan expense	**$ 4.9**	$ 4.2	**$ 7.4**	$ 6.3
Defined contribution plan expense	**$ 0.9**	$ 1.1		
	$ 5.8	$ 5.3		

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

BENEFIT PLAN ASSETS

The weighted-average asset allocation by asset category of the Company's defined benefit pension plans and other funded benefit plans is as follows:

	Pension Benefit Plans	
	2004	2003
Equity securities	**54%**	56%
Fixed income securities	**38%**	35%
Other assets	**8%**	9%
Total assets	**100%**	100%

The investment policy for benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Company's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost-effective manner while not compromising the security of the respective plans. The pension plans utilize external investment managers to manage the investment policy. Assets in the plan are held in trust by independent third parties.

The pension plans do not directly hold any shares of the Company's parent.

SIGNIFICANT ASSUMPTIONS

The discount rate assumption used in determining pension and post-retirement benefit obligations and net benefit expense reflects the market yields, as of the measurement date, on high-quality debt instruments. The expected rate of return on plan assets assumption is reviewed annually by management, in conjunction with actuaries. The assumption is based on the expected returns for the various asset classes, weighted by the portfolio allocation.

The weighted average significant actuarial assumptions used to determine the accrued benefit obligation and the benefit plan expense are as follows:

	Pension benefit plans		Other benefit plans	
	2004	2003	**2004**	2003
Accrued benefit obligation				
Discount rate at December 31, based on AA Corporate bonds	**6.00%**	6.25%	**6.25%**	6.50%
Rate of compensation increase	**3.33%**	3.32%	**-**	-
Net benefit plan expense				
Discount rate at January 1, based on AA Corporate bonds	**6.25%**	6.50%	**6.25%**	6.50%
Expected rate of return on plan assets	**7.50%**	7.50%	**-**	-

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

The assumed health-care cost trend rates for other post-employment benefit plans are as follows:

	2004	2003
Extended health benefits		
Initial health care cost trend rate	**9.0%**	10.0%
Annual rate of decline in trend rate	**1.0%**	1.0%
Ultimate health care cost trend rate	**5.0%**	5.0%
Year that the rate reaches the ultimate trend rate	**2008**	2008
Medical Services Plan Benefits Premium trend rate	**4.0%**	4.0%

A one percentage-point change in assumed health-care cost trend rates would have the following effects:

2004	One percentage-point increase	One percentage-point decrease
Effect on the total of the service costs and interest cost components of the benefit plan expense	**$ 0.9**	**$ (0.7)**
Effect on accrued benefit obligation	**10.7**	**(8.9)**

CASH FLOWS

Total cash contributions for employee benefits plans consist of:

	Pension benefit plans	
	2004	2003
Funded plans	**$ 3.3**	$ 6.6
Beneficiaries of unfunded plans	**1.3**	1.5
Defined contribution plans	**0.9**	1.1
Total	**$ 5.5**	$ 9.2

The contributions for 2005 are anticipated to be approximately the same as 2004 for defined pension benefit plans and other benefit plans.

BENEFIT CHANGES

Effective January 1, 2004, the Company modified its post-employment benefit program for non-union active employees in order to provide future retirees with more choice of coverage and to reduce the Company's exposure to future health and group life cost increases. The new plan is predominantly a defined contribution plan incorporating a Company-paid health spending account, a security health plan and life insurance. Provincial medical services plan premiums will now be paid by the retiree.

All plan members who have retired on or before December 31, 2004 receive benefits under the plans that were in effect when they retired, which includes the payment of provincial medical services plan premiums by the Company. Employees electing to retire during 2005 will have a choice between the new and old plan, and employees retiring after December 31, 2005 will participate in the new plan.

These assumptions, including the post-employment benefit plan changes, were included in the calculation of the accrued benefit obligation at December 31, 2003 and 2004.

9. STOCK-BASED COMPENSATION

The Company's parent, Terasen Inc., grants stock options to employees of the Company under its stock option plans. In 2004, 192,200 options (2003 – 148,200 options) to purchase shares in the Company's parent were issued to employees of the Company at an average exercise price of $23.88 (2003 - $19.75). In 2004, the Company was charged, and recorded as an expense, $0.3 million (2003 - $0.1 million) for the fair value of the stock compensation granted in 2004 by Terasen Inc.

10. FINANCING COSTS

	2004	2003
Interest and expense on long-term debt	**$ 99.2**	$ 104.7
Interest on short-term debt	**7.7**	7.8
Interest capitalized	**(0.5)**	(0.6)
	$ 106.4	$ 111.9

11. INCOME TAXES

VARIATION IN EFFECTIVE INCOME TAX RATE

Consolidated income taxes vary from the amount that would be computed by applying the federal and provincial combined statutory income tax rate of 34.58% (2003 – 36.02%) to earnings before income taxes as shown in the following table:

	2004	2003
Earnings before income taxes	**$ 106.2**	$ 109.5
Combined statutory income tax rate	**34.58%**	36.02%
Combined income taxes at statutory rate	**$ 36.7**	$ 39.4
Increase (decrease) in income taxes resulting from:		
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	**(8.4)**	(6.9)
Large Corporations Tax in excess of surtax	**4.3**	5.0
Non-deductible expenses and non-taxable income	**4.2**	3.1
Other	**(1.4)**	(1.5)
Actual consolidated income taxes	**$ 35.4**	$ 39.1
Effective Income Tax Rate	**33.33%**	35.71%

FUTURE INCOME TAXES

As a result of the Company accounting for income taxes following the taxes payable method for its regulated operations, the Company has not recognized net future income tax liabilities amounting to $215.8 million at December 31, 2004 (2003 – $206.1 million) and has not recognized a future income tax expense of $9.7 million for the year ended December 31, 2004 (2003 – $9.8 million), all of which were calculated using the asset and liability method.

12. FINANCIAL INSTRUMENTS

FAIR VALUE ESTIMATES

The carrying values of cash and short-term investments, accounts receivable, bank indebtedness, short-term notes and accounts payable and accrued liabilities approximate their fair values due to the relatively short period to maturity of the instruments.

The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2004, or by using available quoted market prices, is estimated at $1,649.8 million (2003 - $1,480.8 million). The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

DERIVATIVE INSTRUMENTS

The Company uses derivative instruments to hedge its exposures to fluctuations in natural gas prices, interest rates and foreign currency exchange rates.

Asset (Liability)			**2004**		2003	
December 31 (in millions)	Number of swaps	Term to maturity (years)	Carrying Value	Fair Value	Carrying Value	Fair Value
Natural Gas Commodity Swaps	122	Up to 2	**$ 1.7**	**$ (6.8)**	$ (7.4)	$ 4.6
Foreign Currency Swaps	-	-	**-**	**-**	-	(0.9)

The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Because it deals with high credit quality institutions in accordance with established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

13. RELATED PARTY TRANSACTIONS

(a) The Company sold property, plant and equipment totaling $3.1 million in 2004 (2003 – nil) to its parent company, Terasen Inc., at net book value and transferred accrued employee benefit plan liabilities of $6.5 million to its parent in 2004.

(b) The Company received $4.0 million in 2004 (2003 - $3.9 million) from Terasen Gas (Vancouver Island) Inc. ("TGVI"), a subsidiary company of Terasen Inc., for transporting gas through the Company's pipeline system.

(c) The Company paid approximately $42.4 million during the year ended December 31, 2004 (2003 - $42.4 million) for customer care and billing services to a limited partnership. Terasen Inc. holds a 30% interest in the limited partnership and jointly controls it. The Company is committed to pay approximately $42.0 million per year as base contract fees through the end of 2006.

14. RELATED PARTY TRANSACTIONS (CONT'D)

(d) The Company paid $8.6 million in 2004 to its parent company for management services. At the beginning of 2004 employees and assets relating to corporate services were transferred from the Company to Terasen Inc. to separate these functions from the regulated operations. As a result of the separation, a management fee was established that would retain the level of cost as approved in the 2003 revenue requirement. In 2003, $8.6 million of operating expenses were included in the Company's financial results related to these employees and assets.

(e) The Company charged affiliated companies $3.6 million in 2004 (2003 – $0.3 million) for management services. During the fourth quarter of 2003 the Company and TGVI incurred restructuring charges, as disclosed in Note 2, to facilitate the operational integration of the two companies. The integration exercise facilitates a shared services approach that enables both companies to harness the benefits from economies of scale by having a single management and support structure that avoids duplication of work and allows customers to benefit from the synergies created.

14. COMMITMENTS AND CONTINGENCIES

The Company has entered into operating leases for certain building space and natural gas distribution assets. In addition, the Company enters into gas purchase contracts.

The following table sets forth the Company's operating lease and purchase obligations due in the years indicated:

	Operating leases	Purchase obligations	Total
2005	$ 16.0	$ 710.7	$ 726.7
2006	15.7	318.7	334.4
2007	15.2	70.6	85.8
2008	15.8	20.1	35.9
2009	15.7	16.0	31.7
2010 and later	135.0	-	135.0
	$ 213.4	$ 1,136.1	$ 1,349.5

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at December 31, 2004.

On January 4, 2005 the Company terminated an operating lease for a certain building and paid $49.4 million to acquire the related building. Accordingly, payments related to this operating lease are not included in the above table. Effective January 4, 2005 the building is included in property, plant and equipment and has been included in the Company's rate base revenue requirement for 2005.

A number of claims and lawsuits seeking damages and other relief are pending against the Company. Management is of the opinion, based upon information presently available, that it is unlikely that any liability, to the extent not provided for through insurance or otherwise, would be material in relation to the Company's consolidated financial statements.

CONSOLIDATED FINANCIAL STATEMENTS OF

TERASEN GAS INC.

YEARS ENDED DECEMBER 31, 2005 AND 2004

MANAGEMENT'S RESPONSIBILITY

The consolidated financial statements have been prepared by management, which is responsible for the integrity and objectivity of this information. These financial statements have been prepared in conformity with Canadian generally accepted accounting principles and, where appropriate, include some amounts that are based on management's best estimates and judgments. The financial information presented elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established systems of internal control which are designed to provide reasonable assurance that assets are safeguarded from loss and that reliable financial records are maintained. These systems are monitored by internal auditors.

KPMG LLP, the independent auditors, have audited the consolidated financial statements of the Company in accordance with Canadian generally accepted auditing standards and have expressed their opinion upon completion of such audits in the following report. In order to provide their opinion on these consolidated financial statements, the independent auditors review the system of internal controls and conduct their work to the extent they consider appropriate.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the consolidated financial statements for issuance to the shareholders.

Signed: *"R.L. (Randy) Jespersen""*

President

Signed: *"Scott A. Thomson"*

Vice President, Finance and Regulatory
Affairs and Chief Financial Officer

Vancouver, Canada
February 3, 2006

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated statements of financial position of Terasen Gas Inc. as at December 31, 2005 and 2004 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Signed: *“KPMG LLP”*

Chartered Accountants

Vancouver, Canada
February 3, 2006, except as to notes 7 and 15 (a), which are as of
March 2, 2006 and note 15 (b) which is as of
March 31, 2006

CONSOLIDATED STATEMENTS OF EARNINGS

In millions of dollars *Years ended December 31*	**2005**	2004
Revenues		
Natural gas distribution	**$ 1,465.9**	$ 1,305.2
Expenses		
Cost of natural gas	**961.1**	807.0
Operation and maintenance	**169.8**	164.4
Depreciation and amortization	**79.2**	81.6
Property and other taxes	**39.8**	39.6
	1,249.9	1,092.6
Operating income	**216.0**	212.6
Financing costs (note 10)	**111.1**	106.4
Earnings before income taxes	**104.9**	106.2
Current income taxes (note 11)	**39.6**	35.4
Net earnings	**$ 65.3**	$ 70.8

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

In millions of dollars *Years ended December 31*	**2005**	2004
Retained earnings, beginning of year	**$ 38.6**	$ 27.8
Net earnings	**65.3**	70.8
	103.9	98.6
Dividends on common shares	**60.0**	60.0
Retained earnings, end of year	**$ 43.9**	$ 38.6

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

In millions of dollars	**2005**	2004
Assets		
Current assets		
Cash and short-term investments	**$ 15.6**	$ 1.7
Accounts receivable	**401.4**	252.9
Inventories of gas in storage and supplies	**177.9**	151.5
Prepaid expenses	**4.4**	4.0
Current portion of rate stabilization accounts (note 3)	**13.0**	13.8
	612.3	423.9
Property, plant and equipment (note 2)	**2,329.2**	2,260.0
Rate stabilization accounts (note 3)	**25.9**	27.9
Other assets (note 4)	**45.4**	45.5
	$ 3,012.8	$ 2,757.3
Liabilities and shareholders' equity		
Current liabilities		
Short-term notes	**$ 313.0**	$ 107.0
Accounts payable and accrued liabilities	**319.4**	252.1
Income and other taxes payable	**29.6**	18.9
Current portion of rate stabilization account (note 3)	**47.9**	27.6
Current portion of long-term debt (note 5)	**121.7**	397.2
	831.6	802.8
Long-term debt (note 5)	**1,229.9**	1,051.4
Other long-term liabilities and deferred credits (note 6)	**105.1**	93.1
Future income taxes	**0.5**	0.5
	2,167.1	1,947.8
Shareholders' equity		
Share capital (note 7)	**594.0**	594.0
Contributed surplus (note 7)	**207.8**	176.9
Retained earnings	**43.9**	38.6
	845.7	809.5
	$ 3,012.8	$ 2,757.3

Approved by the Board:

Signed: *"James M. Stanford"* Director

Signed: *"Douglas W.G. Whitehead"* Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions of dollars	**2005**	2004
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$ 65.3**	$ 70.8
Adjustments for non-cash items		
Depreciation and amortization	**79.2**	81.6
Other	**8.0**	(0.9)
	152.5	151.5
Change in rate stabilization accounts	**1.9**	24.4
Changes in non-cash working capital	**(46.4)**	15.5
	108.0	191.4
Investing activities		
Property, plant and equipment	**(152.7)**	(93.9)
Proceeds on sale of natural gas distribution assets (note 6)	**7.2**	64.6
Proceeds on sale of property, plant and equipment (note 13(a))	**-**	3.1
Other assets and deferred credits	**2.4**	(2.4)
	(143.1)	(28.6)
Financing activities		
Increase (decrease) in short-term notes	**206.0**	(245.9)
Increase in long-term debt	**301.5**	152.1
Reduction of long-term debt	**(398.5)**	(3.0)
Dividends on common shares	**(60.0)**	(60.0)
	49.0	(156.8)
Increase in cash	**13.9**	6.0
Cash (bank indebtedness) at beginning of year	**1.7**	(4.3)
Cash at end of year	**$ 15.6**	$ 1.7
Supplemental cash flow information		
Interest paid in the year	**$ 113.4**	$ 103.7
Income taxes paid in the year	**9.5**	31.7
Non-cash transactions Mark to market on certain gas derivatives deferred in rate-stabilization accounts	**21.2**	-

Cash is defined as cash or bank indebtedness.

1. SIGNIFICANT ACCOUNTING POLICIES

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses in the financial statements, as well as the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

In the opinion of Management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and reflect the following summary of significant accounting policies.

(a) BASIS OF PRESENTATION

The consolidated financial statements include the accounts of the Company and its subsidiaries, including Terasen Gas (Squamish) Inc. (“Squamish”).

Certain comparative figures have been reclassified to conform with the current year’s presentation.

(b) REGULATION

The Company and Squamish are subject to the regulation of the British Columbia Utilities Commission (“the BCUC”), an independent regulatory authority. The Company has a multi-year agreement that will expire at the end of 2007. This multi-year agreement is a cost-of-service based agreement with allowed rates of return on approved rate base set by the BCUC. For 2005, the Company’s allowed rate of return was 9.03%. The allowed rate of return is based on a notional debt-equity ratio of 67% debt and 33% equity. The Company has an annual review process for rate approvals and allowed rates of return are reset annually, unless directed differently by the BCUC.

The BCUC exercises statutory authority over such matters as rates of return, construction and operation of facilities, accounting practices, rates, and contractual agreements with customers.

In order to recognize the economic effects of regulation, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non-regulated businesses.

The impacts of rate regulation on the Company’s operations for the twelve months ending December 31, 2005 and as at December 31, 2005 are described in the Significant Accounting Policies, and in Note 2 “Property, Plant and Equipment”, Note 3 “Rate Stabilization Accounts”, Note 4 “Other Assets”, Note 6 “Other Long-Term Liabilities and Deferred Credits”, Note 8 “Employee Benefit Plans”, Note 10 “Financing Costs”, and Note 11 “Income Taxes”.

(c) INVENTORIES

Inventories of gas in storage are valued at weighted-average cost. Supplies and other inventories are valued at the lower of cost and net realizable value.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(d) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures for system expansions, betterments and replacements, an allocation of overhead costs and an allowance for funds used during construction. When allowed by the BCUC, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

Depreciation of regulated assets is recorded on a straight-line basis over their useful lives. Depreciation rates for regulated assets are approved by the respective regulator.

The cost of regulated depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation as is any gain or loss incurred on disposal.

(e) IMPAIRMENT OF LONG-LIVED ASSETS

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

(f) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Company concurrently recognizes a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the life of the asset. The fair value of the asset retirement obligation is estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Changes in the obligation due to the passage of time are recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Company’s natural gas distribution systems are not currently determinable, the Company has not recognized an asset retirement obligation at December 31, 2005 and 2004. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(g) RATE STABILIZATION ACCOUNTS

The Company is authorized by the BCUC to maintain rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility. The Revenue Stabilization Adjustment Mechanism (“RSAM”) accumulates the margin impact of variations in the actual versus forecast use for residential and commercial customers.

In 2004 the Gas Cost Reconciliation Account (“GCRA”), which accumulates differences between actual natural gas costs and forecast natural gas costs as recovered in base rates, was replaced by the Commodity Cost Reconciliation Account (“CCRA”) and the Midstream Cost Reconciliation Account (“MCRA”). The two new accounts were approved by the BCUC to segregate costs that are allocable to all sales customers (MCRA) and all residential customers and certain commercial and industrial customers for whom Terasen Gas acquires gas supply (CCRA).

All rate stabilization account balances are amortized and recovered through rates as approved by the BCUC.

(h) DEFERRED CHARGES

The Company defers certain charges which the regulatory authorities or contractual arrangements require or permit to be recovered through future rates. Deferred charges are amortized over various periods as approved by the BCUC and depending on the nature of the charges.

Deferred charges include long-term debt issue costs which are amortized over the term of the related debt.

Deferred charges not subject to regulation relate to projects which are expected to benefit future periods and will be capitalized on completion, expensed on project abandonment, or amortized over their useful lives.

(i) DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices.

A derivative must be designated and effective to be accounted for as a hedge. The Company designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Company also assesses, both at inception and on an ongoing basis, whether the derivative instruments that are used in each hedging transaction are effective in offsetting changes in fair values or cash flows of the hedged items. Derivatives accounted for as a hedge are not recognized in the consolidated financial statements.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Derivative financial instruments not designated as effective as a hedge are recorded at fair value at the balance sheet date. The carrying amount of these derivatives, which comprise unrealized gains and losses, are included in accounts receivable in the case of contracts in a gain position and accounts payable and accrued liabilities in the case of contracts in a loss position. The offsetting gain/loss is recorded in the rate stabilization accounts, as realized gains/losses are included in rates and passed on to customers.

As approved by the regulator, derivatives are used to manage natural gas price risk in the natural gas distribution operations. The majority of the natural gas supply contracts have floating, rather than fixed prices. The Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in deferral accounts (CCRA and MCRA), and subject to regulatory approval, are passed through in future rates to customers.

Foreign currency risk in natural gas distribution operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through regulatory deferral accounts.

The Company's short-term borrowings and variable rate long-term debt are exposed to interest rate risk.

(j) REVENUE RECOGNITION

The Company recognizes revenues when products have been delivered or services have been performed.

Revenues from natural gas sales are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year and are adjusted for the Revenue Stabilization Adjustment Mechanism and other BCUC approved orders.

(k) POST-EMPLOYMENT BENEFIT PLANS

The Company sponsors a number of employee benefits plans. These plans include both defined benefit and defined contribution pension plans, and various other post-retirement benefit plans.

The cost of pensions and other post-retirement benefits earned by employees is actuarially determined as the employee provides service, except when the BCUC requires costs to be expensed as paid. The Company uses the projected benefit method based on years of service and estimates of expected returns on plan assets, salary escalation, retirement age of employees, mortality and expected future health-care costs. The discount rate used to value liabilities is based on AA Corporate bond yields. The Company accrues the cost of defined benefit pensions and post-employment benefits as the employee provides services, except when the BCUC requires costs to be expensed as paid.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets as of December 31, 2005 is calculated as the average of the market value of invested assets at December 31, 2005 and two actuarially determined extrapolated market values of invested assets at December 31, 2005. The two extrapolated market values are calculated by using the market value of invested assets at December 31, 2003 rolled forward to December 31, 2005 using 2004 and 2005 net contributions and assumed investment returns, and the market value of invested assets at December 31, 2004 rolled forward to December 31, 2005 using 2005 net contributions and assumed investment returns. These three amounts are then averaged and reported as the market-related value of plan assets.

Adjustments, in excess of 10% of the greater of the accrued benefit obligation and plan asset value, that result from plan amendments, changes in assumptions and experience gains and losses, are amortized over the expected average remaining service life of the employee group covered by the plan. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

Defined contribution plan costs are expensed by the Company as contributions are payable.

(l) INCOME TAXES

The Company and Squamish account for and recover income tax expense in rates as prescribed by the BCUC for ratemaking purposes. This includes accounting for income taxes by the taxes payable method and accounting for certain deferral and rate stabilization accounts on a net of realized tax basis, as approved by the BCUC. Therefore, future income taxes related to temporary differences are not recorded. The taxes payable method is followed as there is reasonable expectation that all future income taxes will be recovered in rates when they become payable.

(m) VARIABLE INTEREST ENTITIES

Effective January 1, 2005, the Company adopted the CICA Handbook Accounting Guideline 15 "Consolidation of Variable Interest Entities". The Company has performed a review of the entities with whom it conducts business and has concluded that there are no entities that are required to be consolidated or variable interests that are required to be disclosed under the requirements of the Guideline.

(Tabular amounts in millions of dollars, except where stated otherwise)

2. PROPERTY, PLANT AND EQUIPMENT

2005	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas distribution systems	**2.30%**	**$ 2,623.8**	**$ 546.8**	**$ 2,077.0**
Plant, buildings and equipment	**9.80%**	**277.5**	**106.7**	**170.8**
Land and land rights	**0.00%**	**82.8**	**1.4**	**81.4**
		$ 2,984.1	**$ 654.9**	**$ 2,329.2**

2004	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas distribution systems	2.40%	$ 2,556.0	$ 505.8	$ 2,050.2
Plant, buildings and equipment	9.30%	223.1	94.5	128.6
Land and land rights	0.60%	82.5	1.3	81.2
		$ 2,861.6	$ 601.6	$ 2,260.0

As allowed by the regulators, during the year ended December 31, 2005 the Company capitalized an allowance for equity funds during construction at approved rates of $0.6 million (2004 - $0.4 million) and approved capitalized overhead of $26.3 million (2004 - $26.1 million), with offsetting inclusions in earnings.

3. RATE STABILIZATION ACCOUNTS

	2005	2004
Current Assets		
RSAM	**$ 13.0**	$ 11.1
CCRA	**-**	2.7
	13.0	13.8
Long-Term Assets		
RSAM	**25.9**	27.9
	38.9	27.9
Current Liabilities		
CCRA	**(21.3)**	-
MCRA	**(26.6)**	(27.6)
	(47.9)	(27.6)
Net rate stabilization accounts	**$ (9.0)**	$ 14.1

The current portion of the rate stabilization accounts represents the amounts expected to be recovered or refunded in rates over the next twelve months. Actual recoveries/(refunds) will vary depending on natural gas consumption and recovery amounts approved by the BCUC.

(Tabular amounts in millions of dollars, except where stated otherwise)

3. RATE STABILIZATION ACCOUNTS (CONTINUED)

The RSAM account is anticipated to be recovered in rates over three years. Recovery of the RSAM balance is dependent upon annually approved rates and actual gas consumption volumes. The MCRA and CCRA accounts are anticipated to be fully recovered or paid within the next fiscal year.

4. OTHER ASSETS

	2005	2004
Deferred charges		
Subject to rate regulation and approved for recovery in rates		
Income taxes recoverable on post-employment benefits	**$ 10.6**	$ 8.4
Long-term debt issue costs	**7.7**	6.9
Commercial commodity unbundling costs	**3.2**	4.0
Replacement transportation agreement	**3.2**	3.6
Other items approved for recovery in rates	**8.9**	7.0
Subject to rate regulation but not yet approved for recovery in rates		
Inland Pacific Connector Development costs	**-**	5.4
Other items subject to rate regulation but not yet approved	**1.8**	0.3
	35.4	35.6
Investments	**-**	0.3
Long-term receivables	**10.0**	9.6
	$ 45.4	$ 45.5

Amortization of these deferred charges in rates for the year ended December 31, 2005 totalled $7.7 million (2004 - $4.9 million).

The deferral account for income taxes on post-employment benefits relates to income tax amounts on post employment benefit expense. The BCUC allows post-employment benefits to be collected from customers through rates calculated on the accrual basis, rather than a cash paid basis, which produces a timing difference for income tax purposes. Since the Company accounts for income taxes using the taxes payable basis of accounting, the tax effect of this timing difference is included in other assets, and will be reduced as cash payments for post-employment benefits exceed required accruals and amounts collected from customers in rates.

Long-term debt issue costs are amortized over the terms of the related debt, whose maturity dates are provided in Note 5 “Long-Term Debt”.

The commercial commodity unbundling costs deferred are costs incurred to develop a third-party marketer alternative for commercial customers to purchase natural gas from suppliers other than the Company. The BCUC has approved the recovery of these costs in rates over a five-year period, of which four years remain at December 31, 2005.

4. OTHER ASSETS (CONTINUED)

The deferral account for the replacement transportation agreement relates to amounts that the Company is allowed to recover from customers in rates in order to cover any shortfall in revenues relative to a minimum amount approved by the BCUC on the Company's Southern Crossing Pipeline. The deferral account is being amortized and recovered in rates over a five-year period, of which four years remain at December 31, 2005.

Deferred charges and deferred credits for rate regulated entities that have been aggregated in the table above and in Note 6 relate to more than fifty deferral accounts, none of which exceed $1.6 million individually. All of these accounts have been approved by regulators in prior annual rate approvals or orders and are being amortized over various periods depending on the nature of the costs.

On October 5, 2005, the BCUC issued a decision that denied recovery of approximately $5.4 million of costs that the Company incurred to develop the Inland Pacific Connector pipeline project that is planned to bring new gas transmission capacity to the Lower Mainland of British Columbia when economic conditions make the project viable. The Company still believes that the project is viable and intends to keep all existing permits and land right approvals in place that have already been granted. The Company has filed an application to have the decision reconsidered, but has recorded an after-tax provision of $3.6 million at December 31, 2005.

(Tabular amounts in millions of dollars, except where stated otherwise)

5. LONG-TERM DEBT

	2005	2004
(a) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2015	**$ 74.9**	$ 74.9
10.30% Series B, due September 30, 2016	**200.0**	200.0
(b) Debentures and Medium Term Note Debentures:		
9.75% Series D, due December 17, 2006	**20.0**	20.0
10.75% Series E, due June 8, 2009	**59.9**	59.9
6.20% Series 9, due June 2, 2008	**188.0**	188.0
6.95% Series 11, due September 21, 2029	**150.0**	150.0
6.50% Series 12, due July 20, 2005	**-**	200.0
6.50% Series 13, due October 16, 2007	**100.0**	100.0
6.15% Series 16, due July 31, 2006	**100.0**	100.0
Floating Rate Series 17, interest rate of 2.93% (2004) due September 26, 2005	**-**	150.0
6.50% Series 18, due May 1, 2034	**150.0**	150.0
5.90% Series 19, due February 26, 2035	**150.0**	-
Floating rate, Series 20, interest rate of 3.36% due October 24, 2007	**150.0**	-
Various series, weighted average interest rate of 9.63% (2004 – 9.63%) due in 2005	**-**	45.0
Obligations under capital leases, at 6.07% (2004 – 6.23%)	**8.8**	10.8
Total long-term debt	**1,351.6**	1,448.6
Less: current portion of long-term debt	**121.7**	397.2
	$ 1,229.9	$ 1,051.4

(a) PURCHASE MONEY MORTGAGES:

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Company's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

(b) DEBENTURES AND MEDIUM TERM NOTE DEBENTURES:

The Company's debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

(Tabular amounts in millions of dollars, except where stated otherwise)

5. LONG-TERM DEBT (CONTINUED)

The Company's Series B Purchase Money Mortgages, Series E Debentures, and Series 11, Series 13, Series 16, Series 18, and Series 19 Medium Term Note Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Required principal repayments over the next five years are as follows:

2006	$ 121.7
2007	251.8
2008	189.8
2009	61.6
2010	1.8

6. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS

	2005	2004
Pension and other post-employment benefit liabilities	**$ 26.3**	$ 19.9
Deferred gains on sale of natural gas distribution assets	**59.2**	60.3
Deferred credits		
Subject to rate regulation and approved for recovery in rates		
Earnings Sharing Mechanism	**8.8**	1.6
Deferred Interest Mechanism	**2.4**	2.5
Other items approved for recovery in rates	**6.8**	7.8
Other deferred credits subject to rate regulation	**1.6**	1.0
	$ 105.1	$ 93.1

The deferred gains on sale of natural gas distribution assets occurred upon the sale of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $70.5 million on combined cash proceeds of $141.1 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 14.

Amortization of these deferred credits in rates for the year ended December 31, 2005 totalled $4.5 million (2004 - $3.8 million).

The Earnings Sharing Mechanism is a mechanism agreed to in the Company's multi-year agreement to share, on a 50/50 basis, amounts earned by the Company on its regulated activities that exceed or are less than amounts allowed by the BCUC in the cost-of-service allowed return calculations. These amounts are shared on an after-tax basis, and are returned to customers in rates.

(Tabular amounts in millions of dollars, except where stated otherwise)

6. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS (CONTINUED)

The Company has a deferred interest mechanism which has been approved by the BCUC which requires that variances due to differences in long-term and short-term borrowings and interest rates from those that have been approved in rates be returned to customers in future rates. The impact of this mechanism was to increase financing costs for the year ended December 31, 2005 by $2.0 million (2004 - $1.4 million). The balance of the account is being amortized on a straight-line basis over three years.

7. SHARE CAPITAL

The Company is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

	2005	2004
Common shares, 59,591,732 shares issued	**$ 594.0**	$ 594.0

CONTRIBUTED SURPLUS

Income tax benefits in the amount of $30.9 million (2004 - $33.7 million) relating to transactions with entities under common control were recorded as a credit to contributed surplus in 2005.

DIVIDEND POLICY

As part of its approval of the acquisition of Terasen Inc. by Kinder Morgan, Inc., the BCUC imposed a number of conditions intended to ring-fence the Company from its parent companies. These restrictions included a prohibition on the payment of dividends unless the Company has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. As a result of this and the Decision issued by the BCUC on March 2, 2006 described in Note 15, the Company must maintain a percentage of common equity to total capital that is at least as much as that determined by the BCUC from time to time for ratemaking purposes. Dividends from the Company will not be allowed by the regulator if the requisite equity is not in place. The Company’s dividend policy is intended to ensure that it maintains at least as much common equity as that deemed by the BCUC for rate-making purposes.

8. EMPLOYEE BENEFIT PLANS

The Company is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. The Company also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan:

DEFINED BENEFIT PLANS

Retirement benefits under the defined benefit plans are based on employees' years of credited service and remuneration. Company contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were at December 31, 2002 and December 31, 2004 and the dates of the next required valuations are December 31, 2005 and December 31, 2007. The December 31, 2005 valuations will not be completed until the second quarter of 2006. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 9.5 years (2004 - 9.5 years).

DEFINED CONTRIBUTION PLAN

Effective in 2000 all new non-union employees become members of defined contribution pension plans. Company contributions to the plan are based upon employee age and pensionable earnings.

SUPPLEMENTAL PLANS

Certain employees are eligible to receive supplemental benefits under both the defined benefit and defined contribution plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and are secured by letters of credit.

OTHER POST-EMPLOYMENT BENEFITS

The Company provides retired employees with other post-employment benefits that include, depending on circumstances, supplemental health, and life insurance coverage. Post-employment benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health care cost escalation. The most recent actuarial valuations were completed as at December 31, 2002 and the date of the next required valuation is December 31, 2005 which will not be completed until the second quarter of 2006. The expected weighted average remaining service life of employees covered by these benefit plans is 9.0 years (2004 - 9.0 years).

(Tabular amounts in millions of dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 each year. The financial positions of the employee defined benefit pension plans and other benefit plans are presented in the tables below:

	Defined benefit pension plans		Other benefit plans	
	2005	2004	**2005**	2004
Plan assets				
Fair value, beginning of year	**$ 185.2**	$ 169.8	$ -	$ -
Transfer to parent	**-**	(2.4)	**-**	-
Actual return on plan assets	**18.9**	19.2		-
Company contributions	**4.3**	3.7	**0.9**	0.9
Contributions by members	**2.9**	2.4	**-**	-
Benefits and settlements paid	**(8.8)**	(7.4)	**(0.8)**	(0.8)
Other	**(0.1)**	(0.1)	**(0.1)**	(0.1)
Fair value, end of year	**202.4**	185.2	**-**	-
Accrued benefit obligation				
Obligation, beginning of year	**191.7**	189.4	**52.9**	48.5
Transfer to parent	**-**	(12.0)	**-**	(0.8)
Current service cost	**5.1**	4.8	**0.9**	0.9
Interest cost	**11.5**	11.1	**3.2**	3.0
Contributions by members	**2.8**	2.4	**-**	-
Benefits and settlements paid	**(8.8)**	(7.4)	**(0.8)**	(0.8)
Actuarial losses	**0.6**	-	**-**	-
Change in discount rate	**10.6**	3.2	**8.1**	2.1
Past service cost and other	**0.2**	0.2	**-**	0.1
Balance, end of year	**213.7**	191.7	**64.3**	52.9
Funded status - plan deficit	**(11.3)**	(6.5)	**(64.3)**	(52.9)
Unamortized transitional obligation (benefit)	**(12.2)**	(14.0)	**4.7**	6.2
Unamortized actuarial loss	**24.7**	21.1	**29.5**	23.4
Unamortized past service costs	**3.6**	3.8	**(1.0)**	(1.0)
Accrued benefit asset (liability)	**$ 4.8**	$ 4.4	**$ (31.1)**	$ (24.3)

The net accrued benefit liability is included in other long-term liabilities and deferred credits (Note 6).

(Tabular amounts in millions of dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

Included in the accrued benefit obligation and fair value of the plan assets at year-end are the following amounts in respect of plans with accrued benefit obligations in excess of fair value of assets:

	Pension benefit plans		Other benefit plans	
	2005	2004	**2005**	2004
Accrued benefit obligations:				
Unfunded plans	**$ 10.2**	$ 8.4	**$ 64.3**	**$ 52.9**
Funded plans	**153.0**	137.6	**-**	-
	163.2	146.0	**64.3**	52.9
Fair value of plan assets	**150.1**	136.5	**-**	-
Funded status deficit	**$ (13.1)**	$ (9.5)	**$ (64.3)**	$ (52.9)

The accrued benefit obligations for unfunded pension benefit plans are secured by letters of credit.

The net benefit plan expense is as follows:

	Pension benefit plans		Other benefit plans	
	2005	2004	**2005**	2004
Current service cost	**$ 5.1**	$ 4.8	**$ 0.9**	$ 0.8
Interest cost on projected benefit obligations	**11.5**	11.1	**3.2**	3.0
Actual positive return on plan assets	**(18.9)**	(19.2)	**-**	-
Net actuarial losses	**11.2**	3.2	**8.1**	2.1
Past service costs	**0.3**	0.2	**0.1**	-
Net benefit plan expense before adjustments	**9.2**	0.1	**12.3**	5.9
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return on plan assets	**6.1**	7.0	**-**	-
Difference between actual and recognized actuarial losses in year	**(9.9)**	(1.7)	**(6.1)**	(0.2)
Difference between actual and recognized past service costs in year	**0.3**	0.2	**(0.1)**	-
Amortization of transitional obligation (benefit)	**(1.8)**	(1.8)	**1.6**	1.6
Other	**-**	1.1	**-**	0.1
Net benefit plan expense	**$ 3.9**	$ 4.9	**$ 7.7**	$ 7.4
Defined contribution plan expense	**$ 1.0**	$ 0.9		
	$ 4.9	$ 5.8		

(Tabular amounts in millions of dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

BENEFIT PLAN ASSETS

The weighted-average asset allocation by asset category of the Company's defined benefit pension plans and other funded benefit plans is as follows:

	Defined Benefit Pension Plans	
	2005	2004
Equity securities	**58%**	54%
Fixed income securities	**34%**	38%
Other assets	**8%**	8%
Total assets	**100%**	100%

The investment policy for benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Company's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost-effective manner while not compromising the security of the respective plans. The pension plans utilize external investment managers to manage the investment policy. Assets in the plan are held in trust by independent third parties.

The pension plans do not directly hold any shares of the Company's parent.

SIGNIFICANT ASSUMPTIONS

The discount rate assumption used in determining pension and post-retirement benefit obligations and net benefit expense reflects the market yields, as of the measurement date, on high-quality debt instruments. The expected rate of return on plan assets assumption is reviewed annually by management, in conjunction with actuaries. The assumption is based on the expected returns for the various asset classes, weighted by the portfolio allocation.

The weighted average significant actuarial assumptions used to determine the accrued benefit obligation and the benefit plan expense are as follows:

	Pension benefit plans		Other benefit plans	
	2005	2004	**2005**	2004
Accrued benefit obligation				
Discount rate at December 31, based on AA Corporate bonds	**5.00%**	6.00%	**5.00%**	6.00%
Rate of compensation increase	**3.36%**	3.33%	**-**	-
Net benefit plan expense				
Discount rate at January 1, based on AA Corporate bonds	**6.00%**	6.25%	**6.00%**	6.25%
Expected rate of return on plan assets	**7.50%**	7.50%	**-**	-

(Tabular amounts in millions of dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

The assumed health-care cost trend rates for other post-employment benefit plans are as follows:

	2005	2004
Extended health benefits		
Initial health care cost trend rate	**8.0%**	9.0%
Annual rate of decline in trend rate	**1.0%**	1.0%
Ultimate health care cost trend rate	**5.0%**	5.0%
Year that the rate reaches the ultimate trend rate	**2008**	2008
Medical Services Plan Benefits Premium trend rate	**4.0%**	4.0%

A one percentage-point change in assumed health-care cost trend rates would have the following effects:

2005	One percentage-point increase	One percentage-point decrease
Effect on the total of the service costs and interest cost components of the benefit plan expense	**$ 1.3**	**$ (1.0)**
Effect on accrued benefit obligation	**12.6**	**(10.5)**

CASH FLOWS

Total cash contributions for employee benefit plans consist of:

	Employee benefit plans	
	2005	2004
Funded plans	**$ 3.8**	$ 3.3
Beneficiaries of unfunded plans	**1.4**	1.3
Defined contribution plans	**1.0**	0.9
Total	**$ 6.2**	$ 5.5

The contributions for 2006 are anticipated to be approximately the same as 2005 for defined pension benefit plans and other benefit plans.

BENEFIT CHANGES

Effective January 1, 2004, the Company modified its post-employment benefit program for non-union active employees in order to provide future retirees with more choice of coverage and to reduce the Company's exposure to future health and group life cost increases. The new plan is predominantly a defined contribution plan incorporating a Company-paid health spending account, a security health plan and life insurance. Provincial medical services plan premiums will now be paid by the retiree.

(Tabular amounts in millions of dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

All plan members who have retired on or before December 31, 2004 receive benefits under the plans that were in effect when they retired, which includes the payment of provincial medical services plan premiums by the Company. Employees who retired during 2005 had a choice between the new and old plan, and employees retiring after December 31, 2005 will participate in the new plan.

These assumptions, including the post-employment benefit plan changes, were included in the calculation of the accrued benefit obligation at December 31, 2003.

IMPACT OF RATE REGULATION

As required by the regulator, the Company is required under its approved cost of service model to defer the amounts of pension benefit expense that exceed or are less than the amounts approved by the regulator to be recovered in rates each year. During the year ended December 31, 2005 the Company has deferred pension expense of $0.3 million that exceeded the amount approved by the regulator to be recovered in rates for 2005.

9. STOCK-BASED COMPENSATION

The Company's parent, Terasen Inc., granted stock options to employees of the Company under its stock option plans until November 30, 2005, when all of the outstanding shares of Terasen Inc. were purchased by Kinder Morgan, Inc. In 2005, 164,500 options (2004 – 192,200 options) to purchase shares in Terasen Inc. were issued to employees of the Company at an average exercise price of $29.45 (2004 - $23.88). In 2005, the Company was charged, and recorded as an expense, $0.4 million (2004 - $0.3 million) for the fair value of the stock compensation granted in 2005 by Terasen Inc.

10. FINANCING COSTS

	2005	2004
Interest and expense on long-term debt	**$ 102.4**	$ 99.2
Interest on short-term debt	**9.3**	7.7
Interest capitalized	**(0.6)**	(0.5)
	$ 111.1	$ 106.4

As allowed by the regulators, during the year ended December 31, 2005, the Company capitalized interest for borrowing requirements for construction of assets that have not been included in rate base of $0.6 million (2004 - $0.5 million).

(Tabular amounts in millions of dollars, except where stated otherwise)

11. INCOME TAXES

VARIATION IN EFFECTIVE INCOME TAX RATE

Consolidated income taxes vary from the amount that would be computed by applying the federal and provincial combined statutory income tax rate of 33.97% (2004 – 34.58%) to earnings before income taxes as shown in the following table:

	2005	2004
Earnings before income taxes	**$ 104.9**	$ 106.2
Combined statutory income tax rate	**33.97%**	34.58%
Combined income taxes at statutory rate	**$ 35.7**	$ 36.7
Increase (decrease) in income taxes resulting from:		
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	**(1.5)**	(8.4)
Large Corporations Tax in excess of surtax	**3.7**	4.3
Non-deductible expenses and non-taxable income	**3.6**	4.2
Other	**(1.9)**	(1.4)
Actual consolidated income taxes	**$ 39.6**	$ 35.4
Effective Income Tax Rate	**37.75%**	33.33%

FUTURE INCOME TAXES

As a result of the Company accounting for income taxes following the taxes payable method for its regulated operations, the Company has not recognized net future income tax liabilities amounting to $230.9 million at December 31, 2005 (2004 – $215.8 million) and has not recognized a future income tax expense of $15.1 million for the year ended December 31, 2005 (2004 – $9.7 million), all of which were calculated using the asset and liability method.

12. FINANCIAL INSTRUMENTS

FAIR VALUE ESTIMATES

The carrying values of cash and short-term investments, accounts receivable, short-term notes and accounts payable and accrued liabilities approximate their fair values due to the relatively short period to maturity of the instruments.

12. FINANCIAL INSTRUMENTS (CONTINUED)

The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2005, or by using available quoted market prices, is estimated at $1,580.7 million (2004 - $1,649.8 million). The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

DERIVATIVE INSTRUMENTS

The Company uses derivative instruments to hedge its exposures to fluctuations in natural gas prices, interest rates and foreign currency exchange rates.

Asset (Liability)			**2005**		2004	
December 31 *(in millions)*	Number of swaps and options	Term to maturity (years)	Carrying Value	Fair Value	Carrying Value	Fair Value
Natural Gas						
Commodity Swaps and Options	145	Up to 3	**$ 21.2**	**$ 97.9**	$ -	$ (6.8)
Interest Swaps	3	Up to 2	**-**	**(1.6)**	-	-

The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

Included in the carrying value of the natural gas derivatives is $22.2 million of unrealized fair value gains associated with derivative instruments which were deemed to be ineffective at December 31, 2005 and $1.0 million of derivative instruments which did not qualify for hedge accounting that are in a liability position.

The derivatives entered into by the Company relate to regulated operations and any resulting gains or losses are recorded in rate stabilization accounts, subject to regulatory approval, and passed through to customers in future rates.

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Because it deals with high credit quality institutions in accordance with established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

(Tabular amounts in millions of dollars, except where stated otherwise)

13. RELATED PARTY TRANSACTIONS

(a) The Company sold property, plant and equipment totaling $3.1 million in 2004 to its parent company, Terasen Inc., at net book value and transferred accrued employee benefit plan liabilities of $6.5 million to its parent in 2004.

(b) The Company received $4.1 million in 2005 (2004 – $4.0 million) from Terasen Gas (Vancouver Island) Inc. (“TGVI”), a subsidiary company of Terasen Inc., for transporting gas through the Company’s pipeline system.

(c) The Company paid approximately $43.6 million during the year ended December 31, 2005 (2004 – $42.4 million) for customer care and billing services to a limited partnership. Terasen Inc. holds a 30% interest in the limited partnership and jointly controls it. The Company is committed to pay approximately $42.0 million per year as base contract fees through the end of 2006.

(d) The Company paid $8.7 million in 2005 (2004 – $8.6 million) to its parent company for management services. At the beginning of 2004 employees and assets relating to corporate services were transferred from the Company to Terasen Inc. to separate these functions from the regulated operations. As a result of the separation, a management fee was established that would retain the level of cost as approved in the 2003 revenue requirement.

(e) The Company charged affiliated companies $5.6 million in 2005 (2004 – $3.6 million) for management services.

14. COMMITMENTS AND CONTINGENCIES

The Company has entered into operating leases for certain building space and natural gas distribution assets. In addition, the Company enters into gas purchase contracts.

The following table sets forth the Company’s operating lease and gas purchase obligations due in the years indicated:

	Operating leases	Purchase obligations	Total
2006	$ 16.4	$ 808.9	$ 825.3
2007	16.0	113.6	129.6
2008	16.4	33.2	49.6
2009	16.3	30.2	46.5
2010	16.0	-	16.0
2011 and later	124.6	-	124.6
	$ 205.7	$ 985.9	$ 1,191.6

14. COMMITMENTS AND CONTINGENCIES (CONTINUED)

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at December 31, 2005.

A number of claims and lawsuits seeking damages and other relief are pending against the Company. Management is of the opinion, based upon information presently available, that it is unlikely that any liability, to the extent not provided for through insurance or otherwise, would be material in relation to the Company's consolidated financial statements.

15. SUBSEQUENT EVENT

(a) On March 2, 2006 a Decision was issued by the BCUC approving changes to the Company's deemed equity components from 33% to 35%, with effect from January 1, 2006. The same Decision also modified the previously existing generic return on equity ("ROE") reset formula resulting in an increase in allowed ROE's from the levels that would have resulted from the old formula. The changes increased the allowed ROE for 2006 from 8.29% to 8.80% for the Company.

(b) Subsequent to year-end, the Company received a letter dated March 31, 2006 from the British Columbia Social Service tax authority indicating their intention to assess additional provincial sales tax on the Southern Crossing Pipeline which was completed in 2000. The letter received does not indicate the amount to be assessed and a formal notice of assessment has not been received. Any assessment will be appealed when it is received and the Company believes this assessment is without merit and it will not have a material adverse impact on the financial results of the Company.

CONSOLIDATED FINANCIAL STATEMENTS OF

TERASEN GAS INC.

YEARS ENDED DECEMBER 31, 2006 AND 2005

MANAGEMENT'S REPORT

Financial Reporting

Management is responsible for the accompanying consolidated financial statements. These financial statements have been prepared in conformity with Canadian generally accepted accounting principles and, where appropriate, include amounts that are based on management's best estimates and judgments.

The Board of Directors, through its Audit Committee, oversees Management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to the Company's Management regarding the preparation and presentation of the consolidated financial statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2006. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework to evaluate the effectiveness of the Company's internal control over financial reporting. Based on our evaluation, Management has concluded that the Company's internal control over financial reporting was effective as at December 31, 2006.

The Company's independent auditors, PricewaterhouseCoopers LLP, conduct an audit in accordance with Canadian generally accepted auditing standards. Their report outlines the scope of their audit and gives their opinion on the consolidated financial statements.

Signed: *"R.L. (Randy) Jespersen*

President

Signed: *"Scott A. Thomson"*

Vice President, Finance and Regulatory
Affairs and Chief Financial Officer

Vancouver, Canada
March 29, 2007

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
PricewaterhouseCoopers Place
250 Howe Street, Suite 700
Vancouver, British Columbia
Canada V6C 3S7
Telephone +1 604 806 7000
Facsimile +1 604 806 7806

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated statements of financial position of Terasen Gas Inc. as at December 31, 2006 and the consolidated statements of earnings, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements as at December 31, 2005 and for the year then ended were audited by other auditors who expressed an opinion without reservation on those statements in their report dated February 3, 2006, except as to notes 7 and 15 (a), which are as of March 2, 2006 and note 15 (b) which is as of March 31, 2006.

(Signed) PricewaterhouseCoopers LLP

Chartered Accountants
Vancouver, British Columbia
March 29, 2007

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

TERASEN GAS INC.

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

YEARS ENDED DECEMBER 31, 2006 AND 2005

CONSOLIDATED STATEMENTS OF EARNINGS

Years ended December 31	**2006**	2005
Revenues		
Natural gas distribution	**$ 1,525.3**	$ 1,465.9
Expenses		
Cost of natural gas	**1,008.7**	961.1
Operation and maintenance	**173.9**	169.8
Depreciation and amortization	**83.9**	79.2
Property and other taxes	**41.6**	39.8
	1,308.1	1,249.9
Operating income	**217.2**	216.0
Financing costs (note 10)	**105.2**	111.1
Earnings before income taxes	**112.0**	104.9
Current income taxes (note 11)	**43.6**	39.6
Net earnings	**$ 68.4**	$ 65.3

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Years ended December 31	**2006**	2005
Retained earnings, beginning of year	**$ 43.9**	$ 38.6
Net earnings	**68.4**	65.3
	112.3	103.9
Dividends on common shares	**40.0**	60.0
Retained earnings, end of year	**$ 72.3**	$ 43.9

The accompanying notes are an integral part of these consolidated financial statements.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	2006	2005
Assets		
Current assets		
Cash and short-term investments	**$ 6.5**	$ 15.6
Accounts receivable	**290.3**	401.4
Inventories of gas in storage and supplies	**168.3**	177.9
Prepaid expenses	**5.2**	4.4
Current portion of rate stabilization accounts (note 3)	**118.1**	13.0
	588.4	612.3
Property, plant and equipment (note 2)	**2,352.9**	2,329.2
Rate stabilization accounts (note 3)	**24.7**	25.9
Other assets (note 4)	**62.2**	50.3
	$ 3,028.2	$ 3,017.7
Liabilities and shareholders' equity		
Current liabilities		
Short-term notes	**$ 217.0**	$ 313.0
Accounts payable and accrued liabilities	**407.7**	319.4
Income and other taxes payable	**30.6**	29.6
Current portion of rate stabilization account (note 3)	**-**	47.9
Current portion of long-term debt (note 5)	**251.4**	121.7
	906.7	831.6
Long-term debt (note 5)	**1,098.6**	1,229.9
Other long-term liabilities and deferred credits (note 6)	**121.0**	110.0
Future income taxes	**0.5**	0.5
	2,126.8	2,172.0
Shareholders' equity		
Share capital (note 7)	**594.0**	594.0
Contributed surplus (note 7)	**235.1**	207.8
Retained earnings	**72.3**	43.9
	901.4	845.7
	$ 3,028.2	$ 3,017.7

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board:

Signed: *"James M. Stanford"* Director

Signed: *"R.L. (Randy) Jespersen"* Director

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

CONSOLIDATED STATEMENTS OF CASH FLOWS

	2006	2005
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$ 68.4**	$ 65.3
Adjustments for non-cash items		
Depreciation and amortization	**83.9**	79.2
Other	**7.9**	8.0
	160.2	152.5
Change in rate stabilization accounts	**4.0**	1.9
Changes in working capital	**80.6**	(46.4)
	244.8	108.0
Investing activities		
Property, plant and equipment	**(108.7)**	(152.7)
Proceeds on sale of natural gas distribution assets (note 6)	**-**	7.2
Other assets and deferred credits	**(7.7)**	2.4
	(116.4)	(143.1)
Financing activities		
(Decrease) increase in short-term notes	**(96.0)**	206.0
Increase in long-term debt	**120.0**	301.5
Reduction of long-term debt	**(121.5)**	(398.5)
Dividends on common shares	**(40.0)**	(60.0)
	(137.5)	49.0
(Decrease) increase in cash	**(9.1)**	13.9
Cash at beginning of year	**15.6**	1.7
Cash at end of year	**$ 6.5**	$ 15.6
Supplemental cash flow information		
Interest paid in the year	**$ 106.0**	$ 113.4
Income taxes paid in the year	**14.7**	9.5
Non-cash transactions		
Mark to market on certain gas derivatives deferred in rate-stabilization accounts	**$ 155.9**	21.2

Cash is defined as cash or bank indebtedness.

The accompanying notes are an integral part of these consolidated financial statements.

1. SIGNIFICANT ACCOUNTING POLICIES

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses in the financial statements, as well as the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

In the opinion of Management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and reflect the following summary of significant accounting policies.

(a) BASIS OF PRESENTATION

The consolidated financial statements include the accounts of the Company and its subsidiaries, including Terasen Gas (Squamish) Inc. (“Squamish”).

Certain comparative figures have been reclassified to conform with the current year’s presentation.

(b) REGULATION

The Company and Squamish are subject to the regulation of the British Columbia Utilities Commission (“the BCUC”), an independent regulatory authority. The Company has a multi-year agreement that will expire at the end of 2007. This multi-year agreement is a cost-of-service based agreement with allowed rates of return on approved rate base set by the BCUC. On March 2, 2006 a decision was issued by the BCUC approving changes to the Company’s deemed equity components from 33% to 35%, with effect from January 1, 2006. The same decision also modified the previously existing generic return on equity (“ROE”) reset formula resulting in an increase in allowed ROE’s from the levels that would have resulted from the old formula. The changes increased the allowed ROE for 2006 from 8.29% to 8.80% for the Company. For 2007, the allowed ROE was set at 8.37%.

The allowed rate of return is based on a notional debt-equity ratio of 65% debt and 35% equity. The Company has an annual review process for rate approvals and allowed rates of return are reset annually, unless directed differently by the BCUC.

The BCUC exercises statutory authority over such matters as rates of return, construction and operation of facilities, accounting practices, rates, and contractual agreements with customers.

In order to recognize the economic effects of regulation, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non-regulated businesses.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, GAAP would not permit the recognition of regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in other assets whereas current regulatory assets are recorded in accounts receivable. Regulatory liabilities are recorded in other long-term liabilities and deferred credits.

The impacts of rate regulation on the Company's operations for the twelve months ending December 31, 2006 and as at December 31, 2006 are described in the Significant Accounting Policies, and in Note 2 "Property, Plant and Equipment", Note 3 "Rate Stabilization Accounts", Note 4 "Other Assets", Note 6 "Other Long-Term Liabilities and Deferred Credits", Note 8 "Employee Benefit Plans", Note 10 "Financing Costs", and Note 11 "Income Taxes".

(c) INVENTORIES

Inventories of gas in storage are valued at weighted-average cost. The cost of gas in storage is recovered from customers in future rates. Supplies and other inventories are valued at the lower of cost and net realizable value.

(d) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures for system expansions, betterments and replacements, an allocation of overhead costs and an allowance for funds used during construction. When allowed by the BCUC, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

Depreciation of regulated assets is recorded on a straight-line basis over their useful lives. Depreciation rates for regulated assets are approved by the respective regulator.

The cost of regulated depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation, as is any gain or loss incurred on disposal.

(e) IMPAIRMENT OF LONG-LIVED ASSETS

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(f) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Company concurrently recognizes a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset. The fair value of the asset retirement obligation is estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. Changes in the obligation due to the passage of time are recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Company's natural gas distribution systems are not currently determinable, the Company has not recognized an asset retirement obligation at December 31, 2006 and 2005. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

(g) RATE STABILIZATION ACCOUNTS

The Company is authorized by the BCUC to maintain rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility. The Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual versus forecast use for residential and commercial customers.

The Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The two accounts segregate costs that are allocable to all sales customers (MCRA) and all residential customers and certain commercial and industrial customers for whom Terasen Gas acquires gas supply (CCRA).

All rate stabilization account balances are recovered through rates as approved by the BCUC.

(h) DEFERRED CHARGES

The Company defers certain charges which the regulatory authorities or contractual arrangements require or permit to be recovered through future rates. Deferred charges are amortized over various periods as approved by the BCUC and depending on the nature of the charges.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Deferred charges include long-term debt issue costs which are amortized over the term of the related debt.

Deferred charges not subject to regulation relate to projects which are expected to benefit future periods and will be capitalized on completion, expensed on project abandonment, or amortized over their useful lives.

(i) DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices.

A derivative must be designated and effective to be accounted for as a hedge. The Company designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Company also assesses, both at inception and on an ongoing basis, whether the derivative instruments that are used in each hedging transaction are effective in offsetting changes in fair values or cash flows of the hedged items. Derivatives accounted for as a hedge are not recognized in the consolidated financial statements.

Derivative financial instruments not designated as effective as a hedge are recorded at fair value at the balance sheet date. The carrying amount of these derivatives, which comprise unrealized gains and losses, are included in accounts receivable in the case of contracts in a gain position and accounts payable and accrued liabilities in the case of contracts in a loss position. The offsetting gain/loss is recorded in the rate stabilization accounts, as realized gains/losses are included in rates and passed on to customers.

As approved by the regulator, derivatives are used to manage natural gas price risk in the natural gas distribution operations. The majority of the natural gas supply contracts have floating, rather than fixed prices. The Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in deferral accounts (CCRA and MCRA), and subject to regulatory approval, are passed through in future rates to customers.

Foreign currency risk in natural gas distribution operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through regulatory deferral accounts.

The Company's short-term borrowings and variable rate long-term debt are exposed to interest rate risk. The Company manages interest rate risk through the use of interest rate derivatives with payments and receipts under interest rate swap contracts being recognized as adjustments to financing costs.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(j) REVENUE RECOGNITION

The Company recognizes revenues when products have been delivered or services have been performed.

Revenues from natural gas sales are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year and are adjusted for the RSAM and other BCUC approved orders.

(k) POST-EMPLOYMENT BENEFIT PLANS

The Company sponsors a number of employee benefits plans. These plans include both defined benefit and defined contribution pension plans, and various other post-retirement benefit plans.

The cost of pensions and other post-retirement benefits earned by employees is actuarially determined as the employee provides service, except when the BCUC requires costs to be expensed as paid. The Company uses the projected benefit method based on years of service and estimates of expected returns on plan assets, salary escalation, retirement age of employees, mortality and expected future health-care costs. The discount rate used to value liabilities is based on AA Corporate bond yields. The Company accrues the cost of defined benefit pensions and post-employment benefits as the employee provides services, except when the BCUC requires costs to be expensed as paid.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets as of December 31, 2006 is calculated as the average of the market value of invested assets at December 31, 2006 and two actuarially determined extrapolated market values of invested assets at December 31, 2006. The two extrapolated market values are calculated by using the market value of invested assets at December 31, 2004 rolled forward to December 31, 2006 using 2005 and 2006 net contributions and assumed investment returns, and the market value of invested assets at December 31, 2005 rolled forward to December 31, 2006 using 2006 net contributions and assumed investment returns. These three amounts are then averaged and reported as the market-related value of plan assets.

Adjustments, in excess of 10% of the greater of the accrued benefit obligation and plan asset value, that result from plan amendments, changes in assumptions and experience gains and losses, are amortized over the expected average remaining service life of the employee group covered by the plan. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

Defined contribution plan costs are expensed by the Company as contributions are payable.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(l) INCOME TAXES

The Company and Squamish account for and recover income tax expense in rates as prescribed by the BCUC for ratemaking purposes. This includes accounting for income taxes by the taxes payable method and accounting for certain deferral and rate stabilization accounts on a net of realized tax basis, as approved by the BCUC. Therefore, future income taxes related to temporary differences are not recorded. The taxes payable method is followed as there is reasonable expectation that all future income taxes will be recovered in rates when they become payable.

(m) VARIABLE INTEREST ENTITIES

Effective January 1, 2005, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Accounting Guideline 15 "Consolidation of Variable Interest Entities". The Company has performed a review of the entities with whom it conducts business and has concluded that there are no entities that are required to be consolidated or variable interests that are required to be disclosed under the requirements of the Guideline.

2. PROPERTY, PLANT AND EQUIPMENT

2006

	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas distribution systems	**2.33%**	**$ 2,687.9**	**$ 576.5**	**$ 2,111.4**
Plant, buildings and equipment	**8.25%**	**304.5**	**145.3**	**159.2**
Land and land rights	**0.00%**	**83.6**	**1.3**	**82.3**
		$ 3,076.0	**$ 723.1**	**$ 2,352.9**

2005

	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas distribution systems	2.34%	$ 2,623.8	$ 546.8	$ 2,077.0
Plant, buildings and equipment	9.81%	277.5	106.7	170.8
Land and land rights	0.00%	82.8	1.4	81.4
		$ 2,984.1	$ 654.9	$ 2,329.2

As allowed by the regulators, during the year ended December 31, 2006 the Company capitalized an allowance for equity funds during construction at approved rates of $0.7 million (2005 - $0.6 million) and approved capitalized overhead of $27.2 million (2005 - $26.3 million), with offsetting inclusions in earnings.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

3. RATE STABILIZATION ACCOUNTS

	2006	2005
Current Assets		
RSAM	**$ 11.3**	$ 13.0
CCRA	**81.3**	-
MCRA	**25.5**	-
	118.1	13.0
Long-Term Assets		
RSAM	**24.7**	25.9
	24.7	25.9
Current Liabilities		
CCRA	**-**	(21.3)
MCRA	**-**	(26.6)
	-	(47.9)
Net rate stabilization accounts	**$ 142.8**	$ (9.0)

The current portion of the rate stabilization accounts represents the amounts expected to be recovered or refunded in rates over the next twelve months. Actual recoveries/(refunds) will vary depending on natural gas consumption and recovery amounts approved by the BCUC. Rate stabilization accounts are presented net of tax, where applicable.

The RSAM account is anticipated to be recovered in rates over three years. Recovery of the RSAM balance is dependent upon annually approved rates and actual gas consumption volumes. The MCRA and CCRA accounts are anticipated to be fully recovered or paid within the next fiscal year.

In the absence of rate regulation, the costs in the rate stabilization accounts above would have been expensed as incurred which would have resulted in decreased margin of $230.9 million (2005 – increased $34.3 million), increased natural gas distribution revenues of $4.3 million (2005 - $0.1 million) and decreased income taxes expense of $74.8 million (2005 – increased $11.4 million).

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

4. OTHER ASSETS

	2006	2005
Deferred charges		
Subject to rate regulation and approved for recovery in rates		
Income taxes recoverable on post-employment benefits	**$ 13.1**	$ 10.6
Long-term debt issue costs	**7.8**	7.7
Commercial commodity unbundling costs	**2.5**	3.2
Replacement transportation agreement	**2.2**	3.2
Other items approved for recovery in rates	**8.5**	8.9
Subject to rate regulation but not yet approved for recovery in rates		
Southern Crossing Pipeline PST Reassessment	**10.0**	-
Other items subject to rate regulation but not yet approved	**-**	1.8
	44.1	35.4
Long-term receivables	**9.6**	10.0
Pension assets (Note 8)	**8.5**	4.9
	$ 62.2	$ 50.3

Amortization of these deferred charges in rates for the year ended December 31, 2006 totaled $2.3 million (2005 - $7.7 million).

The deferral account for income taxes on post-employment benefits relates to income tax amounts on post employment benefit expense. The BCUC allows post-employment benefits to be collected from customers through rates calculated on the accrual basis, rather than a cash paid basis, which produces a timing difference for income tax purposes. Since the Company accounts for income taxes using the taxes payable basis of accounting, the tax effect of this timing difference is included in other assets, and will be reduced as cash payments for post-employment benefits exceed required accruals and amounts collected from customers in rates.

Long-term debt issue costs are amortized over the terms of the related debt, whose maturity dates are provided in Note 5 “Long-Term Debt”.

The commercial commodity unbundling costs deferred are costs incurred to develop a third-party marketer alternative for commercial customers to purchase natural gas from suppliers other than the Company. The BCUC has approved the recovery of these costs in rates over a five-year period, of which three years remain at December 31, 2006.

The deferral account for the replacement transportation agreement relates to amounts that the Company is allowed to recover from customers in rates in order to cover any shortfall in revenues relative to a minimum amount approved by the BCUC on the Company’s Southern Crossing Pipeline. The deferral account is being amortized and recovered in rates over a five-year period, of which three years remain at December 31, 2006.

4. OTHER ASSETS (CONTINUED)

The deferral account for the Southern Crossing Pipeline PST reassessment relates to a payment made in regards to a possible assessment of additional provincial sales tax on the Southern Crossing Pipeline. See Note 14.

The Company made a payment of $10 million pending resolution of the appeal as a good faith payment in order to forestall an order from the Province of British Columbia (“the Province”) to provide full payment or security. Depending on the success of the appeal, the Company will either be refunded this payment from the Province or alternatively expects to recover the costs from customers in future rates.

On October 6, 2005, the BCUC issued a decision that denied recovery of approximately $5.4 million of costs that Terasen Gas incurred to develop the Inland Pacific Connector pipeline project that is planned to bring new gas transmission capacity to the Lower Mainland of British Columbia when economic conditions make the project viable. Terasen Gas recorded an after-tax provision of $3.7 million at December 31, 2005. The Company still intends to proceed with the project when market conditions are supportive and intends to keep all existing permits and land right approvals in place that have already been granted. The Company will again seek to recover such costs in the future when it proceeds with the project.

Deferred charges and deferred credits for rate regulated entities that have been aggregated in the table above and in Note 6 relate to more than 40 deferral accounts, none of which exceed $2.0 million individually. All of these accounts have been approved by regulators in prior annual rate approvals or orders and are being amortized over various periods depending on the nature of the costs.

In the absence of rate regulation, the deferred charges in the above table would have been expensed, except from the costs related to the pension asset. This would have resulted in increased income taxes of $2.5 million (2005 - $2.2 million), increased financing costs of $0.1 million (2005 – $0.8 million) and increased operation and maintenance costs of $5.7 million (2005 – $2.6 million).

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

5. LONG-TERM DEBT

	2006	2005
(a) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2015	**$ 74.9**	$ 74.9
10.30% Series B, due September 30, 2016	**200.0**	200.0
(b) Debentures and Medium Term Note Debentures:		
9.75% Series D, due December 17, 2006	**-**	20.0
10.75% Series E, due June 8, 2009	**59.9**	59.9
6.20% Series 9, due June 2, 2008	**188.0**	188.0
6.95% Series 11, due September 21, 2029	**150.0**	150.0
6.50% Series 13, due October 16, 2007	**100.0**	100.0
6.15% Series 16, due July 31, 2006	**-**	100.0
6.50% Series 18, due May 1, 2034	**150.0**	150.0
5.90% Series 19, due February 26, 2035	**150.0**	150.0
Floating rate, Series 20, interest rate of 4.25% (2005 - 3.36%) due October 24, 2007	**150.0**	150.0
5.55% Series 21, due September 25, 2036	**120.0**	-
Obligations under capital leases, at 5.62% (2005 – 6.07%)	**7.2**	8.8
Total long-term debt	**1,350.0**	1,351.6
Less: current portion of long-term debt	**251.4**	121.7
	$ 1,098.6	$ 1,229.9

(a) PURCHASE MONEY MORTGAGES:

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Company's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

(b) DEBENTURES AND MEDIUM TERM NOTE DEBENTURES:

The Company's debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

5. LONG-TERM DEBT (CONTINUED)

The Company's Series B Purchase Money Mortgages, Series E Debentures, and Series 11, Series 13, Series 18, Series 19, and Series 21 Medium Term Note Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Required principal repayments over the next five years are as follows:

2007	$ 251.4
2008	189.4
2009	61.4
2010	1.5
2011	1.5

6. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS

	2006	2005
Pension and other post-employment benefit liabilities (Note 8)	**$ 39.2**	$ 31.2
Deferred gains on sale of natural gas distribution assets	**54.8**	59.2
Deferred credits		
Subject to rate regulation and approved for recovery in rates		
Earnings Sharing Mechanism	**12.6**	8.8
SCP Net Mitigation Revenue	**3.8**	0.8
Large Corporation Tax Elimination	**3.1**	-
Deferred Interest Mechanism	**0.4**	2.4
Other items approved for recovery in rates	**7.1**	6.0
Other deferred credits subject to rate regulation	**-**	1.6
	$ 121.0	$ 110.0

The deferred gains on sale of natural gas distribution assets occurred upon the sale of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $70.5 million on combined cash proceeds of $141.1 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 14.

Amortization of these deferred credits in rates for the year ended December 31, 2006 totaled $4.1 million (2005 - $4.5 million).

The Earnings Sharing Mechanism is a mechanism agreed to in the Company's multi-year agreement to share, on a 50/50 basis, amounts earned by the Company on its regulated activities that exceed or are less than amounts allowed by the BCUC in the cost-of-service allowed return calculations. These amounts are shared on an after-tax basis, and are returned to customers in rates.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

6. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS (CONTINUED)

The SCP Net Mitigation Revenue is revenue that is received from third parties for the use of the SCP transportation capacity that has not been utilized by the firm transportation agreement customers. This account is used to record differences between actual revenues from SCP mitigation and what has been approved in the current revenue requirement. Amounts are being amortized to income over 5 years.

The large corporation tax elimination costs resulted from the British Columbia government eliminating the tax on large corporations in 2006. The BCUC allows large corporation tax to be recovered from customers through rates. These costs were collected from customers through rates in 2006 and now are owed back to customers in future rates upon the elimination of the large corporation tax. The costs will be returned to customers in rates over a three year period beginning January 1, 2007.

The Company has a deferred interest mechanism which has been approved by the BCUC which requires that variances due to differences in long-term borrowings and long-term and short-term interest rates from those that have been approved in rates be returned to customers in future rates. The impact of this mechanism was to decrease financing costs for the year ended December 31, 2006 by $0.6 million (2005 – increase by $2.0 million). The balance of the account is being amortized on a straight-line basis over three years.

In the absence of rate regulation, the other long-term liabilities and deferred credits in the above table would have been expensed, aside for the pension and other post-employment benefit liabilities. This would have resulted in decreased operation and maintenance costs of $1.9 million (2005 - $5.7 million), increased financing costs of $2.0 million (2005 – $0.1 million) and decreased property and other taxes of $3.1 million (2005 – nil).

7. SHARE CAPITAL

The Company is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

	2006	2005
Common shares, 59,591,732 shares issued	**$ 594.0**	$ 594.0

CONTRIBUTED SURPLUS

Income tax benefits in the amount of $27.3 million (2005 - $30.9 million) relating to transactions with entities under common control were recorded as a credit to contributed surplus in 2006.

7. SHARE CAPITAL (CONTINUED)

DIVIDEND POLICY

As part of its approval of the acquisition of Terasen Inc. by Kinder Morgan, Inc., the BCUC imposed a number of conditions intended to ring-fence the Company from its parent companies. These restrictions included a prohibition on the payment of dividends unless the Company has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. As a result of this and the decision issued by the BCUC on March 2, 2006 described in Note 1(b), the Company must maintain a percentage of common equity to total capital that is at least as much as that determined by the BCUC from time to time for ratemaking purposes. Dividends from the Company will not be allowed by the regulator if the requisite equity is not in place. The Company's dividend policy is intended to ensure that it maintains at least as much common equity as that deemed by the BCUC for rate-making purposes.

8. EMPLOYEE BENEFIT PLANS

The Company is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. The Company also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan:

DEFINED BENEFIT PLANS

Retirement benefits under the defined benefit plans are based on employees' years of credited service and remuneration. Company contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were at December 31, 2004 and December 31, 2005 and the dates of the next required valuations are December 31, 2007 and December 31, 2008. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 10.2 years (2005 - 9.5 years).

DEFINED CONTRIBUTION PLAN

Effective in 2000, all new non-union employees became members of defined contribution pension plans. Company contributions to the plan are based upon employee age and pensionable earnings.

SUPPLEMENTAL PLANS

Certain employees are eligible to receive supplemental benefits under both the defined benefit and defined contribution plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and are secured by letters of credit.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

OTHER POST-EMPLOYMENT BENEFITS

The Company provides retired employees with other post-employment benefits that include, depending on circumstances, supplemental health, and life insurance coverage. Post-employment benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health care cost escalation. The most recent actuarial valuations were completed as at December 31, 2005 and the date of the next required valuation is December 31, 2008. The expected weighted average remaining service life of employees covered by these benefit plans is 9.0 years (2005 - 9.0 years).

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 each year. The financial positions of the employee defined benefit pension plans and other benefit plans are presented in the tables below:

	Defined benefit pension plans		Other benefit plans	
	2006	2005	**2006**	2005
Plan assets				
Fair value, beginning of year	**$ 202.4**	$ 185.2	**$ -**	$ -
Actual return on plan assets	**28.6**	18.9	**-**	-
Company contributions	**5.3**	4.3	**1.2**	0.9
Contributions by members	**3.0**	2.9	**-**	-
Benefits and settlements paid	**(10.3)**	(8.8)	**(1.1)**	(0.8)
Other	**(0.1)**	(0.1)	**(0.1)**	(0.1)
Fair value, end of year	**228.9**	202.4	**-**	-
Accrued benefit obligation				
Obligation, beginning of year	**213.7**	191.7	**64.3**	52.9
Current service cost	**5.3**	5.1	**1.2**	0.9
Interest cost	**10.7**	11.5	**3.3**	3.2
Contributions by members	**3.0**	2.8	**-**	-
Benefits and settlements paid	**(10.3)**	(8.8)	**(1.1)**	(0.8)
Actuarial losses	**4.9**	0.6	**0.7**	-
Change in discount rate	**-**	10.6	**-**	8.1
Past service cost and other	**-**	0.2	**(0.2)**	-
Balance, end of year	**227.3**	213.7	**68.2**	64.3
Funded status - plan surplus (deficiency)	**1.6**	(11.3)	**(68.2)**	(64.3)
Unamortized transitional (benefit) obligation	**(10.5)**	(12.2)	**3.1**	4.7
Unamortized actuarial loss	**13.3**	24.7	**27.7**	29.5
Unamortized past service costs	**3.2**	3.6	**(0.9)**	(1.0)
Accrued benefit asset (liability)	**$ 7.6**	$ 4.8	**$ (38.3)**	$ (31.1)
Represented by				
Pension assets	**$ 8.5**	$ 4.9	**$ -**	$ -
Accrued benefit liability	**(0.9)**	(0.1)	**(38.3)**	(31.1)
	$ 7.6	$ 4.8	**$ (38.3)**	$ (31.1)

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

The net accrued benefit liability is included in other long-term liabilities and deferred credits (Note 6) and the pension asset is included in other assets (Note 4).

Included in the accrued benefit obligation and fair value of the plan assets at year-end are the following amounts in respect of plans with accrued benefit obligations in excess of fair value of assets:

	Pension benefit plans		Other benefit plans	
	2006	2005	**2006**	2005
Accrued benefit obligations:				
Unfunded plans	**$ 10.2**	$ 10.2	**$ 68.2**	$ 64.3
Funded plans	**162.2**	153.0	**-**	-
	172.4	163.2	**68.2**	64.3
Fair value of plan assets	**173.0**	150.1	**-**	-
Funded status surplus (deficit)	**$ 0.6**	$ (13.1)	**$ (68.2)**	$ (64.3)

The accrued benefit obligations for unfunded pension benefit plans are secured by letters of credit.

The net benefit plan expense is as follows:

	Pension benefit plans		Other benefit plans	
	2006	2005	**2006**	2005
Current service cost	**$ 5.3**	$ 5.1	**$ 1.2**	$ 0.9
Interest cost on projected benefit obligations	**10.7**	11.5	**3.3**	3.2
Actual positive return on plan assets	**(28.6)**	(18.9)	**-**	-
Net actuarial losses	**4.9**	11.2	**0.7**	8.1
Past service costs	**-**	0.3	**(0.2)**	0.1
Other	**0.1**	-	**0.1**	-
Net benefit plan (income) expense before adjustments	**(7.6)**	9.2	**5.1**	12.3
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return on plan assets	**14.8**	6.1	**-**	-
Difference between actual and recognized actuarial losses in year	**(3.4)**	(9.9)	**1.8**	(6.1)
Difference between actual and recognized past service costs in year	**0.5**	0.3	**-**	(0.1)
Amortization of transitional (benefit) obligation	**(1.8)**	(1.8)	**1.6**	1.6
Other	**-**	-	**-**	-
Net benefit plan expense	**$ 2.5**	$ 3.9	**$ 8.5**	$ 7.7
Defined contribution plan expense	**$ 1.1**	$ 1.0		
	$ 3.6	$ 4.9		

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

BENEFIT PLAN ASSETS

The weighted-average asset allocation by asset category of the Company's defined benefit pension plans and other funded benefit plans is as follows:

	Defined Benefit Pension Plans	
	2006	2005
Equity securities	**58%**	58%
Fixed income securities	**34%**	34%
Other assets	**8%**	8%
Total assets	**100%**	100%

The investment policy for benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Company's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost-effective manner while not compromising the security of the respective plans. The pension plans utilize external investment managers to manage the investment policy. Assets in the plan are held in trust by independent third parties.

The pension plans do not directly hold any shares of the Company's parent.

SIGNIFICANT ASSUMPTIONS

The discount rate assumption used in determining pension and post-retirement benefit obligations and net benefit expense reflects the market yields, as of the measurement date, on high-quality debt instruments. The expected rate of return on plan assets assumption is reviewed annually by management, in conjunction with actuaries. The assumption is based on the expected returns for the various asset classes, weighted by the portfolio allocation.

The weighted average significant actuarial assumptions used to determine the accrued benefit obligation and the benefit plan expense are as follows:

	Pension benefit plans		Other benefit plans	
	2006	2005	**2006**	2005
Accrued benefit obligation				
Discount rate at December 31, based on AA Corporate bonds	**5.00%**	5.00%	**5.00%**	5.00%
Rate of compensation increase for five years and 3.36% thereafter	**3.64%**	3.36%	**-**	-
Net benefit plan expense				
Discount rate at January 1, based on AA Corporate bonds	**5.00%**	6.00%	**5.00%**	6.00%
Expected rate of return on plan assets	**7.25%**	7.50%	**-**	-

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

The assumed health-care cost trend rates for other post-employment benefit plans are as follows:

	2006	2005
Extended health benefits		
Initial health care cost trend rate	**10.0%**	8.0%
Annual rate of decline in trend rate	**1.0%**	1.0%
Ultimate health care cost trend rate	**5.0%**	5.0%
Year that the rate reaches the ultimate trend rate	**2011**	2008
Medical Services Plan Benefits Premium trend rate	**4.0%**	4.0%

A one percentage-point change in assumed health-care cost trend rates would have the following effects:

2006	One percentage-point increase	One percentage-point decrease
Effect on the total of the service costs and interest cost components of the benefit plan expense	**$ 0.6**	**$ (0.5)**
Effect on accrued benefit obligation	**8.2**	**(7.4)**

CASH FLOWS

Total cash contributions for employee benefit plans consist of:

	Employee benefit plans	
	2006	2005
Funded plans	**$ 4.5**	$ 3.8
Beneficiaries of unfunded plans	**2.0**	1.4
Defined contribution plans	**1.1**	1.0
Total	**$ 7.6**	$ 6.2

The contributions for 2007 are anticipated to be approximately the same as 2006 for defined pension benefit plans and other benefit plans.

IMPACT OF RATE REGULATION

As required by the regulator, the Company is required under its approved cost of service model to defer the amounts of pension benefit expense that exceed or are less than the amounts approved by the regulator to be recovered in rates each year. During the year ended December 31, 2006 the Company has deferred pension expense of $2.7 million (2005 – $0.3 million) that was in excess of the amount approved by the regulator to be refunded in rates in 2007.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

9. STOCK-BASED COMPENSATION

The Company's parent, Terasen Inc., granted stock options to employees of the Company under its stock option plans until November 30, 2005, when all of the outstanding shares of Terasen Inc. were purchased by Kinder Morgan, Inc. In 2005, 164,500 options to purchase shares in Terasen Inc. were issued to employees of the Company at an average exercise price of $29.45. In 2005, the Company was charged, and recorded as an expense, $0.4 million for the fair value of the stock compensation granted in 2005 by Terasen Inc.

10. FINANCING COSTS

	2006	2005
Interest and expense on long-term debt	$ 98.8	$ 102.4
Interest on short-term debt	7.1	9.3
Interest capitalized (note 2)	(0.7)	(0.6)
	$ 105.2	$ 111.1

As allowed by the regulators, during the year ended December 31, 2006, the Company capitalized interest for borrowing requirements for construction of assets that have not been included in rate base of $0.7 million (2005 - $0.6 million).

11. INCOME TAXES

VARIATION IN EFFECTIVE INCOME TAX RATE

Consolidated income taxes vary from the amount that would be computed by applying the federal and provincial combined statutory income tax rate of 34.12% (2005 – 33.97%) to earnings before income taxes as shown in the following table:

	2006	2005
Earnings before income taxes	$ 112.0	$ 104.9
Combined statutory income tax rate	34.12%	33.97%
Combined income taxes at statutory rate	$ 38.2	$ 35.7
Decrease in income taxes resulting from capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	(7.5)	(1.5)
Large Corporations Tax in excess of (surtax credit) surtax	(1.1)	3.7
Deferred Large Corporations Tax	3.1	-
Non-deductible expenses and non-taxable income	2.5	3.6
Provincial income tax applicable to prior years	11.6	-
Other	(3.2)	(1.9)
Actual consolidated income taxes	$ 43.6	$ 39.6
Effective Income Tax Rate	38.93%	37.75%

11. INCOME TAXES (CONTINUED)

FUTURE INCOME TAXES

As a result of the Company accounting for income taxes following the taxes payable method for its regulated operations, the Company has not recognized net future income tax liabilities amounting to $217.5 million at December 31, 2006 (2005 – $230.9 million) and has not recognized a future income tax recovery of $13.4 million for the year ended December 31, 2006 (2005 – expense of $15.1 million), all of which were calculated using the asset and liability method.

12. FINANCIAL INSTRUMENTS

FAIR VALUE ESTIMATES

The carrying values of cash and short-term investments, accounts receivable, short-term notes and accounts payable and accrued liabilities approximate their fair values due to the relatively short period to maturity of the instruments.

The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2006, or by using available quoted market prices, is estimated at $1,547.2 million (2005 - $1,580.7 million). The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

DERIVATIVE INSTRUMENTS

The Company uses derivative instruments to hedge its exposures to fluctuations in natural gas prices, interest rates and foreign currency exchange rates.

Asset (Liability)			**2006**		2005	
December 31 *(in millions)*	Number of swaps and options	Term to maturity (years)	Carrying Value	Fair Value	Carrying Value	Fair Value
Natural Gas						
Commodity Swaps and Options	225	Up to 3	**$ (133.0)**	**$ (133.6)**	$ 21.2	$ 97.9
Interest Swaps	3	Up to 1	-	**(0.9)**	-	(1.6)

The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

12. FINANCIAL INSTRUMENTS (CONTINUED)

Included in the carrying value of the natural gas derivatives is $133.7 million of unrealized fair value losses associated with derivative instruments which were deemed to be ineffective at December 31, 2006 and $0.7 million of derivative instruments which did not qualify for hedge accounting that are in a liability position.

The derivatives entered into by the Company relate to regulated operations and any resulting gains or losses are recorded in rate stabilization accounts, subject to regulatory approval, and passed through to customers in future rates.

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Because it deals with high credit quality institutions in accordance with established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

13. RELATED PARTY TRANSACTIONS

(a) The Company received $4.1 million in 2006 (2005 – $4.1 million) from Terasen Gas (Vancouver Island) Inc. ("TGVI"), a subsidiary company of Terasen Inc., for transporting gas through the Company's pipeline system.

(b) The Company paid approximately $44.6 million during the year ended December 31, 2006 (2005 – $43.6 million) for customer care and billing services to a limited partnership. Terasen Inc. holds a 30% interest in the limited partnership and jointly controls it. The Company is committed to pay approximately $42.6 million as base contract fees for 2007.

(c) The Company paid $8.5 million in 2006 (2005 – $8.7 million) to Terasen Inc. for management services.

(d) The Company charged affiliated companies $6.6 million in 2006 (2005 – $5.6 million) for management services.

14. COMMITMENTS AND CONTINGENCIES

The Company has entered into operating leases for certain building space and natural gas distribution assets. In addition, the Company enters into gas purchase contracts. The following table sets forth the Company's operating lease and gas purchase obligations due in the years indicated:

	Operating leases	Purchase obligations	Total
2007	$ 15.5	$ 474.1	$ 489.6
2008	15.6	22.9	38.5
2009	15.2	27.7	42.9
2010	14.8	-	14.8
2011	14.5	-	14.5
2012 and later	107.6	-	107.6
	$ 183.2	$ 524.7	$ 707.9

14. COMMITMENTS AND CONTINGENCIES (CONTINUED)

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at December 31, 2006.

The Company received a Notice of Assessment dated July 31, 2006 from the British Columbia Social Service Tax authority for $37.1 million of additional provincial sales tax and interest on the Southern Crossing Pipeline, which was completed in 2000. This has not been provided for as the Company will appeal this assessment since management believes that this assessment is without merit and will not have a material adverse impact on our business, financial position, results of operations or cash flows. In October 2006, the Company made a payment of $10 million pending resolution of the appeal as a good faith payment in order to forestall an order from the Province to provide full payment or security. The payment has been recorded as a long term receivable and a request for regulatory deferral account treatment has been made. This payment does not reflect Management's belief as to the ultimate sustainability of the assessment. Subsequent to year end a decision was issued with respect to the appeal filed by Terasen Gas see note 15.

A number of claims and lawsuits seeking damages and other relief are pending against the Company. Management is of the opinion, based upon information presently available, that it is unlikely that any liability, to the extent not provided for through insurance or otherwise, would be material in relation to the Company's consolidated financial statements.

15. SUBSEQUENT EVENTS

On January 1, 2007, the Company and its subsidiary, Squamish, were amalgamated.

On February 26, 2007, Kinder Morgan Inc., the Company's parent announced that it entered into a definitive agreement with Fortis, Inc. to sell Terasen Inc. and its principal natural gas distribution assets, including its subsidiaries Terasen Gas and TGVI as well as other activities including Terasen Energy Services. The sale does not include the petroleum transportation subsidiaries nor investments under the Kinder Morgan Canada name. The purchase price of approximately $3.7 billion includes the assumption of approximately $2.4 billion of debt. The transaction is expected to close in mid-2007 subject to the fulfillment of customary closing conditions and required regulatory approvals.

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform issued a decision in respect of the Company's appeal of an assessment of British Columbia Social Service Tax in the amount of $37.1 million. The Minister has reduced the assessment to $7.0 million including interest. The Social Service Tax Act provides for a further appeal to the courts that must be commenced within 90 days of the Minister's decision. The Company is reviewing its options with respect to the appeal process.

CONSOLIDATED FINANCIAL STATEMENTS OF

TERASEN GAS INC.

YEARS ENDED DECEMBER 31, 2007 AND 2006

MANAGEMENT'S REPORT

Financial Reporting

Management is responsible for the accompanying consolidated financial statements. These financial statements have been prepared in conformity with Canadian generally accepted accounting principles and, where appropriate, include amounts that are based on management's best estimates and judgments.

The Board of Directors, through its Audit Committee, oversees Management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to the Company's Management regarding the preparation and presentation of the consolidated financial statements.

The Company's independent auditors, Ernst and Young, LLP, conducted their audit in accordance with Canadian generally accepted auditing standards. Their report outlines the scope of their audit and gives their opinion on the consolidated financial statements.

Signed:

Signed: R.L. (Randy) Jespersen

President and CEO

Signed:

Signed: Scott A. Thomson

Vice President, Regulatory
Affairs and Chief Financial Officer

Vancouver, Canada
February 1, 2008

AUDITORS' REPORT

To the Shareholder of
Terasen Gas Inc.

We have audited the consolidated balance sheet of **Terasen Gas Inc.** as at December 31, 2007 and the consolidated statements of earnings and comprehensive earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements as at December 31, 2006 and for the year then ended were audited by other auditors who expressed an opinion without reservation on those statements in their report dated March 29, 2007.

Ernst & Young LLP

Vancouver, Canada,
February 1, 2008.

Chartered Accountants

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE EARNINGS

In millions of Canadian dollars *Years ended December 31*	**2007**	2006
Revenues		
Natural gas transmission and distribution	**$ 1,524.6**	$ 1,525.3
Expenses		
Cost of natural gas	**1,017.3**	1,008.7
Operation and maintenance	**169.8**	173.9
Depreciation and amortization	**78.5**	83.9
Property and other taxes	**44.5**	41.6
	1,310.1	1,308.1
Operating income	**214.5**	217.2
Financing costs (note 9)	**106.8**	105.2
Gain on sale of property, plant and equipment	**(8.0)**	-
Earnings before income taxes	**115.7**	112.0
Income tax expense (note 10)	**37.5**	43.6
Net earnings and comprehensive earnings	**$ 78.2**	$ 68.4

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

In millions of Canadian dollars *Years ended December 31*	**2007**	2006
Retained earnings, beginning of year	**$ 72.3**	$ 43.9
Adjustment to retained earnings (note 1(a))	**1.5**	
	73.8	43.9
Net earnings and comprehensive earnings	**78.2**	68.4
	152.0	112.3
Dividends on common shares	**110.9**	40.0
Retained earnings, end of year	**$ 41.1**	$ 72.3

The accompanying notes are an integral part of these consolidated financial statements.

TERASEN GAS INC.

CONSOLIDATED BALANCE SHEETS

In millions of Canadian dollars *Years ended December 31*	**2007**	2006
Assets		
Current assets		
Cash and short-term investments	**$ 5.6**	$ 6.5
Accounts receivable	**310.1**	290.3
Inventories of gas in storage and supplies	**187.4**	168.3
Prepaid expenses	**3.9**	5.2
Current portion of rate stabilization accounts (note 3)	**61.1**	118.1
	568.1	588.4
Property, plant and equipment (note 2)	**2,379.9**	2,352.9
Rate stabilization accounts (note 3)	**11.8**	24.7
Other assets (note 4)	**62.6**	54.4
	$ 3,022.4	$ 3,020.4
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term notes	**$ 305.0**	$ 217.0
Accounts payable and accrued liabilities	**331.2**	407.7
Income and other taxes payable	**38.6**	30.6
Current portion of long-term debt (note 5)	**189.7**	251.4
	864.5	906.7
Long-term debt (note 5)	**1,150.9**	1,090.8
Other long-term liabilities and deferred credits (note 6)	**128.3**	121.0
Future income taxes	**0.5**	0.5
	2,144.2	2,119.0
Shareholders' equity		
Share capital (note 7)	**594.0**	594.0
Contributed surplus (note 7)	**243.1**	235.1
Retained earnings	**41.1**	72.3
	878.2	901.4
	$ 3,022.4	$ 3,020.4

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board:

Signed: *H. Stanley Marshall* Director   Signed: *Harold Calla* Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions of Canadian dollars *Years ended December 31*	**2007**	2006
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$ 78.2**	$ 68.4
Adjustments for non-cash items		
Depreciation and amortization	**78.5**	83.9
Gain on sale of property, plant and equipment	**(8.0)**	-
Other	**(2.5)**	7.9
	146.2	160.2
Changes in working capital	**(28.3)**	83.4
	117.9	243.6
Investing activities		
Property, plant and equipment	**(108.4)**	(108.7)
Other assets and deferred credits	**11.1**	(6.5)
	(97.3)	(115.2)
Financing activities		
Increase (decrease) in short-term notes	**88.0**	(96.0)
Increase in long-term debt	**251.4**	120.0
Reduction of long-term debt	**(250.0)**	(121.5)
Dividends on common shares	**(110.9)**	(40.0)
	(21.5)	(137.5)
Decrease in cash	**(0.9)**	(9.1)
Cash at beginning of year	**6.5**	15.6
Cash at end of year	**$ 5.6**	$ 6.5
Supplemental cash flow information		
Interest paid in the year	**$ 106.0**	$ 106.0
Income taxes paid in the year	**26.6**	14.7
Non-cash transactions		
Mark to market on certain gas derivatives deferred in rate-stabilization accounts	**$ (61.2)**	$ 155.9
Property, plant and equipment purchases included in accounts payable and accrued liabilities	**(0.3)**	-
Net non cash proceeds arising on the sale of property	**8.0**	-

Cash is defined as cash or bank indebtedness.

The accompanying notes are an integral part of these consolidated financial statements.

1. SIGNIFICANT ACCOUNTING POLICIES

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses in the financial statements, as well as the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and reflect the following summary of significant accounting policies.

On February 26, 2007, Knight Inc. (formerly known as Kinder Morgan Inc.), Terasen Inc.'s former parent announced that it had entered into a definitive agreement with Fortis Inc. to sell Terasen Inc. and its principal natural gas transmission and distribution assets, including its subsidiaries Terasen Gas and Terasen Gas (Vancouver Island) Inc. as well as other activities including Terasen Energy Services. The sale did not include the petroleum transportation subsidiaries nor investments under the Kinder Morgan Canada name. The transaction closed on May 17, 2007.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of the Company and its subsidiaries, including Terasen Gas (Squamish) Inc. ("Squamish"). On January 1, 2007, the Company and its subsidiary, Squamish, were amalgamated.

Certain comparative figures have been reclassified to conform with the current year's presentation.

CHANGES IN ACCOUNTING POLICIES

ACCOUNTING CHANGES

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (CICA) revised Handbook Section 1506, *Accounting Changes,* relating to changes in accounting policies, changes in accounting estimates and errors.

Under revised Section 1506, voluntary changes in accounting policies are made only if they result in the financial statements providing reliable and more relevant information. Additional disclosure is required when the Company has not applied a new primary source of Canadian GAAP that has been issued but is not yet effective, as well as when changes in accounting estimates and errors occur. Adoption of this revised standard had no material impact on the Company's consolidated financial statements for the year ended December 31, 2007.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

FINANCIAL INSTRUMENTS

The Company utilizes derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices.

Effective January 1, 2007, the Company adopted the following new accounting standards issued by the CICA.

a) Section 3855, *Financial Instruments – Recognition and Measurement*, prescribes the criteria for recognition and presentation of financial instruments on the balance sheet and the measurement of financial instruments according to prescribed classifications. This section also addresses how financial instruments are measured subsequent to initial recognition and how the gains and losses are recognized.

   The Company is required to designate its financial instruments into one of the following five categories: held for trading; available for sale; held to maturity; loans and receivables; and other financial liabilities. All financial instruments are to be initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value with any change in fair value recorded in net earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

   All derivative financial instruments are recorded on the balance sheet at fair value. Mark-to-market adjustments on these instruments are included in net earnings, unless the instruments are designated as part of a cash flow hedge relationship, and then the effective portion of changes in fair value are recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in net earnings. For regulated financial instruments, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates, is subject to regulatory deferral treatment to be recovered from or refunded to customers in future rates.

   In accordance with the standard's transitional provisions, the Company recognizes as separate assets and liabilities only embedded derivatives acquired or substantively modified on or after January 1, 2003.

   The Company has designated its financial instruments as follows:

   - Cash and short-term investments are classified as "*Held for Trading*" and are recorded at fair value. Due to the relatively short period to maturity of these financial instruments the carrying values approximate their fair values.
   - Accounts receivable and long-term receivables and investments are classified as *"Loans and Receivables"*. These financial assets are recorded at values that approximate their amortized cost using the effective interest method.
   - Short-term notes, accounts payable and accrued liabilities, long-term debt, and related issue costs are classified as "*Other Financial Liabilities*". These financial liabilities are recorded at values that approximate their amortized cost using the effective interest method.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

As a result of adopting Section 3855, deferred financing costs of $10.8 million as at December 31, 2007 (2006 - $7.8 million), relating to long-term debt, have been reclassified from other assets to long-term debt on the balance sheet. These costs will be taken into earnings using the effective interest method over the life of the related debt. Prior to January 1, 2007, deferred financing costs were amortized using the straight-line method of amortization. As allowed by the standard a one-time adjustment of $1.5 million has been made to retained earnings to reflect the difference between the straight-line method and the effective interest method of amortization prior to January 1, 2007.

The Company recognizes transaction costs associated with financial assets and liabilities, that are classified as other than held for trading, as an adjustment to the cost of those financial assets and liabilities recorded on the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument.

b) Section 1530, *Comprehensive Income*, requires the presentation of a statement of comprehensive income and provides guidance for the reporting and display of other comprehensive income. Comprehensive income represents the change in equity of an enterprise during a period from transactions and other events arising from non-owner sources including gains and losses arising on translation of self-sustaining foreign operations, gains and losses from changes in fair value of available for sale financial assets and changes in fair value of the effective portion of cash flow hedging instruments. The Company has not recognized any adjustments through other comprehensive income for the year ended December 31, 2007 and did not identify any components of comprehensive income on adoption of this standard.

c) Section 3865, *Hedges,* specifies the criteria under which hedge accounting may be applied, how hedge accounting should be performed under permitted hedging strategies and the required disclosures. The majority of the Company's cash flow hedges are for the purchase of natural gas. Given that the Company is subject to rate regulation, the ineffective portion of changes in the fair value of these hedges is deferred as an asset or liability until it is settled, offset by an asset or liability on behalf of customers. Upon settlement, the recognized gain or loss is recorded as a regulatory asset or liability and is collected from or refunded to ratepayers in subsequent periods. The Company recognized an additional liability of $1.1 million to counterparties for unrealized losses related to gas purchase hedges at January 1, 2007 and an amount recoverable from ratepayers of $1.1 million. Amounts recoverable from ratepayers are recorded in rate stabilization accounts.

The Company utilizes cash flow hedges to hedge the variability in interest payments on the underlying debt instruments. Cash flow hedges for rate regulated businesses are recorded in Other assets with the offset to Other long- term liabilities and deferred credits. The adoption of this new standard on January 1, 2007 increased Other assets by $0.8 million and increased Other long-term liabilities and deferred credits by $0.8 million.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

REGULATION

The Company is subject to the regulation of the British Columbia Utilities Commission ("the BCUC"), an independent regulatory authority. The Company has a multi-year agreement that expired at the end of 2007. On March 22, 2007, the BCUC approved the Company's application for a two-year extension to the current multi-year agreement extending the existing term until the end of 2009. This multi-year agreement is a cost-of-service based agreement with allowed rates of return on approved rate base set by the BCUC. For 2007, the allowed ROE was set at 8.37%. The allowed rate of return is based on a notional debt-equity ratio of 65% debt and 35% equity. The Company has an annual review process for rate approvals and allowed rates of return are reset annually, unless directed differently by the BCUC. For 2008, the allowed ROE has been set at 8.62%.

The BCUC exercises statutory authority over such matters as rates of return, construction and operation of facilities, accounting practices, rates, and contractual agreements with customers. Rates are bundled to include transmission and distribution services, where applicable.

In order to recognize the economic effects of regulation, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non-regulated businesses.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, GAAP would not permit the recognition of regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in other assets whereas current regulatory assets are recorded in accounts receivable. Regulatory liabilities are recorded in other long-term liabilities and deferred credits.

The impacts of rate regulation on the Company's operations for the twelve months ending December 31, 2007 and as at December 31, 2007 are described in the Significant Accounting Policies, and in Note 2 "Property, Plant and Equipment", Note 3 "Rate Stabilization Accounts", Note 4 "Other Assets", Note 6 "Other Long-Term Liabilities and Deferred Credits", Note 8 "Employee Benefit Plans", Note 9 "Financing Costs", and Note 10 "Income Taxes".

INVENTORIES

Inventories of gas in storage are valued at weighted-average cost. The cost of gas in storage is recovered from customers in future rates. Supplies and other inventories are valued at the lower of cost and net realizable value.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures for system expansions, betterments and replacements, an allocation of overhead costs and an allowance for funds used during construction. When allowed by the BCUC, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

Depreciation of regulated assets is recorded on a straight-line basis over their useful lives. Depreciation rates for regulated assets are approved by the respective regulator.

The cost of regulated depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation, as is any gain or loss incurred on disposal.

IMPAIRMENT OF LONG-LIVED ASSETS

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. There was no impairment of long-lived assets for the year ended December 31, 2007.

ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Company concurrently recognizes a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset. The fair value of the asset retirement obligation is estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

Changes in the obligation due to the passage of time are recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Company's natural gas transmission and distribution systems are not currently determinable, the Company has not recognized an asset retirement obligation at December 31, 2007 and 2006. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

RATE STABILIZATION ACCOUNTS

The Company is authorized by the BCUC to maintain rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility. The Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual versus forecast use for residential and commercial customers.

The Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The two accounts segregate costs that are allocable to all sales customers (MCRA) and all residential customers and certain commercial and industrial customers for whom Terasen Gas acquires gas supply (CCRA).

All rate stabilization account balances are recovered through rates as approved by the BCUC.

DEFERRED CHARGES

The Company defers certain charges which the regulatory authorities or contractual arrangements require or permit to be recovered through future rates. Deferred charges are amortized over various periods as approved by the BCUC and depending on the nature of the charges.

Deferred charges not subject to regulation relate to projects which are expected to benefit future periods and will be capitalized on completion, expensed on project abandonment, or amortized over their useful lives.

REVENUE RECOGNITION

The Company recognizes revenues when products have been delivered or services have been performed.

Revenues from natural gas sales are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year and are adjusted for the RSAM and other BCUC approved orders.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

POST-EMPLOYMENT BENEFIT PLANS

The Company sponsors a number of employee benefits plans. These plans include both defined benefit and defined contribution pension plans, and various other post-retirement benefit plans.

The cost of pensions and other post-retirement benefits earned by employees is actuarially determined as the employee provides service. The Company uses the projected benefit method based on years of service and estimates of expected returns on plan assets, salary escalation, retirement age of employees, mortality and expected future health-care costs. The discount rate used to value liabilities is based on AA Corporate bond yields. The Company accrues the cost of defined benefit pensions and post-employment benefits as the employee provides services, except when the BCUC requires costs to be expensed as paid.

The expected return on plan assets is based on management’s estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets as of December 31, 2007 is calculated as the average of the market value of invested assets at December 31, 2007 and two actuarially determined extrapolated market values of invested assets at December 31, 2007. The two extrapolated market values are calculated by using the market value of invested assets at December 31, 2005 rolled forward to December 31, 2007 using 2006 and 2007 net contributions and assumed investment returns, and the market value of invested assets at December 31, 2006 rolled forward to December 31, 2007 using 2007 net contributions and assumed investment returns. These three amounts are then averaged and reported as the market-related value of plan assets.

Adjustments, in excess of 10% of the greater of the accrued benefit obligation and plan asset value, that result from plan amendments, changes in assumptions and experience gains and losses, are amortized over the expected average remaining service life of the employee group covered by the plan. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

Defined contribution plan costs are expensed by the Company as contributions are payable.

INCOME TAXES

The Company accounts for and recover income tax expense in rates as prescribed by the BCUC for ratemaking purposes. This includes accounting for income taxes by the taxes payable method and accounting for certain deferral and rate stabilization accounts on a net of realized tax basis, as approved by the BCUC. Therefore, future income taxes related to temporary differences are not recorded. The taxes payable method is followed as there is reasonable expectation that all future income taxes will be recovered in rates when they become payable.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

VARIABLE INTEREST ENTITIES

The Company has performed a review of the entities with whom it conducts business and has concluded that there are no entities that are required to be consolidated or variable interests that are required to be disclosed under the requirements of the Guideline.

FUTURE ACCOUNTING PRONOUNCEMENTS

a) *International Financial Reporting Standards ("IFRS"):* In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five year transitional period. By no later than March 31, 2008, the AcSB is expected to issue a report confirming or revising the expected transition date of January 1, 2011 for the conversion to IFRS. The proposed transition date of January 1, 2011 will require the restatement for comparative purposes of amounts reported by the Company for the year ended December 31, 2010. While the Company has begun assessing the adoption of IFRS for 2011, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

b) *Rate-Regulated Operations:* In March 2007, the AcSB issued an Exposure Draft on rate-regulated operations that proposed: (i) the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, of the CICA Handbook providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation be removed; (ii) the explicit guidance for rate-regulated operations provided in Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxe*s, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*, be removed; and (iii) Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation*, be retained as is. The AcSB has also observed that relying on US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* ("FAS 71"), as another source of Canadian GAAP in the absence of CICA Handbook guidance addressing the specific circumstances of entities subject to rate regulation, is consistent with Section 1100 when the qualifying criteria of FAS 71 are met.

In August 2007, the AcSB issued a Decision Summary on the Exposure Draft that supported the removal of the temporary exemption in Section 1100, *General Accepted Accounting Principles*, and the amendment to Section 3465, *Income Taxes,* to recognize future income tax liabilities and assets as well as an offsetting regulatory asset or liabilities for entities subject to rate regulation. Both changes will apply prospectively for fiscal years beginning on or after January 1, 2009. It was also decided that the current guidance pertaining to property, plant and equipment and disposal of long-lived assets and discontinued operations and consolidated financial statements be maintained and that the existing AcG-19 will not be withdrawn from the Handbook but that the guidance will be updated as a result of the other changes. The AcSB also decided that the final Background Information and Basis for Conclusions associated with its rate regulation project would not express any views of the AcSB regarding the status of US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, as an "other source of GAAP" within the Canadian GAAP hierarchy.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Effective January 1, 2009, the impact on the Company of the amendment to Section 3465, *Income Taxes,* will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to or recovered from customers in future gas rates. Currently, the Company uses the taxes payable method of accounting for income taxes on regulated earnings. The estimated effect on the Company's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2007, would have been an increase in future tax assets of $16.1 million and an increase in future tax liabilities of $262.3 million, including that associated with income taxes that will become payable on future revenues as they are collected from customers when the tax timing differences reverse. There would also be a corresponding increase in regulatory liabilities of $16.1 million and an increase in regulatory assets of $262.3 million. The Company is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate regulated operations.

c) *Inventories:* In March 2007, the AcSB approved a new standard with respect to inventories effective for fiscal years beginning on or after January 1, 2008. The new standard requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in first-out inventory costing methodology; and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This new standard is not expected to have a material impact on the Company's earnings.

d) *Capital Disclosures:* As a result of new Section 1535, *Capital Disclosures,* the Company will be required to include additional information in the notes to the financial statements about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding an entity's objectives, policies and processes for managing capital. This Section is applicable for the fiscal year beginning on January 1, 2008.

e) *Disclosure and Presentation of Financial Instruments:* New accounting recommendations for disclosure and presentation of financial instruments are effective for the Company beginning January 1, 2008. The new recommendations require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

2. PROPERTY, PLANT AND EQUIPMENT

2007

	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas transmission and distribution systems	**2.34%**	**$ 2,769.6**	**$ 634.3**	**$ 2,135.3**
Plant, buildings and equipment	**7.41%**	**256.3**	**92.6**	**163.7**
Land and land rights	**0.00%**	**82.3**	**1.4**	**80.9**
		$ 3,108.2	**$ 728.3**	**$ 2,379.9**

2006

	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas transmission and distribution systems	2.33%	$ 2,687.9	$ 576.5	$ 2,111.4
Plant, buildings and equipment	8.25%	304.5	145.3	159.2
Land and land rights	0.00%	83.6	1.3	82.3
		$ 3,076.0	$ 723.1	$ 2,352.9

As allowed by the regulators, during the year ended December 31, 2007 the Company capitalized an allowance for equity funds during construction at approved rates of $0.8 million (2006 - $0.7 million) and approved capitalized overhead of $27.5 million (2006 - $27.2 million), with offsetting inclusions in earnings.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

3. RATE STABILIZATION ACCOUNTS

	2007	2006
Current Assets		
RSAM	**$ 5.9**	$ 11.3
CCRA	**34.8**	81.3
MCRA	**20.4**	25.5
	61.1	118.1
Long-Term Assets		
RSAM	**11.8**	24.7
	11.8	24.7
Net rate stabilization accounts	**$ 72.9**	$ 142.8

The current portion of the rate stabilization accounts represents the amounts expected to be recovered or refunded in rates over the next year. Actual recoveries/(refunds) will vary depending on natural gas consumption and recovery amounts approved by the BCUC. Rate stabilization accounts are presented net of tax, where applicable.

The RSAM account is anticipated to be recovered in rates over three years. Recovery of the RSAM balance is dependent upon annually approved rates and actual gas consumption volumes. The MCRA and CCRA accounts are anticipated to be fully recovered or paid within the next fiscal year.

In the absence of rate regulation, the costs in the rate stabilization accounts above would have been expensed as incurred which would have resulted in increased natural gas transmission and distribution revenues of $568.6 million (2006 – $639.7 million), increased cost of natural gas of $494.6 million (2006 - $789.8 million) and increased income tax expense of $4.1 million (2006 – $1.7 million).

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

4. OTHER ASSETS

	2007	2006
Deferred charges		
Subject to rate regulation and approved for recovery in rates		
Income taxes recoverable on post-employment benefits	**$ 15.5**	$ 13.1
Residential unbundling costs	**8.6**	0.8
Replacement transportation agreement	**1.3**	2.2
Commercial commodity unbundling costs	**1.2**	2.5
Other items approved for recovery in rates	**6.1**	7.7
Subject to rate regulation but not yet approved for recovery in rates		
Southern Crossing Pipeline PST Reassessment	**7.2**	10.0
	39.9	36.3
Long-term receivables	**9.2**	9.6
Pension assets (Note 8)	**13.5**	8.5
	$ 62.6	$ 54.4

Amortization of these deferred charges in rates for the year ended December 31, 2007 totalled $2.6 million (2006 - $2.3 million).

The deferral account for income taxes on post-employment benefits relates to income tax amounts on post employment benefit expense. The BCUC allows post-employment benefits to be collected from customers through rates calculated on the accrual basis, rather than a cash paid basis, which produces a timing difference for income tax purposes. Since the Company accounts for income taxes using the taxes payable basis of accounting, the tax effect of this timing difference is included in other assets, and will be reduced as cash payments for post-employment benefits exceed required accruals and amounts collected from customers in rates.

The residential and commercial commodity unbundling costs deferred are costs incurred to develop a third-party marketer alternative for residential and commercial customers to purchase natural gas from suppliers other than the Company. The BCUC has approved the recovery of these costs in rates over a three-year period. For commercial commodity unbundling, two years remain at December 31, 2007. Residential commodity unbundling costs will be recovered commencing in 2008.

The deferral account for the replacement transportation agreement relates to amounts that the Company is allowed to recover from customers in rates in order to cover any shortfall in revenues relative to a minimum amount approved by the BCUC on the Company's Southern Crossing Pipeline. The deferral account is being amortized and recovered in rates over a five-year period, of which two years remain at December 31, 2007.

4. OTHER ASSETS (CONTINUED)

The deferral account for the Southern Crossing Pipeline PST reassessment relates to a payment made in regards to a possible assessment of additional provincial sales tax on the Southern Crossing Pipeline. See Note 13. In 2006, the Company made a payment of $10 million pending resolution of the appeal as a good faith payment in order to forestall an order from the Province of British Columbia (the "Province") to provide full payment or security. During 2007, the assessment was reduced to $7 million and the overpayment was refunded to the Company. Depending on the success of the appeal, the Company will either be refunded this payment from the Province or alternatively expects to recover the costs from customers in future rates.

Deferred charges and deferred credits for rate regulated entities that have been aggregated in the table above and in Note 6 relate to more than 40 deferral accounts, none of which exceed $1.7 million individually. All of these accounts have been approved by regulators in prior annual rate approvals or orders and are being amortized over various periods depending on the nature of the costs.

In the absence of rate regulation, the deferred charges in the above table would have been recorded in income, except for the costs related to the pension asset and the Southern Crossing Pipeline PST Reassessment. This would have resulted in increased natural gas transmission and distribution revenues of $2.1 million (2006 - $2.1 million), increased operation and maintenance costs $12.9 million (2006 - $2.1 million), decreased depreciation and amortization of $2.6 million (2006 - $2.3 million), increased financing costs of $0.6 million (2006 - $1.0 million), and decreased income tax expense of $1.3 million (2006 – increased $2.3 million)

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

5. LONG-TERM DEBT

	2007	2006
(a) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2015	**$ 74.9**	$ 74.9
10.30% Series B, due September 30, 2016	**200.0**	200.0
(b) Debentures and Medium Term Note Debentures:		
10.75% Series E, due June 8, 2009	**59.9**	59.9
6.20% Series 9, due June 2, 2008	**188.0**	188.0
6.95% Series 11, due September 21, 2029	**150.0**	150.0
6.50% Series 13, due October 16, 2007	**-**	100.0
6.50% Series 18, due May 1, 2034	**150.0**	150.0
5.90% Series 19, due February 26, 2035	**150.0**	150.0
Floating rate, Series 20, interest rate 2006 - 4.25% due October 24, 2007	**-**	150.0
5.55% Series 21, due September 25, 2036	**120.0**	120.0
6.00% Series 22, due October 2, 2037	**250.0**	-
Obligations under capital leases, at 6.88% (2006 – 5.62%)	**8.6**	7.2
Total long-term debt	**1,351.4**	1,350.0
Less: current portion of long-term debt	**189.7**	251.4
Less: long term debt issue costs	**10.8**	7.8
	$ 1,150.9	$ 1,090.8

(a) PURCHASE MONEY MORTGAGES:

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Company's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

(b) DEBENTURES AND MEDIUM TERM NOTE DEBENTURES:

The Company's debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

On October 2, 2007, Terasen Gas issued $250.0 million of Medium Term Note Debentures at a coupon interest rate of 6.00%. The debentures mature on October 2, 2037 and are unsecured and subject to restrictions of the Trust Indenture. The proceeds were used to repay Terasen Gas' Series 13 and Series 20 Medium Term Debentures which matured in 2007.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

5. LONG-TERM DEBT (CONTINUED)

Long-term debt issue costs are amortized using the effective interest rate method as discussed in Note 1.

The Company's Series B Purchase Money Mortgages, Series E Debentures, and Series 11, Series 18, Series 19, Series 21, and Series 22 Medium Term Note Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Required principal repayments over the next five years and thereafter are as follows:

2008	$ 189.7
2009	61.6
2010	1.7
2011	1.7
2012	1.7
Thereafter	1,095.0

6. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS

	2007	2006
Pension and other post-employment benefit liabilities (Note 8)	**$ 47.6**	$ 39.2
Deferred gains on sale of natural gas transmission and distribution assets	**50.5**	54.8
Deferred credits		
Subject to rate regulation and approved for recovery in rates		
Earnings Sharing Mechanism	**12.5**	12.6
SCP Net Mitigation Revenue	**4.4**	3.8
Pension cost variance	**2.3**	1.5
Large Corporation Tax Elimination	**2.1**	3.1
Customer share of land sale	**1.7**	-
	$128.3	$121.0

The deferred gains on sale of natural gas transmission and distribution assets occurred upon the sale of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $70.5 million on combined cash proceeds of $141.1 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 13.

Amortization of these deferred credits in rates for the year ended December 31, 2007 totalled $5.4 million (2006 - $4.1 million).

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

6. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS (CONTINUED)

The Earnings Sharing Mechanism is a mechanism agreed to in the Company's multi-year agreement to share, on a 50/50 basis, amounts earned by the Company on its regulated activities that exceed or are less than amounts allowed by the BCUC in the cost-of-service allowed return calculations. These amounts are shared on an after-tax basis, and are returned to customers in rates.

The SCP Net Mitigation Revenue is revenue that is received from third parties for the use of the SCP transportation capacity that has not been utilized by the firm transportation agreement customers. This account is used to record differences between actual revenues from SCP mitigation and what has been approved in the current revenue requirement. Amounts are being amortized to income over 5 years.

The pension cost variance account accumulates differences between pension expense that is approved for recovery in rates and actuarial pension expense. Amounts are amortized to income in the following year.

The large corporation tax elimination costs resulted from the federal government eliminating the tax on large corporations in 2006. The BCUC allows large corporation tax to be recovered from customers through rates. These costs were collected from customers through rates in 2006 and now are owed back to customers in future rates upon the elimination of the large corporation tax. The costs are being returned to customers in rates over a three year period beginning January 1, 2007.

The customer share of land sale represents the customers' portion of the net of tax gain on the sale of surplus land that will be refunded to customers in 2008.

In the absence of rate regulation, the other long-term liabilities and deferred credits in the above table would have been recorded in income, aside for the pension and other post-employment benefit liabilities and the deferred gains on sale of natural gas transmission and distribution assets. This would have resulted in increased natural gas transmission and distribution revenues of $6.2 million (2006 - $10.2 million), increased cost of natural gas of $0.4 million (2006 – decreased $0.6 million), decreased operation and maintenance costs of $2.3 million (2006 – $2.5 million), decreased property and other taxes of $1.1 million (2006 - $0.9 million), increased depreciation and amortization of $5.4 million (2006 - $4.1 million), decreased financing costs of $0.4 million (2006 – $1.2 million) and increased income tax expense of $1.8 million (2006 – $2.0 million).

7. SHARE CAPITAL AND CONTRIBUTED SURPLUS

The Company is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

	2007	2006
Common shares, 59,591,732 shares issued	**$ 594.0**	$ 594.0

7. SHARE CAPITAL (CONTINUED)

CONTRIBUTED SURPLUS

Income tax benefits in the amount of $8.0 million (2005 - $27.3 million) relating to transactions with entities under common control were recorded as a credit to contributed surplus in 2007.

DIVIDEND POLICY

As part of its approval of the acquisition of Terasen Inc. by Knight, Inc., and subsequently of Terasen Inc. by Fortis Inc. from Knight Inc., the BCUC imposed a number of conditions intended to ring-fence the Company from its parent companies. These restrictions included a prohibition on the payment of dividends unless the Company has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. The Company must maintain a percentage of common equity to total capital that is at least as much as that determined by the BCUC from time to time for ratemaking purposes. Dividends from the Company will not be allowed by the regulator if the requisite equity is not in place. The Company's dividend policy is intended to ensure that it maintains at least as much common equity as that deemed by the BCUC for rate-making purposes.

8. EMPLOYEE BENEFIT PLANS

The Company is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. The Company also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan:

DEFINED BENEFIT PLANS

Retirement benefits under the defined benefit plans are based on employees' years of credited service and remuneration. Company contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were at December 31, 2004 and December 31, 2005 and the dates of the next required valuations are December 31, 2007 and December 31, 2008. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 10.1 years (2006 – 10.2 years).

Effective January 1, 2007 all employees became participants in a new defined benefit pension plan in which costs are split evenly between the employees and employer. All current employees were grandfathered in their respective defined contribution and defined benefit plans and those plans were closed to all new members, except for the TGVI plans which were closed to all new non-unionized members. The most recent actuarial valuation of the new defined benefit pension plan for funding purposes was May 17, 2007 and the date of the next required valuation is December 31, 2009.

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

DEFINED CONTRIBUTION PLAN

Effective in 2000, all new non-union employees became members of defined contribution pension plans. Company contributions to the plan are based upon employee age and pensionable earnings. Effective January 1, 2007, this plan was closed and all new employees became participants in the new defined benefit plan described above.

SUPPLEMENTAL PLANS

Certain employees are eligible to receive supplemental benefits under both the defined benefit and defined contribution plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and are secured by letters of credit.

OTHER POST-EMPLOYMENT BENEFITS

The Company provides retired employees with other post-employment benefits that include, depending on circumstances, supplemental health, and life insurance coverage. Post-employment benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health care cost escalation. The most recent actuarial valuations were completed as at December 31, 2005 and the date of the next required valuation is December 31, 2008. The expected weighted average remaining service life of employees covered by these benefit plans is 9.0 years (2006 - 9.0 years).

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 each year. The financial positions of the employee defined benefit pension plans and other benefit plans are presented in aggregate in the tables below:

	Defined benefit pension plans		Other benefit plans	
	2007	2006	**2007**	2006
Plan assets				
Fair value, beginning of year	**$ 228.9**	$ 202.4	**$ -**	$ -
Actual return on plan assets	**8.1**	28.6	**-**	-
Company contributions	**5.8**	5.3	**1.2**	1.2
Contributions by members	**4.1**	3.0	**-**	-
Benefits and settlements paid	**(9.5)**	(10.3)	**(1.1)**	(1.1)
Other	**-**	(0.1)	**(0.1)**	(0.1)
Fair value, end of year	**237.4**	228.9	**-**	-
Accrued benefit obligation				
Obligation, beginning of year	**227.3**	213.7	**68.2**	64.3
Current service cost	**6.6**	5.3	**1.3**	1.2
Interest cost	**11.5**	10.7	**3.4**	3.3
Contributions by members	**4.1**	3.0	**-**	-
Benefits and settlements paid	**(9.5)**	(10.3)	**(1.1)**	(1.1)
Actuarial losses (gains)	**(4.0)**	4.9	**(3.1)**	0.7
Change in discount rate	**-**	-	**-**	-
Past service cost and other	**-**	-	**-**	(0.2)
Balance, end of year	**236.0**	227.3	**68.7**	68.2
Funded status - plan surplus (deficiency)	**1.4**	1.6	**(68.7)**	(68.2)
Unamortized transitional (benefit) obligation	**(8.7)**	(10.5)	**1.5**	3.1
Unamortized actuarial loss	**16.2**	13.3	**22.3**	27.7
Unamortized past service costs	**2.7**	3.2	**(0.8)**	(0.9)
Accrued benefit asset (liability)	**$ 11.6**	$ 7.6	**$ (45.7)**	$ (38.3)
Represented by				
Pension assets	**$ 13.5**	$ 8.5	**$ -**	$ -
Accrued benefit liability	**(1.9)**	(0.9)	**(45.7)**	(38.3)
	$ 11.6	$ 7.6	**$ (45.7)**	$ (38.3)

The net accrued benefit liability is included in other long-term liabilities and deferred credits (Note 6) and the pension asset is included in other assets (Note 4).

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

Included in the accrued benefit obligation and fair value of the plan assets at year-end are the following amounts in respect of plans with accrued benefit obligations in excess of fair value of assets:

	Pension benefit plans		Other benefit plans	
	2007	2006	**2007**	2006
Accrued benefit obligations:				
Unfunded plans	**$ 12.8**	$ 10.2	**$ 68.7**	$ 68.2
Funded plans	**170.4**	162.2	**-**	-
	183.2	172.4	**68.7**	68.2
Fair value of plan assets	**183.1**	173.0	**-**	-
Funded status surplus (deficit)	**$ (0.1)**	$ 0.6	**$ (68.7)**	$ (68.2)

The accrued benefit obligations for unfunded pension benefit plans are secured by letters of credit.

The net benefit plan expense is as follows:

	Pension benefit plans		Other benefit plans	
	2007	2006	**2007**	2006
Current service cost	**$ 6.6**	$ 5.3	**$ 1.3**	$ 1.2
Interest cost on projected benefit obligations	**11.5**	10.7	**3.4**	3.3
Actual positive return on plan assets	**(8.1)**	(28.6)	**-**	-
Net actuarial losses (gains)	**(4.0)**	4.9	**(3.1)**	0.7
Past service costs	**-**	-	**-**	(0.2)
Other	**-**	0.1	**0.1**	0.1
Net benefit plan (income) expense before adjustments	**6.0**	(7.6)	**1.7**	5.1
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return on plan assets	**(7.6)**	14.8	**-**	-
Difference between actual and recognized actuarial losses in year	**4.7**	(3.4)	**5.4**	1.8
Difference between actual and recognized past service costs in year	**0.5**	0.5	**(0.1)**	-
Amortization of transitional (benefit) obligation	**(1.8)**	(1.8)	**1.6**	1.6
Other	**-**	-	**-**	-
Net benefit plan expense	**$ 1.8**	$ 2.5	**$ 8.6**	$ 8.5
Defined contribution plan expense	**$ -**	$ 1.1		
	$ 1.8	$ 3.6		

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

BENEFIT PLAN ASSETS

The weighted-average asset allocation by asset category of the Company's defined benefit pension plans and other funded benefit plans is as follows:

	Defined Benefit Pension Plans	
	2007	2006
Equity securities	**56%**	58%
Fixed income securities	**35%**	34%
Other assets	**9%**	8%
Total assets	**100%**	100%

The investment policy for benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Company's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost-effective manner while not compromising the security of the respective plans. The pension plans utilize external investment managers to manage the investment policy. Assets in the plan are held in trust by independent third parties.

The pension plans do not directly hold any shares of the Company's parent.

SIGNIFICANT ASSUMPTIONS

The discount rate assumption used in determining pension and post-retirement benefit obligations and net benefit expense reflects the market yields, as of the measurement date, on high-quality debt instruments. The expected rate of return on plan assets assumption is reviewed annually by management, in conjunction with actuaries. The assumption is based on the expected returns for the various asset classes, weighted by the portfolio allocation.

The weighted average significant actuarial assumptions used to determine the accrued benefit obligation and the benefit plan expense are as follows:

	Pension benefit plans		Other benefit plans	
	2007	2006	**2007**	2006
Accrued benefit obligation				
Discount rate at December 31, based on AA Corporate bonds	**5.25%**	5.00%	**5.25%**	5.00%
Rate of compensation increase for five years and 3.36% thereafter	**3.63%**	3.64%	**-**	-
Net benefit plan expense				
Discount rate at January 1, based on AA Corporate bonds	**5.00%**	5.00%	**5.00%**	5.00%
Expected rate of return on plan assets	**7.25%**	7.25%	**-**	-

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

The assumed health-care cost trend rates for other post-employment benefit plans are as follows:

	2007	2006
Extended health benefits		
Initial health care cost trend rate	**8.0%**	10.0%
Annual rate of decline in trend rate	**1.0%**	1.0%
Ultimate health care cost trend rate	**5.0%**	5.0%
Year that the rate reaches the ultimate trend rate	**2011**	2011
Medical Services Plan Benefits Premium trend rate	**4.0%**	4.0%

A one percentage-point change in assumed health-care cost trend rates would have the following effects:

2007	One percentage-point increase	One percentage-point decrease
Effect on the total of the service costs and interest cost components of the benefit plan expense	**$ 0.6**	**$ (0.5)**
Effect on accrued benefit obligation	**8.2**	**(7.8)**

CASH FLOWS

Total cash contributions for employee benefit plans consist of:

	Employee benefit plans	
	2007	2006
Funded plans	**$ 5.0**	$ 4.5
Beneficiaries of unfunded plans	**2.0**	2.0
Defined contribution plans	**-**	1.1
Total	**$ 7.0**	$ 7.6

The contributions for 2008 are anticipated to be approximately the same as 2007 for defined pension benefit plans and other benefit plans.

IMPACT OF RATE REGULATION

As required by the regulator, the Company is required under its approved cost of service model to defer the amounts of pension benefit expense that exceed or are less than the amounts approved by the regulator to be recovered in rates each year. During the year ended December 31, 2007 the Company has deferred pension expense of $1.5 million (2006 - $2.3 million) that was less than the amount approved by the regulator to be refunded in rates in 2008.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

9. FINANCING COSTS

	2007	2006
Interest and expense on long-term debt	**$ 101.1**	$ 98.8
Interest on short-term debt	**6.5**	7.1
Interest capitalized (note 2)	**(0.8)**	(0.7)
	$ 106.8	$ 105.2

As allowed by the regulator, during the year ended December 31, 2007, the Company capitalized interest for borrowing requirements for construction of assets that have not been included in rate base of $0.8 million (2006 - $0.7 million).

10. INCOME TAXES

VARIATION IN EFFECTIVE INCOME TAX RATE

Consolidated income taxes vary from the amount that would be computed by applying the federal and provincial combined statutory income tax rate of 34.12% (2006 – 34.12%) to earnings before income taxes as shown in the following table:

	2007	2006
Earnings before income taxes	**$ 115.7**	$ 112.0
Combined statutory income tax rate	**34.12%**	34.12%
Combined income taxes at statutory rate	**$ 39.4**	$ 38.2
Decrease in income taxes resulting from capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	**(4.5)**	(7.5)
Large Corporation Tax in excess of (surtax credit) surtax	**-**	(1.1)
Large Corporation Tax deferred for regulatory purposes	**-**	3.1
Non-deductible expenses and non-taxable income	**(2.5)**	2.5
Provincial income tax applicable to prior years	**1.4**	11.6
Other	**3.7**	(3.2)
Actual consolidated income taxes	**$ 37.5**	$ 43.6
Effective Income Tax Rate	**32.41%**	38.93%

10. INCOME TAXES (CONTINUED)

FUTURE INCOME TAXES

As a result of the Company accounting for income taxes following the taxes payable method for its regulated operations, the Company has not recognized net future income tax liabilities amounting to $196.5 million at December 31, 2007 (2006 – $217.5 million) and has not recognized a future income tax recovery of $21.0 million for the year ended December 31, 2007 (2006 – $13.4 million), all of which were calculated using the asset and liability method.

11. FINANCIAL INSTRUMENTS

FAIR VALUE ESTIMATES

	December 31, 2007		December 31, 2006	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and short-term investments [1]	**$ 5.6**	**$ 5.6**	$ 6.5	$ 6.5
Loans and receivables				
Accounts receivable [2]	**310.1**	**310.1**	290.3	290.3
Other financial liabilities				
Short-term notes [2]	**305.0**	**305.0**	217.0	217.0
Accounts payable and accrued liabilities [2]	**331.2**	**331.2**	407.7	407.7
Long-term debt, including current portion [3,4,5]	**1,340.6**	**1,550.3**	1,342.2	1,547.2

[1] Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.
[2] Carrying value approximates amortized cost
[3] Carrying value is measured at amortized cost using the effective interest rate method
[4] Carrying value at December 31, 2007 is net of unamortized deferred financing costs of $10.8 million. On January 1, 2007, deferred financing costs were reclassified from other assets in accordance with the transitional provisions of Section 3855. The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.
[5] Fair value is calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2007, or by using available quoted market prices.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

Effective interest expense associated with the Company's short-term borrowings and long-term debt is disclosed in Note 9 to these consolidated financial statements.

11. FINANCIAL INSTRUMENTS (CONTINUED)

DERIVATIVE INSTRUMENTS

The Company uses derivative instruments to hedge its exposures to fluctuations in natural gas prices and interest rates.

Asset (Liability)			**2007**		2006	
December 31 *(in millions)*	Number of swaps and options	Term to maturity (years)	Carrying Value	Fair Value	Carrying Value	Fair Value
Natural Gas						
Commodity Swaps and Options	202	Up to 3	**$ (77.3)**	**$ (77.3)**	$ (133.0)	$ (133.6)
Interest Swaps	-	-	-	**-**	-	(0.9)

The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

The derivatives entered into by the Company relate to regulated operations and any resulting gains or losses are recorded in rate stabilization accounts, subject to regulatory approval, and passed through to customers in future rates.

RISK MANAGEMENT

As approved by the regulator, derivatives are used to manage natural gas price risk in the natural gas transmission and distribution operations. The majority of the natural gas supply contracts have floating, rather than fixed prices. The Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in deferral accounts (CCRA and MCRA), and subject to regulatory approval, are passed through in future rates to customers.

Foreign currency risk in natural gas transmission and distribution operations relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through regulatory deferral accounts.

The Company's short-term borrowings and variable rate long-term debt are exposed to interest rate risk. The Company manages interest rate risk through the use of interest rate derivatives with payments and receipts under interest rate swap contracts being recognized as adjustments to financing costs.

The Company is exposed to credit risk in the event of non-performance by counterparties to its derivative financial instruments. Because it deals with high credit quality institutions in accordance with established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

12. RELATED PARTY TRANSACTIONS

(a) The Company received $4.1 million in 2007 (2006 – $4.1 million) from Terasen Gas (Vancouver Island) Inc. ("TGVI"), a subsidiary company of Terasen Inc., for transporting gas through the Company's pipeline system.

(b) The Company paid approximately $45.2 million during the year ended December 31, 2007 (2006 – $44.6 million) for customer care and billing services to a limited partnership. The Company's parent, Terasen Inc., holds a 30% interest in the limited partnership and jointly controls it. The Company is committed to pay approximately $43.0 million as base contract fees for 2008.

(c) The Company paid $8.5 million in 2007 (2006 – $8.5 million) to Terasen Inc. for management services.

(d) The Company charged affiliated companies $6.1 million in 2007 (2006 – $6.6 million) for management services.

Related party transactions are recorded at the exchange amount.

13. COMMITMENTS AND CONTINGENCIES

The Company has entered into operating leases for certain building space and natural gas transmission and distribution assets. In addition, the Company enters into gas purchase contracts. The following table sets forth the Company's operating lease and gas purchase obligations due in the years indicated:

	Operating leases	Purchase obligations	Total
2008	$ 15.7	$ 471.7	$ 487.4
2009	15.2	22.2	37.4
2010	14.9	-	14.9
2011	14.6	-	14.6
2012	14.3	-	14.3
2013 and later	93.3	-	93.3
	$ 168.0	$ 493.9	$ 661.9

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at December 31, 2007.

The Company received a Notice of Assessment dated July 31, 2006 from the British Columbia Social Service Tax authority for $37.1 million of additional provincial sales tax and interest on the Southern Crossing Pipeline, which was completed in 2000. The Company appealed this assessment and on March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform issued a decision in respect of the Company's appeal. The Minister reduced the assessment to $7.0 million including interest which has already been paid in full to avoid accruing further interest on the amount and has been included in other assets. The Minister's decision is currently under appeal by the Company to the Supreme Court of British Columbia.

13. COMMITMENTS AND CONTINGENCIES (CONTINUED)

A number of claims and lawsuits seeking damages and other relief are pending against the Company. Management is of the opinion, based upon information presently available, that it is unlikely that any liability, to the extent not provided for through insurance or otherwise, would be material in relation to the Company's consolidated financial statements.

CONSOLIDATED FINANCIAL STATEMENTS OF

TERASEN GAS INC.

YEARS ENDED DECEMBER 31, 2008 AND 2007

MANAGEMENT'S REPORT

Financial Reporting

Management is responsible for the accompanying consolidated financial statements. These financial statements have been prepared in conformity with Canadian generally accepted accounting principles and, where appropriate, include amounts that are based on management's best estimates and judgments.

The Board of Directors, through its Audit Committee, oversees Management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to the Company's Management regarding the preparation and presentation of the consolidated financial statements.

The Company's independent auditors, Ernst and Young, LLP, conducted their audit in accordance with Canadian generally accepted auditing standards. Their report outlines the scope of their audit and gives their opinion on the consolidated financial statements.

Signed:

Signed: R.L. (Randy) Jespersen

President and CEO

Signed:

Signed: Scott A. Thomson

Vice President, Regulatory Affairs
and Chief Financial Officer

Vancouver, Canada
February 3, 2009

AUDITORS' REPORT

To the Shareholders' of

Terasen Gas Inc.

We have audited the consolidated balance sheets of **Terasen Gas Inc.** as at December 31, 2008 and 2007 and the consolidated statements of earnings and comprehensive earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Vancouver, Canada,
January 30, 2009

Chartered Accountants

TERASEN GAS INC.
CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE EARNINGS

In millions of Canadian dollars *Years ended December 31*	**2008**	2007
Revenues		
Natural gas transmission and distribution	**$ 1,664.6**	$ 1,524.6
Expenses		
Cost of natural gas	**1,152.1**	1,017.3
Operation and maintenance	**175.8**	169.8
Depreciation and amortization	**78.3**	78.5
Property and other taxes	**44.8**	44.5
	1,451.0	1,310.1
Operating income	**213.6**	214.5
Financing costs (note 9)	**110.4**	106.8
Gain on sale of property, plant and equipment	**-**	(8.0)
Earnings before income taxes	**103.2**	115.7
Income tax expense (note 10)	**11.7**	37.5
Net earnings and comprehensive earnings	**$ 91.5**	$ 78.2

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

In millions of Canadian dollars *Years ended December 31*	**2008**	2007
Retained earnings, beginning of year	**$ 41.1**	$ 72.3
Adjustment to retained earnings (note 1)	**-**	1.5
	41.1	73.8
Net earnings and comprehensive earnings	**91.5**	78.2
	132.6	152.0
Dividends on common shares	**(100.0)**	(110.9)
Retained earnings, end of year	**$ 32.6**	$ 41.1

The accompanying notes are an integral part of these consolidated financial statements.

TERASEN GAS INC.
CONSOLIDATED BALANCE SHEETS

In millions of Canadian dollars *Years ended December 31*	**2008**	2007
Assets		
Current assets		
Cash and short-term investments	**$ 13.1**	$ 5.6
Accounts receivable	**345.9**	310.1
Inventories of gas in storage and supplies	**192.3**	180.8
Prepaid expenses	**2.8**	3.9
Current portion of rate stabilization accounts (note 3)	**53.9**	61.1
	608.0	561.5
Property, plant and equipment (note 2)	**2,432.3**	2,386.5
Rate stabilization accounts (note 3)	**-**	11.8
Other assets (note 4)	**68.6**	62.6
	$ 3,108.9	$ 3,022.4
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term notes	**$ 238.5**	$ 305.0
Accounts payable and accrued liabilities	**365.9**	331.2
Income and other taxes payable	**65.5**	38.6
Current portion of rate stabilization accounts (note 3)	**23.7**	-
Current portion of long-term debt (note 5)	**61.8**	189.7
	755.4	864.5
Long-term debt (note 5)	**1,339.9**	1,150.9
Rate stabilization accounts (note 3)	**7.7**	-
Other long-term liabilities and deferred credits (note 6)	**130.4**	128.3
Future income taxes	**0.5**	0.5
	2,233.9	2,144.2
Shareholders' equity		
Share capital (note 7)	**594.0**	594.0
Contributed surplus (note 7)	**248.4**	243.1
Retained earnings	**32.6**	41.1
	875.0	878.2
	$ 3,108.9	$ 3,022.4

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board:

Signed: R.L. (Randy) Jespersen Director

Signed: Harold Calla Director

TERASEN GAS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions of Canadian dollars *Years ended December 31*	**2008**	2007
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$ 91.5**	$ 78.2
Adjustments for non-cash items		
Depreciation and amortization	**78.3**	78.5
Gain on sale of property, plant and equipment	**-**	(8.0)
Other	**(4.6)**	(2.5)
	165.2	146.2
Changes in working capital	**33.3**	(28.3)
	198.5	117.9
Investing activities		
Property, plant and equipment	**(122.1)**	(108.4)
Proceeds from sale of land	**14.1**	-
Other assets and deferred credits	**22.4**	11.1
	(85.6)	(97.3)
Financing activities		
(Decrease) increase in short-term notes	**(66.5)**	88.0
Increase of long-term debt	**250.0**	251.4
Reduction of long-term debt	**(188.9)**	(250.0)
Dividends on common shares	**(100.0)**	(110.9)
	(105.4)	(21.5)
Increase (decrease) in cash	**7.5**	(0.9)
Cash and short-term investments at beginning of year	**5.6**	6.5
Cash and short-term investments at end of year	**$ 13.1**	$ 5.6
Supplemental cash flow information		
Interest paid in the year	**$ 109.3**	$ 106.0
Income taxes paid in the year	**13.0**	26.6
Non-cash transactions		
Mark to market on certain gas derivatives deferred in rate-stabilization accounts	**$ 4.5**	$ (61.2)
Property, plant and equipment purchases included in accounts payable and accrued liabilities	**3.0**	(0.3)
Net non cash proceeds arising on the sale of property	**-**	8.0

Cash is defined as cash and short-term investments.

The accompanying notes are an integral part of these consolidated financial statements.

1. SIGNIFICANT ACCOUNTING POLICIES

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses in the financial statements, as well as the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and reflect the following summary of significant accounting policies.

On February 26, 2007, Knight Inc. (formerly known as Kinder Morgan Inc.), Terasen Inc.'s former parent announced that it had entered into a definitive agreement with Fortis Inc. to sell Terasen Inc. and its principal natural gas transmission and distribution assets, including its subsidiaries Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. as well as other activities including Terasen Energy Services. The sale did not include the petroleum transportation subsidiaries nor investments under the Kinder Morgan Canada name. The transaction closed on May 17, 2007.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Terasen Gas Inc. ("Terasen Gas" or "the Company") and its subsidiaries, including Terasen Gas (Squamish) Inc. ("Squamish"). On January 1, 2007, the Company and its subsidiary, Squamish, were amalgamated.

Certain comparative figures have been reclassified to conform with the current year's presentation.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants ("CICA").

a) Section 3862, *Financial Instruments – Disclosures*, and Section 3863, *Financial Instruments – Presentation*, require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed. The new disclosures are included in Note 11.

b) Section 1535, *Capital Disclosures,* requires the Company to disclose additional information about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding the Company's objectives, policies and processes for managing capital. The new disclosures are in Note 11.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

c) Section 3031, *Inventories,* requires inventories to be measured at the lower of cost or net realizable value, disallows the use of a last-in first-out inventory costing methodology, and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This standard is to be applied retrospectively. As at January 1, 2008, supplies and other inventories of $6.6 million ($5.8 million as at January 1, 2007) were reclassified to property, plant and equipment from inventory on the balance sheet as they are held for the development, construction, maintenance and repair of other property, plant and equipment. During the year ended December 31, 2008, gas in storage inventories of $1,152.1 million (2007 - $1,017.3 million) were expensed and reported in cost of natural gas on the consolidated statement of earnings and comprehensive earnings.

FINANCIAL INSTRUMENTS

The Company utilizes derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices.

a) Section 3855, *Financial Instruments – Recognition and Measurement*, prescribes the criteria for recognition and presentation of financial instruments on the balance sheet and the measurement of financial instruments according to prescribed classifications. This section also addresses how financial instruments are measured subsequent to initial recognition and how the gains and losses are recognized.

   The Company is required to designate its financial instruments into one of the following five categories: held for trading; available for sale; held to maturity; loans and receivables; and other financial liabilities. All financial instruments are to be initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value with any change in fair value recorded in net earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

   All derivative financial instruments are recorded on the balance sheet at fair value. Mark-to-market adjustments on these instruments are included in net earnings, unless the instruments are designated as part of a cash flow hedge relationship, and then the effective portion of changes in fair value are recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in net earnings. For regulated financial instruments, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates, is subject to regulatory deferral treatment to be recovered from or refunded to customers in future rates.

   In accordance with the standard's transitional provisions, the Company recognizes as separate assets and liabilities only embedded derivatives acquired or substantively modified on or after January 1, 2003.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The Company has designated its financial instruments as follows:

- Cash and short-term investments are classified as "*Held for Trading*" and are recorded at fair value. Due to the relatively short period to maturity of these financial instruments the carrying values approximate their fair values.
- Accounts receivable and long-term receivables are classified as *"Loans and Receivables"*. These financial assets are recorded at values that approximate their amortized cost using the effective interest method.
- Short-term notes, accounts payable and accrued liabilities, long-term debt, and related issue costs are classified as "*Other Financial Liabilities*". These financial liabilities are recorded at values that approximate their amortized cost using the effective interest method.

  Deferred financing costs will be taken into earnings using the effective interest method over the life of the related debt. Prior to January 1, 2007, deferred financing costs were amortized using the straight-line method of amortization. As allowed by the standard a one-time adjustment of $1.5 million has been made to retained earnings to reflect the difference between the straight-line method and the effective interest method of amortization prior to January 1, 2007.

  The Company recognizes transaction costs associated with financial assets and liabilities, that are classified as other than held for trading, as an adjustment to the cost of those financial assets and liabilities recorded on the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument.

b) Section 1530, *Comprehensive Income*, requires the presentation of a statement of comprehensive income and provides guidance for the reporting and display of other comprehensive income. Comprehensive income represents the change in equity of an enterprise during a period from transactions and other events arising from non-owner sources including gains and losses arising on translation of self-sustaining foreign operations, gains and losses from changes in fair value of available for sale financial assets and changes in fair value of the effective portion of cash flow hedging instruments. The Company has not recognized any adjustments through other comprehensive income for the years ended December 31, 2008 and 2007.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

c) Section 3865, *Hedges,* specifies the criteria under which hedge accounting may be applied, how hedge accounting should be performed under permitted hedging strategies and the required disclosures. The majority of the Company's cash flow hedges are for the purchase of natural gas. Given that the Company is subject to rate regulation, the ineffective portion of changes in the fair value of these hedges is deferred as an asset or liability until it is settled, offset by an asset or liability on behalf of customers. Upon settlement, the recognized gain or loss is recorded as a regulatory asset or liability and is collected from or refunded to ratepayers in subsequent periods. The Company recognized an additional liability of $1.1 million to counterparties for unrealized losses related to gas purchase hedges at January 1, 2007 and an amount recoverable from ratepayers of $1.1 million. Amounts recoverable from ratepayers are recorded in rate stabilization accounts.

   The Company utilizes cash flow hedges to hedge the variability in interest payments on the underlying debt instruments. Cash flow hedges for rate regulated businesses are recorded in Other assets with the offset to Other long- term liabilities and deferred credits. The adoption of this new standard on January 1, 2007 increased Other assets by $0.8 million and increased Other long-term liabilities and deferred credits by $0.8 million.

REGULATION

The Company is subject to the regulation of the British Columbia Utilities Commission ("the BCUC"), an independent regulatory authority. The Company has a multi-year agreement that expires at the end of 2009. This multi-year agreement is a cost-of-service based agreement with allowed rates of return on approved rate base set by the BCUC. For 2008, the allowed ROE was set at 8.62% (2007 – 8.37%). The allowed rate of return is based on a notional debt-equity ratio of 64.99% debt and 35.01% equity. The Company has an annual review process for rate approvals and allowed rates of return are reset annually, unless directed differently by the BCUC. For 2009, the allowed ROE has been set at 8.47%.

The BCUC exercises statutory authority over such matters as rates of return, construction and operation of facilities, accounting practices, rates, and contractual agreements with customers. Rates are bundled to include transmission and distribution services, where applicable.

In order to recognize the economic effects of regulation, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under GAAP for non-regulated businesses.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in other assets whereas current regulatory assets are rate stabilization accounts which are recorded as current portion of rate stabilization accounts. Regulatory liabilities are recorded in other long-term liabilities and deferred credits.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The impacts of rate regulation on the Company's operations for the twelve months ending December 31, 2008 and 2007 and as at December 31, 2008 and 2007 are described in the Significant Accounting Policies, and in Note 2 "Property, Plant and Equipment", Note 3 "Rate Stabilization Accounts", Note 4 "Other Assets", Note 6 "Other Long-Term Liabilities and Deferred Credits", Note 8 "Employee Benefit Plans", Note 9 "Financing Costs", and Note 10 "Income Taxes".

INVENTORIES

Inventories of gas in storage are valued at weighted-average cost. The cost of gas in storage is recovered from customers in future rates.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures for system expansions, betterments and replacements, an allocation of overhead costs and an allowance for funds used during construction. When allowed by the BCUC, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

Depreciation of regulated assets is recorded on a straight-line basis over their useful lives. Depreciation rates for regulated assets are approved by the respective regulator.

The cost of regulated depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation, as is any gain or loss incurred on disposal.

IMPAIRMENT OF LONG-LIVED ASSETS

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. There was no impairment of long-lived assets for the years ended December 31, 2008 and 2007.

ASSET RETIREMENT OBLIGATIONS

The Company will recognize the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Company will concurrently recognize a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset. The fair value of the asset retirement obligation is to be estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Changes in the obligation due to the passage of time are to be recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are to be recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Company's natural gas transmission and distribution systems are not currently determinable, the Company has not recognized an asset retirement obligation at December 31, 2008 and 2007. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

RATE STABILIZATION ACCOUNTS

The Company is authorized by the BCUC to maintain rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility. The Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual versus forecast use for residential and commercial customers.

The Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in rates. The two accounts segregate costs that are allocable to all sales customers (MCRA) and all residential customers and certain commercial and industrial customers for whom Terasen Gas acquires gas supply (CCRA).

All rate stabilization account balances are recovered through rates as approved by the BCUC.

DEFERRED CHARGES

The Company defers certain charges which the regulatory authorities or contractual arrangements require or permit to be recovered through future rates. Deferred charges are amortized over various periods as approved by the BCUC and depending on the nature of the charges.

Deferred charges not subject to regulation relate to projects which are expected to benefit future periods and will be capitalized on completion, expensed on project abandonment, or amortized over their useful lives.

REVENUE RECOGNITION

The Company recognizes revenues when products have been delivered or services have been performed.

Revenues from natural gas sales are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year and are adjusted for the RSAM and other BCUC approved orders.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

POST-EMPLOYMENT BENEFIT PLANS

The Company sponsors a number of employee benefits plans. These plans include both defined benefit and defined contribution pension plans, and various other post-retirement benefit plans.

The cost of pensions and other post-retirement benefits earned by employees is actuarially determined as the employee provides service. The Company uses the projected benefit method based on years of service and estimates of expected returns on plan assets, salary escalation, retirement age of employees, mortality and expected future health-care costs. The discount rate used to value liabilities is based on AA Corporate bond yields. The Company accrues the cost of defined benefit pensions and post-employment benefits as the employee provides services, except when the BCUC requires costs to be expensed as paid.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets as of December 31, 2008 is calculated as the average of the market value of invested assets at December 31, 2008 and two actuarially determined extrapolated market values of invested assets at December 31, 2008. The two extrapolated market values are calculated by using the market value of invested assets at December 31, 2006 rolled forward to December 31, 2008 using 2007 and 2008 net contributions and assumed investment returns, and the market value of invested assets at December 31, 2007 rolled forward to December 31, 2008 using 2008 net contributions and assumed investment returns. These three amounts are then averaged and reported as the market-related value of plan assets used in calculating net benefit expense. Additionally, the Company compares the average market-related value to the underlying market value at the end of the period. If the difference between the average market-related value and the actual market value is greater or less than 20% of the actual market value, then any difference is amortized over the expected average remaining service life of the employee group covered by the plan.

Adjustments, in excess of 10% of the greater of the accrued benefit obligation and plan asset value, that result from plan amendments, changes in assumptions and experience gains and losses, are amortized over the expected average remaining service life of the employee group covered by the plan. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

Defined contribution plan costs are expensed by the Company as contributions are payable.

INCOME TAXES

The Company accounts for and recover income tax expense in rates as prescribed by the BCUC for ratemaking purposes. This includes accounting for income taxes by the taxes payable method and accounting for certain deferral and rate stabilization accounts on a net of realized tax basis, as approved by the BCUC. Therefore, future income taxes related to temporary differences are not recorded. The taxes payable method is followed as there is reasonable expectation that all future income taxes will be recovered in rates when they become payable.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Under the asset and liability method of accounting for income taxes, future income tax assets and liabilities are determined based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured at the tax rate that is expected to apply when the temporary differences reverse.

VARIABLE INTEREST ENTITIES

The Company has performed a review of the entities with whom it conducts business and has concluded that there are no entities that are required to be consolidated or variable interests that are required to be disclosed under the requirements of the Guideline.

FUTURE ACCOUNTING PRONOUNCEMENTS

a) *International Financial Reporting Standards ("IFRS"):* In February 2008, the Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011.

   The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section - *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to Exposure Draft.

   Terasen Gas, along with Fortis, is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Terasen Gas does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required as well as systems changes that may be necessary to gather and process the information.

b) *Rate-Regulated Operations:* In March 2007, the AcSB issued an Exposure Draft on rate-regulated operations that proposed: (i) the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, of the CICA Handbook providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation be removed; (ii) the explicit guidance for rate-regulated operations provided in Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*, be removed; and (iii) Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation*, be retained as is. The AcSB has also observed that relying on US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* ("FAS 71"), as another source of Canadian GAAP in the absence of CICA Handbook guidance addressing the specific circumstances of entities subject to rate regulation, is consistent with Section 1100 when the qualifying criteria of FAS 71 are met.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

In August 2007, the AcSB issued a Decision Summary on the Exposure Draft that supported the removal of the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, and the amendment to Section 3465, *Income Taxes,* to recognize future income tax liabilities and assets as well as an offsetting regulatory asset or liabilities for entities subject to rate regulation. Both changes will apply prospectively for fiscal years beginning on or after January 1, 2009. It was also decided that the current guidance pertaining to property, plant and equipment and disposal of long-lived assets and discontinued operations, consolidated financial statements be maintained and that the existing AcG-19 will not be withdrawn from the Handbook but that the guidance will be updated as a result of the other changes.

The AcSB also decided that the final Background Information and Basis for Conclusions associated with its rate regulation project would not express any views of the AcSB regarding the status of US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, as an "other source of GAAP" within the Canadian GAAP hierarchy.

Effective January 1, 2009, the impact on the Company of the amendment to Section 3465, *Income Taxes,* will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to or recovered from customers in future gas rates. Currently, the Company uses the taxes payable method of accounting for income taxes on regulated earnings. The estimated effect on the Company's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2008, would have been an increase in future tax liabilities of $261.8 million, including those associated with income taxes that will become payable on future revenues as they are collected from customers when the tax timing differences reverse. There would also be a corresponding increase in regulatory assets. Terasen Gas is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate regulated operations.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Company must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, 3061, 3465, and 3475. All assets and liabilities arising from rate regulation do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. These assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Company's consolidated financial statements if it had adopted the removal of the temporary exemption in Section 1100, for the year ended December 31, 2008. Terasen Gas is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate-regulated operations.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

c) Effective January 1, 2009, the Company will be adopting the new CICA Handbook Section 3064 – *Goodwill and Intangible Assets* which converges GAAP for goodwill and intangible assets with IFRS. The new standard provides for more comprehensive guidance on intangible assets, in particular for internally developed intangible assets. The Company is still assessing the financial reporting impact of adopting this standard.

2. PROPERTY, PLANT AND EQUIPMENT

2008	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas transmission and distribution systems	**2.35%**	**$ 2,833.7**	**$ 657.7**	**$ 2,176.0**
Plant, buildings and equipment	**6.25%**	**247.7**	**101.4**	**146.3**
Land and land rights	**0.00%**	**83.2**	**1.4**	**81.8**
Assets under construction	**-**	**28.2**	**-**	**28.2**
		$ 3,192.8	**$ 760.5**	**$ 2,432.3**

2007	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book Value
Natural gas transmission and distribution systems	2.34%	$ 2,759.5	$ 634.3	$ 2,125.2
Plant, buildings and equipment	7.41%	251.7	92.6	159.1
Land and land rights	0.00%	82.3	1.4	80.9
Assets under construction	-	21.3	-	21.3
		$ 3,114.8	$ 728.3	$ 2,386.5

As allowed by the regulators, during the year ended December 31, 2008 the Company capitalized an allowance for equity funds during construction at approved rates of $1.0 million (2007 - $0.8 million) and approved capitalized overhead of $27.7 million (2007 - $27.5 million), with offsetting inclusions in earnings.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

3. RATE STABILIZATION ACCOUNTS

	2008	2007
Current Assets		
RSAM	**$ -**	$ 5.9
CCRA	**53.9**	34.8
MCRA	**-**	20.4
	53.9	61.1
Long-Term Assets		
RSAM	**-**	11.8
Current Liabilities		
MCRA	**(23.7)**	-
Long-Term Liabilities		
RSAM	**(7.7)**	-
Net rate stabilization accounts	**$ 22.5**	$ 72.9

The current portion of the rate stabilization accounts represents the amounts expected to be recovered or refunded in rates over the next year. Actual recoveries (refunds) will vary depending on natural gas consumption and recovery amounts approved by the BCUC. Rate stabilization accounts are presented net of tax, where applicable.

The RSAM account is anticipated to be refunded in rates over three years. Refund of the RSAM balance is dependent upon annually approved rates and actual gas consumption volumes. The MCRA and CCRA accounts are anticipated to be fully recovered or paid within the next fiscal year.

In the absence of rate regulation, the costs in the rate stabilization accounts above would have been expensed as incurred which would have resulted in increased natural gas transmission and distribution revenues of $631.4 million (2007 – $568.6 million), increased cost of natural gas of $551.7 million (2007 - $555.8 million), increased income tax expense of $24.8 million (2007 – $4.1 million) and decreased other comprehensive income of $4.4 million (2007 – increased $61.2 million) related to the gas derivatives.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

4. OTHER ASSETS

	2008	2007
Deferred charges		
Subject to rate regulation and approved for recovery in rates		
Income taxes recoverable on post-employment benefits	**$ 17.7**	$ 15.5
Residential unbundling costs	**6.5**	8.6
Replacement transportation agreement	**0.7**	1.3
Commercial commodity unbundling costs	**-**	1.2
Other items approved for recovery in rates	**7.8**	6.1
Subject to rate regulation but not yet approved for recovery in rates		
Southern Crossing Pipeline PST Reassessment	**7.3**	7.2
	40.0	39.9
Long-term receivables	**9.1**	9.2
Pension assets (Note 8)	**19.5**	13.5
	$ 68.6	$ 62.6

Amortization of these deferred charges in rates for the year ended December 31, 2008 totalled $2.1 million (2007 - $2.6 million).

The deferral account for income taxes on post-employment benefits relates to income tax amounts on post employment benefit expense. The BCUC allows post-employment benefits to be collected from customers through rates calculated on the accrual basis, rather than a cash paid basis, which produces a timing difference for income tax purposes. Since the Company accounts for income taxes using the taxes payable basis of accounting, the tax effect of this timing difference is included in other assets, and will be reduced as cash payments for post-employment benefits exceed required accruals and amounts collected from customers in rates.

The residential and commercial commodity unbundling costs deferred are costs incurred to develop a third-party marketer alternative for residential and commercial customers to purchase natural gas from suppliers other than the Company. The BCUC has approved the recovery of these costs in rates over a three-year period.

The deferral account for the replacement transportation agreement relates to amounts that the Company is allowed to recover from customers in rates in order to cover any shortfall in revenues relative to a minimum amount approved by the BCUC on the Company's Southern Crossing Pipeline ("SCP"). The deferral account is being amortized and recovered in rates over a five-year period, of which one year remains at December 31, 2008.

The deferral account for the SCP PST reassessment relates to a payment made in regards to a possible reassessment of additional provincial sales tax on the SCP. See Note 13. In 2006, the Company made a payment of $10 million pending resolution of the appeal as a good faith payment in order to forestall an order from the Province of British Columbia (the "Province") to provide full payment or security. During 2007, the assessment was reduced to $7.0 million and the overpayment was refunded to the Company. Incremental costs associated with the appeal are being deferred. Depending on the success of the appeal, the Company will either be refunded this payment from the Province or alternatively expects to recover the costs from customers in future rates.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

4. OTHER ASSETS (CONTINUED)

Deferred charges and deferred credits for rate regulated entities that have been aggregated in the table above and in Note 6 relate to more than 37 deferral accounts, none of which exceed $1.6 million individually. All of these accounts have been approved by regulators in prior annual rate approvals or orders and are being amortized over various periods depending on the nature of the costs.

In the absence of rate regulation, the deferred charges in the above table would have been recorded in income, except for the costs related to the pension asset and the SCP PST Reassessment. This would have resulted in increased natural gas transmission and distribution revenues of $8.6 million (2007 - $2.1 million), increased operation and maintenance costs $3.1 million (2007 - $12.9 million), decreased depreciation and amortization of $2.1 million (2007 - $2.6 million), increased financing costs of $0.2 million (2007 - $0.6 million), and increased income tax expense of $5.3 million (2007 – decreased $1.3 million).

5. LONG-TERM DEBT

	2008	2007
(a) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2015	**$ 74.9**	$ 74.9
10.30% Series B, due September 30, 2016	**200.0**	200.0
(b) Debentures and Medium Term Note Debentures:		
10.75% Series E, due June 8, 2009	**59.9**	59.9
6.20% Series 9, due June 2, 2008	**-**	188.0
6.95% Series 11, due September 21, 2029	**150.0**	150.0
6.50% Series 18, due May 1, 2034	**150.0**	150.0
5.90% Series 19, due February 26, 2035	**150.0**	150.0
5.55% Series 21, due September 25, 2036	**120.0**	120.0
6.00% Series 22, due October 2, 2037	**250.0**	250.0
5.80% Series 23, due May 13, 2038	**250.0**	-
Obligations under capital leases, at 4.54% (2007 – 5.61%)	**9.7**	8.6
Total long-term debt	**1,414.5**	1,351.4
Less: current portion of long-term debt	**61.8**	189.7
Less: long term debt issue costs	**12.8**	10.8
	$ 1,339.9	$ 1,150.9

(a) PURCHASE MONEY MORTGAGES:

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Company's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

(b) DEBENTURES AND MEDIUM TERM NOTE DEBENTURES:

The Company's debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

5. LONG-TERM DEBT (CONTINUED)

On May 13, 2008, Terasen Gas issued $250.0 million of Medium Term Note Debentures at a coupon interest rate of 5.80%. The debentures mature on May 13, 2038 and are unsecured and subject to the restrictions of the Trust Indenture. The proceeds were used to repay Terasen Gas' Series 9 Medium Term Debentures which matured on June 2, 2008 and the remainder of the proceeds were used to pay down Terasen Gas' operating line.

On October 2, 2007, Terasen Gas issued $250.0 million of Medium Term Note Debentures at a coupon interest rate of 6.00%. The debentures mature on October 2, 2037 and are unsecured and subject to restrictions of the Trust Indenture. The proceeds were used to repay Terasen Gas' Series 13 and Series 20 Medium Term Debentures which matured in 2007.

On August 24, 2007, Terasen Gas renegotiated and extended its credit facility for five years with similar terms to the original facility and common for such term credit facilities. The $500 million unsecured committed revolving credit facility is with a syndicate of banks and matures in August 2012. In 2008, under the terms of the agreement, the facility was extended to mature in August 2013.

Long-term debt issue costs are amortized using the effective interest rate method as discussed in Note 1. The Company's Series B Purchase Money Mortgages, Series E Debentures, and Series 11, Series 18, Series 19, Series 21, Series 22 and Series 23 Medium Term Note Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Required principal repayments over the next five years and thereafter are as follows:

2009	$ 61.8
2010	1.9
2011	1.9
2012	1.9
2013	1.9
Thereafter	1,345.1

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

6. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS

	2008	2007
Pension and other post-employment benefit liabilities (Note 8)	**$ 55.3**	$ 47.6
Deferred gains on sale of natural gas transmission and distribution assets	**46.3**	50.5
Deferred credits		
Subject to rate regulation and approved for recovery in rates		
Earnings Sharing Mechanism	**10.7**	12.5
SCP Net Mitigation Revenue	**6.6**	4.4
SCP West to East Transmission Revenues	**2.5**	0.9
Deferred Interest on MCRA	**1.8**	1.7
Deferred Interest Mechanism	**1.4**	0.1
Customer Benefit from Land Sale	**0.5**	1.7
Large Corporation Tax Elimination	**-**	2.1
Pension Cost Variance	**-**	2.3
Other items approved for recovery in rates	**5.3**	4.5
	$ 130.4	$ 128.3

The deferred gains on sale of natural gas transmission and distribution assets occurred upon the sale of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $70.5 million on combined cash proceeds of $141.1 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 13.

Amortization of these deferred credits in rates for the year ended December 31, 2008 totalled $5.1 million (2007 - $5.4 million).

The Earnings Sharing Mechanism is a mechanism agreed to in the Company's multi-year agreement to share, on a 50/50 basis, amounts earned by the Company on its regulated activities that exceed or are less than amounts allowed by the BCUC in the cost-of-service allowed return calculations. These amounts are shared on an after-tax basis, and are returned to customers in rates.

The SCP net mitigation revenue is revenue that is received from third parties for the use of the SCP transportation capacity that has not been utilized by the firm transportation agreement customers. This account is used to record differences between actual revenues from SCP mitigation and what has been approved in the current revenue requirement. Amounts are being amortized to income over 5 years.

The SCP west to east transmission revenue is revenue that is received from third parties for the use of the SCP west to east transmission system. This account is used to record differences between actual revenues from SCP west to east transmission system and what has been approved in the current revenue requirement. Amounts are being amortized to income over 5 years.

The deferred interest on MCRA is the interest calculated on the difference between the actual and forecasted average balance of the MCRA account multiplied by the composite interest rate.

The Company has a deferred interest mechanism which has been approved by the BCUC which requires that variances due to differences in long-term borrowings and long-term and short-term interest rates from those that have been approved in rates be returned to customers in future rates. The impact of this mechanism was to increase financing costs for the year ended December 31, 2008 by $2.4 million (2007 – nil). The balance of the account is being amortized on a straight-line basis over three years.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

6. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS (CONTINUED)

The customer benefit from land sale represents the customers' portion of the net of tax gain on the sale of surplus land that will be refunded to customers by the first quarter of 2009.

The large corporation tax elimination costs resulted from the federal government eliminating the tax on large corporations in 2006. The BCUC allows large corporation tax to be recovered from customers through rates. These costs were collected from customers through rates in 2006 and now are owed back to customers in future rates upon the elimination of the large corporation tax.

The pension cost variance account accumulates differences between pension expense that is approved for recovery in rates and actuarial pension expense. Amounts are recovered in rates in the following year.

In the absence of rate regulation, the other long-term liabilities and deferred credits in the above table would have been recorded in income, aside for the pension and other post-employment benefit liabilities and the deferred gains on sale of natural gas transmission and distribution assets. This would have resulted in increased natural gas transmission and distribution revenues of $3.9 million (2007 - $6.2 million), decreased cost of natural gas of $0.7 million (2007 – increased $0.4 million), decreased operation and maintenance costs of nil (2007 – $2.3 million), decreased property and other taxes of nil (2007 - $1.1 million), increased depreciation and amortization of $5.1 million (2007 - $5.4 million), decreased financing costs of $2.4 million (2007 – $0.4 million) and increased income tax expense of $3.3 million (2007 – $1.8 million).

7. SHARE CAPITAL AND CONTRIBUTED SURPLUS

AUTHORIZED SHARE CAPITAL

The Company is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value.

	2008	2007
Common shares, 59,591,732 shares issued	**$ 594.0**	$ 594.0

CONTRIBUTED SURPLUS

Income tax benefits in the amount of $5.3 million (2007 - $8.0 million) relating to transactions with entities under common control were recorded as a credit to contributed surplus in 2008.

DIVIDEND POLICY

As part of its approval of the acquisition of Terasen Inc. by Knight, Inc., and subsequently of Terasen Inc. by Fortis Inc. from Knight Inc., the BCUC imposed a number of conditions intended to ring-fence the Company from its parent companies. These restrictions included a prohibition on the payment of dividends unless the Company has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. The Company must maintain a percentage of common equity to total capital that is at least as much as that determined by the BCUC from time to time for ratemaking purposes. Dividends from the Company will not be allowed by the regulator if the requisite equity is not in place. The Company's dividend policy is intended to ensure that it maintains at least as much common equity as that deemed by the BCUC for rate-making purposes.

8. EMPLOYEE BENEFIT PLANS

The Company is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. The Company also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan:

DEFINED BENEFIT PLANS

Retirement benefits under the defined benefit plans are based on employees' years of credited service and remuneration. Company contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were at December 31, 2005 and December 31, 2007 and the dates of the next required valuations are December 31, 2008 and December 31, 2010. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 10.2 years (2007 – 10.3 years).

Effective January 1, 2007 all employees became participants in a new defined benefit pension plan in which costs are split evenly between the employees and employer. All current employees were grandfathered in their respective defined contribution and defined benefit plans and those plans were closed to all new members. The most recent actuarial valuation of the new defined benefit pension plan for funding purposes was May 17, 2007 and the date of the next required valuation is December 31, 2009.

DEFINED CONTRIBUTION PLAN

Effective in 2000, all new non-union employees became members of defined contribution pension plans. Company contributions to the plan are based upon employee age and pensionable earnings. Effective January 1, 2007, all new employees of the Company became members of the new defined benefit plan described above. Company contributions to the plan are based upon employee age and pensionable earnings for employees.

SUPPLEMENTAL PLANS

Certain employees are eligible to receive supplemental benefits under both the defined benefit and defined contribution plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and are secured by letters of credit.

OTHER POST-EMPLOYMENT BENEFITS

The Company provides retired employees with other post-employment benefits that include, depending on circumstances, supplemental health, and life insurance coverage. Post-employment benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health care cost escalation. The most recent actuarial valuations were completed as at December 31, 2005 and the date of the next required valuation is December 31, 2008. The expected weighted average remaining service life of employees covered by these benefit plans is 9.0 years (2007 - 9.0 years).

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 each year. The financial positions of the employee defined benefit pension plans and other benefit plans are presented in aggregate in the tables below:

	Defined benefit pension plans		Other benefit plans	
	2008	2007	**2008**	2007
Plan assets				
Fair value, beginning of year	**$ 237.4**	$ 228.9	**$ -**	$ -
Actual return on plan assets	**(30.5)**	8.1	**-**	-
Company contributions	**6.2**	5.8	**1.6**	1.2
Contributions by members	**4.7**	4.1	**-**	-
Benefit payments	**(9.6)**	(9.5)	**(1.4)**	(1.1)
Other	**(0.3)**	-	**(0.2)**	(0.1)
Fair value, end of year	**207.9**	237.4	**-**	-
Accrued benefit obligation				
Obligation, beginning of year	**236.0**	227.3	**68.7**	68.2
Current service cost	**6.2**	6.6	**1.2**	1.3
Interest cost	**12.5**	11.5	**3.6**	3.4
Contributions by members	**4.7**	4.1	**-**	-
Benefit payments	**(9.6)**	(9.5)	**(1.4)**	(1.1)
Actuarial gains	**(13.7)**	(4.0)	**(10.2)**	(3.1)
Balance, end of year	**236.1**	236.0	**61.9**	68.7
Funded status - (deficiency) plan surplus	**(28.2)**	1.4	**(61.9)**	(68.7)
Unamortized transitional (benefit) obligation	**(6.9)**	(8.7)	**-**	1.5
Unamortized actuarial loss	**49.3**	16.2	**10.3**	22.3
Unamortized past service costs	**2.2**	2.7	**(0.6)**	(0.8)
Accrued benefit asset (liability)	**$ 16.4**	$ 11.6	**$(52.2)**	$ (45.7)
Represented by				
Pension assets	**$ 19.5**	$ 13.5	**$-**	$ -
Accrued benefit liability	**(3.1)**	(1.9)	**(52.2)**	(45.7)
	$ 16.4	$ 11.6	**$(52.2)**	$ (45.7)

The net accrued benefit liability is included in other long-term liabilities and deferred credits (Note 6) and the pension asset is included in other assets (Note 4).

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

Included in the accrued benefit obligation and fair value of the plan assets at year-end are the following amounts in respect of plans with accrued benefit obligations in excess of fair value of assets:

	Pension benefit plans		Other benefit plans	
	2008	2007	**2008**	2007
Accrued benefit obligations:				
Unfunded plans	**$ 8.9**	$ 9.8	**$ 61.9**	$ 68.7
Funded plans	**227.2**	226.2	**-**	-
	236.1	236.0	**$ 61.9**	68.7
Fair value of plan assets	**207.9**	237.4	**-**	-
Funded status (deficit) surplus	**$ (28.2)**	$ 1.4	**$ (61.9)**	$ (68.7)

The accrued benefit obligations for certain unfunded pension benefit plans are secured by letters of credit.

The net benefit plan expense is as follows:

	Pension benefit plans		Other benefit plans	
	2008	2007	**2008**	2007
Current service cost	**$ 6.2**	$ 6.6	**$ 1.2**	$ 1.3
Interest cost on projected benefit obligations	**12.5**	11.5	**3.6**	3.4
Actual loss (return) on plan assets	**30.5**	(8.1)	**-**	-
Net actuarial losses (gains)	**(13.7)**	(4.0)	**(10.2)**	(3.1)
Other	**0.3**	-	**0.1**	0.1
Net benefit plan (income) expense before adjustments	**35.8**	6.0	**(5.3)**	1.7
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return on plan assets	**(47.5)**	(7.6)	**-**	-
Difference between actual and recognized actuarial losses in year	**14.4**	4.7	**11.9**	5.4
Difference between actual and recognized past service costs in year	**0.5**	0.5	**(0.1)**	(0.1)
Amortization of transitional (benefit) obligation	**(1.8)**	(1.8)	**1.6**	1.6
Net benefit plan expense	**$ 1.4**	**$ 1.8**	**$ 8.1**	$ 8.6

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

BENEFIT PLAN ASSETS

The weighted-average asset allocation by asset category of the Company's defined benefit pension plans and other funded benefit plans is as follows:

	Defined Benefit Pension Plans	
	2008	2007
Equity securities	**48%**	56%
Fixed income securities	**40%**	35%
Other assets	**12%**	9%
Total assets	**100%**	100%

The investment policy for benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Company's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost-effective manner while not compromising the security of the respective plans. The pension plans utilize external investment managers to manage the investment policy. Assets in the plan are held in trust by independent third parties.

The pension plans do not directly hold any shares of the Company's parent.

SIGNIFICANT ASSUMPTIONS

The discount rate assumption used in determining pension and post-retirement benefit obligations and net benefit expense reflects the market yields, as of the measurement date, on high-quality debt instruments. The expected rate of return on plan assets assumption is reviewed annually by management, in conjunction with actuaries. The assumption is based on the expected returns for the various asset classes, weighted by the portfolio allocation.

The weighted average significant actuarial assumptions used to determine the accrued benefit obligation and the benefit plan expense are as follows:

	Pension benefit plans		Other benefit plans	
	2008	2007	**2008**	2007
Accrued benefit obligation				
Discount rate at December 31, based on AA Corporate bonds	**6.25%**	5.25%	**6.25%**	5.25%
Rate of compensation increase	**3.13%**	3.63%	**-**	-
Net benefit plan expense				
Discount rate at January 1, based on AA Corporate bonds	**5.25%**	5.00%	**5.25%**	5.00%
Expected rate of return on plan assets	**7.25%**	7.25%	**-**	-

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

8. EMPLOYEE BENEFIT PLANS (CONTINUED)

The assumed health-care cost trend rates for other post-employment benefit plans are as follows:

	2008	2007
Extended health benefits		
Initial health care cost trend rate	**8.0%**	8.0%
Annual rate of decline in trend rate	**1.0%**	1.0%
Ultimate health care cost trend rate	**5.0%**	5.0%
Year that the rate reaches the ultimate trend rate	**2012**	2011
Medical Services Plan Benefits Premium trend rate	**4.0%**	4.0%

A one percentage-point change in assumed health-care cost trend rates would have the following effects:

2008	One percentage-point increase	One percentage-point decrease
Effect on the total of the service costs and interest cost components of the benefit plan expense	**$ 0.7**	**$ (0.6)**
Effect on accrued benefit obligation	**8.5**	**(7.5)**

CASH FLOWS

Total cash contributions for employee benefit plans consist of:

	Employee benefit plans	
	2008	2007
Funded plans	**$ 5.6**	$ 5.0
Beneficiaries of unfunded plans	**2.2**	2.0
Total	**$ 7.8**	$ 7.0

The contributions for 2009 are anticipated to be approximately the same as 2008 for defined pension benefit plans and other benefit plans (Note 13).

IMPACT OF RATE REGULATION

As required by the regulator, the Company is required under its approved cost of service model to defer the amounts of pension benefit expense that exceed or are less than the amounts approved by the regulator to be recovered in rates each year. During the year ended December 31, 2008 the Company has deferred pension expense of $0.4 million (2007 – less than amount approved $1.5 million) that exceeded the amount approved by the regulator to be recovered in rates in 2009.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

9. FINANCING COSTS

	2008	2007
Interest and expense on long-term debt	**$ 99.1**	$ 101.1
Interest on short-term debt	**12.3**	6.5
Interest capitalized	**(1.0)**	(0.8)
	$ 110.4	$ 106.8

As allowed by the regulator, during the year ended December 31, 2008, the Company capitalized interest for borrowing requirements for construction of assets that have not been included in rate base of $1.0 million (2007 - $0.8 million).

10. INCOME TAXES

VARIATION IN EFFECTIVE INCOME TAX RATE

Consolidated income taxes vary from the amount that would be computed by applying the federal and provincial combined statutory income tax rate of 31.0% (2007 – 34.12%) to earnings before income taxes as shown in the following table:

	2008	2007
Earnings before income taxes	**$ 103.2**	$ 115.7
Combined statutory income tax rate	**31.0%**	34.12%
Combined income taxes at statutory rate	**$ 32.0**	$ 39.4
Decrease in income taxes resulting from capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	**(5.3)**	(4.5)
Quebec settlement (Note 13)	**(5.6)**	-
Impact of reassessments related to prior years	**(7.6)**	-
Non-deductible expenses and non-taxable income	**(0.7)**	(2.5)
Provincial income tax applicable to prior years	**-**	1.4
Other	**(1.1)**	3.7
Actual consolidated income taxes	**$ 11.7**	$ 37.5
Effective Income Tax Rate	**11.34%**	32.41%

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

10. INCOME TAXES (CONTINUED)

FUTURE INCOME TAXES

Currently, the Company uses the taxes payable method of accounting for income taxes on regulated earnings. The estimated effect on the Company's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2008, would have been an increase in future tax liabilities of $261.8 million, including those associated with income taxes that will become payable on future revenues as they are collected from customers when the tax timing differences reverse. There would also be a corresponding increase in regulatory assets.

11. FINANCIAL INSTRUMENTS

FAIR VALUE ESTIMATES

	December 31, 2008		December 31, 2007	
	Carrying Value	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and short-term investments [1]	**$ 13.1**	**$ 13.1**	$ 5.6	$ 5.6
Loans and receivables				
Accounts receivable [1,2]	**345.9**	**345.9**	310.1	310.1
Long-term receivables [1,2]	**9.1**	**9.1**	9.2	9.2
Other financial liabilities				
Short-term notes [1,2]	**238.5**	**238.5**	305.0	305.0
Accounts payable and accrued liabilities [1,2]	**365.9**	**365.9**	331.2	331.2
Long-term debt, including current portion [3,4,5]	**1,401.7**	**1,454.2**	1,340.6	1,550.3

1 Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.
2 Carrying value approximates amortized cost.
3 Carrying value is measured at amortized cost using the effective interest rate method.
4 Carrying value at December 31, 2008 is net of unamortized deferred financing costs of $12.8 million (2007 - $10.8 million). On January 1, 2007, deferred financing costs were reclassified from other assets in accordance with the transitional provisions of CICA Section 3855. The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.
5 Fair value is calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2008, or by using available quoted market prices.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

Interest expense associated with the Company's short-term borrowings and long-term debt is disclosed in Note 9 to these consolidated financial statements.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

11. FINANCIAL INSTRUMENTS (CONTINUED)

DERIVATIVE INSTRUMENTS

The Company hedges its exposure to fluctuations in natural gas prices through the use of derivative instruments. The table below indicates the valuation of the derivative instruments as at December 31, 2008.

Asset (Liability)			**December 31, 2008**		December 31, 2007	
	Number of swaps and options	Term to maturity (years)	Carrying Value	Fair Value	Carrying Value	Fair Value
Natural Gas Commodity Swaps and Options	180	Up to 3	**$ (70.7)**	**$ (70.7)**	$ (77.3)	$ (77.3)
Gas purchase contract premiums	66	Less than 3	**(6.2)**	**(6.2)**	4.8	4.8

The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates. The natural gas derivatives fair values have been determined using published market prices for natural gas commodities.

The derivatives entered into by the Company relate to regulated operations and any resulting gains or losses are recorded in rate stabilization accounts, subject to regulatory approval, and passed through to customers in future rates.

RISK MANAGEMENT

Exposure to credit risk, liquidity risk, market risk, and natural gas commodity price risk arises in the normal course of the Company's business. The Company enters into financial instruments to finance its operations in the normal course of business.

CREDIT RISK

Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. For cash and short term investments, derivative assets, accounts receivable, and other receivables due from customers, the Company's credit risk is limited to the carrying value on the balance sheet. The Company generally has a large and diversified customer base, which minimizes the concentration of credit risk.

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments, including natural gas commodity swaps and options. The Company is also exposed to credit risk on physical off-system sales. Because the Company deals with high credit-quality institutions, in accordance with established credit-approval practices, the Company does not expect any counterparties to fail to meet their obligations. Counter-party credit exposures are monitored by individual counterparty and by category of credit rating, and are subject to approved limits. The counter-parties with which the Company has significant transactions are A-rated entities or better. The Company uses netting arrangements to reduce credit risk and net settles payments with counter-parties where net settlement provisions exist.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

11. FINANCIAL INSTRUMENTS (CONTINUED)

In the case of commercial and industrial customers credit risk is managed by checking a company's creditworthiness and financial strength both before commencing and during the business relationship. For residential customers, creditworthiness is ascertained normally before commencing commodity delivery by an appropriate mix of internal and external information to determine the payment mechanism required to reduce credit risk to an acceptable level. Certain customers will only be accepted on a prepayment basis. The Company manages its exposure to credit risk associated with all customers by monitoring an aging of receivables and by monitoring groupings of customers according to method of payment or profile.

Receivables from customers are generally considered to be fully performing until such time as the payment that is due remains outstanding past the contractual due date. The contractual due date is generally 22 days

The ageing analysis of the Company's consolidated accounts receivable is as follows:

	December 31, 2008
Not past due	$ 333.8
Past due 0-30 days	12.5
Past due 31-60 days	2.0
Past due 61-90 days	0.8
Past due over 91 days	3.4
Subtotal accounts receivable	352.5
Less: allowance for doubtful accounts	(6.6)
	$ 345.9

LIQUIDITY RISK

Liquidity risk is the risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments. The Company's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate this risk, the Company had consolidated authorized lines of credit of $500.0 million (2007 - $500.0 million), as at December 31, 2008, of which $218.0 million (2007 - $152.0 million) was unused. The Company targets to have, on average, sufficient liquidity to allow it not to access the capital markets for a period of twelve months.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

11. FINANCIAL INSTRUMENTS (CONTINUED)

The following summary outlines the Company's credit facility.

Credit Facilities	**December 31, 2008**	December 31, 2007
Total credit facility	**$ 500.0**	$ 500.0
Credit facility utilized		
Short-term borrowings	**(238.5)**	(305.0)
Letters of credit outstanding	**(43.5)**	(43.0)
Credit facility available	**$ 218.0**	$ 152.0

Furthermore, the Company targets a strong investment-grade credit rating to maintain capital market access at reasonable interest rates. As at December 31, 2008, the Company's credit ratings were as follows:

Credit Ratings	**DBRS**	**Moody's**
Terasen Gas Inc.		
Commercial paper	R-1 (Low)	-
Secured long-term debt	A	A2
Unsecured long-term debt	A	A3

A downward change in the credit ratings of the Company by one level on January 1, 2008 would have decreased earnings for the year ended December 31, 2008 by $0.3 million.

The following is an analysis of the contractual maturities of the Company's financial liabilities as at December 31, 2008.

Financial Liabilities	≤ 1 year	>1-3 years	4-5 years	>5 years	Total
Short-term notes	$ 238.5	$ -	$ -	$ -	$ 238.5
Accounts payable and accrued liabilities	365.9	-	-	-	365.9
Long-term debt, including current portion	61.8	3.8	3.8	1,345.1	1,414.5
	$ 666.2	$ 3.8	$ 3.8	$1,345.1	$2,018.9
Derivative Financial Liabilities					
Commodity contracts	$ 58.2	$ 18.7	$ -	$ -	$ 76.9

11. FINANCIAL INSTRUMENTS (CONTINUED)

MARKET RISK

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in foreign exchange rates or market interest rates.

The Company's earnings are not exposed to changes in the US dollar to Canadian dollar exchange rate.

The Company's natural gas derivatives are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The following sensitivity analysis estimates the impact on the fair value of natural gas commodity swaps and options of a 5 percent appreciation and depreciation of the US dollar-to-Canadian dollar exchange rate, with all other variables remaining constant, for the year ended December 31, 2008. A 5 percent appreciation of the US dollar-to-Canadian dollar exchange rate would change the fair value of natural gas commodity swaps and options by moving the fair value further out of the money by $0.3 million. This would result in an increase in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts". A 5 percent depreciation of the US dollar-to-Canadian dollar exchange rate would change the fair value of natural gas commodity swaps and options by reducing the Company's out of the money position by $0.3 million. This would result in a decrease in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts".

The Company is exposed to interest rate risk associated with short-term borrowings and floating rate debt. The Company may enter into interest rate swaps to help reduce this risk. Approximately 100 per cent of the Company's operating facility is subject to interest rate risk while none of its long term debt is subject to interest rate risk. In aggregate, the Company attempts to maintain an exposure of not more than 20% of its debt portfolio in floating rate debt. A 50 basis point increase in interest rates would decrease earnings for the year ended December 31, 2008 by $1.1 million. Additionally, the Company has existing regulatory deferrals which would absorb the impact of interest rate changes.

COMMODITY PRICE RISK

The Company is exposed to risks associated with changes in the market price of natural gas as a result of the natural gas derivatives. The Company's price risk management strategy covers a term of 36 months and aims to (i) improve the likelihood that natural gas prices remain competitive with electricity rates, (ii) dampen price volatility on customer rates and (iii) reduce the risk of regional price disconnects. Any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in deferral accounts, and subject to regulatory approval, are passed through in future rates to customers. The accompanying Balance Sheet at December 31, 2008 includes a net deferral of $76.9 million included in the caption "Current Assets: Current Portion of Rate Stabilization Accounts" representing net unrealized losses on these hedges that are recoverable from customers through rates.

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

11. FINANCIAL INSTRUMENTS (CONTINUED)

The Company's exposure to market risk includes forward-looking statements and represents an estimate of possible changes in fair value that would occur assuming hypothetical future movements in commodity prices. The Company's views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

The following sensitivity analysis estimates the impact on the fair value of natural gas commodity swaps and options of an one dollar change in the value of the underlying price of natural gas, with all other variables remaining constant, for the year ended December 31, 2008. This analysis is for illustrative purposes only, as in practice market rates rarely change in isolation. If the price of natural gas decreased by one dollar per Gigajoule, the change in the fair value of natural gas commodity swaps and options would be to move further out of the money by $45.4 million. This would result in an increase in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts". If the price of natural gas increased by one dollar per Gigajoule, the change in the fair value of natural gas commodity swaps and options would be to reduce the Company's out of the money position by $47.8 million. This would result in a decrease in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts".

CAPITAL MANAGEMENT

The Company's principal business of regulated gas distribution utilities requires ongoing access to capital in order to allow it to fund the maintenance and expansion of infrastructure. In order to ensure access to capital is maintained, the Company targets a long-term consolidated capital structure of 35 percent equity, 65 percent debt and strong investment-grade credit ratings. As well, the Company has secured a multi-year committed credit facility to support short-term financing of capital expenditures and seasonal working capital requirements. The committed credit facility is available for general corporate purposes.

The Company maintains a capital structure in line with the deemed capital structure approved by the BCUC of 35 percent equity.

The consolidated capital structure of the Company is presented in the following table.

	December 31, 2008		December 31, 2007	
		(%)		*(%)*
Total debt and capital lease obligations (net of cash and short-term investments) [1]	**$ 1,627.1**	**65.0**	$ 1,640.0	65.0
Shareholder's equity	**875.0**	**35.0**	878.2	35.0
Total	**$ 2,502.1**	**100.0**	$ 2,518.2	100.0

[1] Includes long-term debt, including current portion, and short-term borrowings, net of cash and short-term investments

11. FINANCIAL INSTRUMENTS (CONTINUED)

Certain of the Company's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 75 percent of the Company's capital structure, as defined by the long-term debt agreements. The restrictions on the issuance of additional debt are generally based on an interest coverage being at least two times available net earnings. In addition, certain of the Company's credit agreements require maintenance of certain financial covenants such as a maximum percentage of debt to equity. As at December 31, 2008 and 2007, the Company was in compliance with these covenants.

The Company's credit ratings and credit facilities are disclosed under "Liquidity Risk" in Note 11.

12. RELATED PARTY TRANSACTIONS

a) The Company received $3.3 million in 2008 (2007 – $4.1 million) from Terasen Gas (Vancouver Island) Inc. ("TGVI"), a company under common control, for transporting gas through the Company's pipeline system.

b) The Company paid approximately $47.0 million during the year ended December 31, 2008 (2007 – $45.2 million) for customer care and billing services to a limited partnership. The Company's parent, Terasen Inc., holds a 30% interest in the limited partnership and jointly controls it. The Company is committed to pay approximately $43.6 million as base contract fees for 2009.

c) The Company paid $8.5 million in 2008 (2007 – $8.5 million) to Terasen Inc., the Company's parent, for management services.

d) The Company charged companies under common control $6.6 million in 2008 (2007 – $6.1 million) for management services.

e) The Company's indirect parent, Fortis Inc., grants stock options to certain employees of the Company under its stock option plans. For the year ended December 31, 2008, , the Company was charged, and recorded an expense of $0.3 million (2007 $0.1 million) for the fair value of the stock compensation granted by Fortis Inc

Related party transactions are recorded at the exchange amount.

13. COMMITMENTS AND CONTINGENCIES

The Company has entered into operating leases for certain building space and natural gas transmission and distribution assets. In addition, the Company enters into gas purchase contracts. The following table sets forth the Company's operating leases, gas purchase obligations and employee benefit plan contributions due in the years indicated:

(Tabular amounts in millions of Canadian dollars, except where stated otherwise)

13. COMMITMENTS AND CONTINGENCIES (CONTINUED)

	Operating leases	Purchase obligations	Employee benefit plans	Total
2009	$ 15.4	$ 360.4	$ 7.9	$ 383.7
2010	15.0	26.9	5.9	47.8
2011	14.7	22.8	-	37.5
2012	14.4	-	-	14.4
2013	13.5	-	-	13.5
Thereafter	85.5	-	-	85.5
	$ 158.5	$ 410.1	$ 13.8	$ 582.4

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at December 31, 2008. The employee benefit plan contributions have been estimated up to the date of the next actuarial valuation for each plan unless the valuation falls in the next twelve months then the Company has provided for an estimate of the contributions. Employee benefit plan contributions beyond the date of the next actuarial valuation cannot be accurately estimated.

The Company is disputing a $7.0 million assessment of B.C. Social Service Tax representing additional provincial sales tax and interest on the Southern Crossing Pipeline, which was completed in 2000. The amount was paid in full in 2006 to avoid the accrual of further interest and has been included in other assets. The matter is currently under appeal to the Supreme Court of British Columbia.

During the year the Company reached a settlement with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of retroactive amending Quebec tax legislation. In August 2008, the Company made payments of approximately $12.7 million to settle the tax liability. As a result of the tax settlement, an earnings benefit of $5.6 million was recorded during 2008.

A number of claims and lawsuits seeking damages and other relief are pending against the Company. Management is of the opinion, based upon information presently available; that it is unlikely that any liability, to the extent not provided for through insurance or otherwise, would be material in relation to the Company's consolidated financial statements.

Attachment 84.5

Customer Advisory Council Meeting

May 27, 2009

Agenda

8:30 a.m.	Continental Breakfast
9:00 a.m.	Introduction *(Doug Stout)*
9:05 a.m.	Customer Care Update *(Danielle Wensink)*
9:50 a.m.	New Business Opportunities *(John Turner, David Bennett)*
10:35 a.m.	Regulatory Update *(Scott Thomson)*
10:50 a.m.	Projects Update *(Cynthia Des Brisay)*
11:05 a.m.	Closing Remarks

A copy of today's presentation can be found at: www.terasengas.com

Customer Care & Services

Danielle Wensink
Customer Care & Services

May 27, 2009

Service Quality Indicators (SQIs)

Terasen Gas

	Performance Indicator	2009 YTD Actual	2009 Target
1	**Emergency Response Time** - Time Dispatched to Site - Emergency - Blowing Gas	22:00 minutes	**< 21:06 minutes**
2	**Speed of Answer – Emergency** (% of calls answered within 30 sec.)	98.5%	**> 95%**
3	**Speed of Answer – Non-Emergency** (% of calls answered within 30 sec.)	76.8%	**> 75%**
4	**Transmission Reportable Incidents**	0	**< 2**
5(a)	**Index of Customer Bills Not Meeting Criteria**	6.90	**< 5**
5(b)	**Percent of Transportation Customer Bills Accurate**	88.6%	**> 99.5%**
6	**Meter Exchange Appointment Activity**	87.2%	**> 92.2%**
7	**Accuracy of Transportation Meter Measurement First Report**	98.4%	**> 90.0%**
8	**Independent Customer Satisfaction Survey**	79.9%	**N/A**
9	**Number of Customer Complaints to BCUC**	21	**N/A**
10	**Number of Prior Period Adjustments**	11	**< 25**

	Directional Indicators	
1	Leaks per Kilometer of Distribution	0.0009
	Mains	17
2	Number of Third Party Distribution System Incidents	299

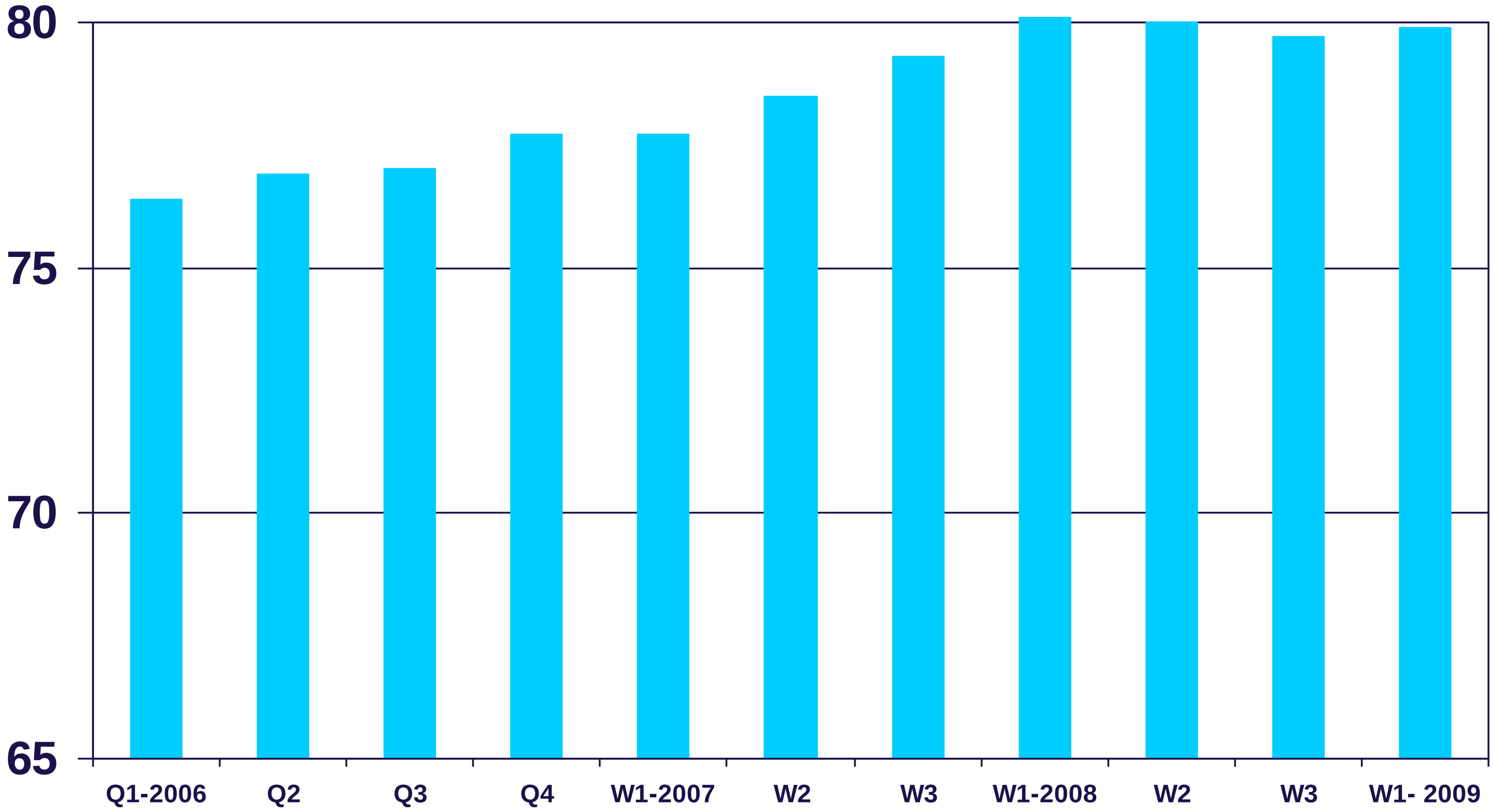
Distribution Measures

- Emergency Response Time
  - *Interior location events driving average response time slightly above target*
    - Outlying communities
    - After hours responses
  - *Construction crews assigned to more complex activities*
    - Can take longer to respond when assigned as first responder
- Meter Exchange Appointment Activity
  - *Activity currently below target due to overbooking of technicians resulting in missed appointments*
    - Fine-tuning appointment scheduling and system capacity within new mobile scheduling system for fieldwork

Billing Measures

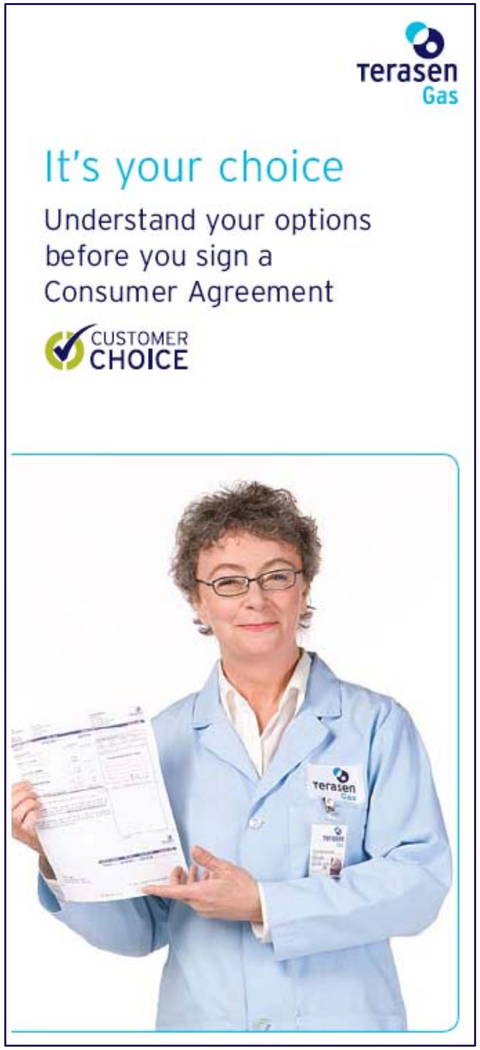
- Mass Market Billing Index & Transportation Billing Accuracy
  - *Year to date results driven primarily by late payment charge calculation error*
    - Result of CIS system technical upgrade late last year
    - Identified in January
    - System fix implemented in February
  - *Secondary impact was a PST / ICE Levy error*
    - Incorrectly charging above to first nations exempt customers
    - Identified and corrected in March

Customer Satisfaction Tracking



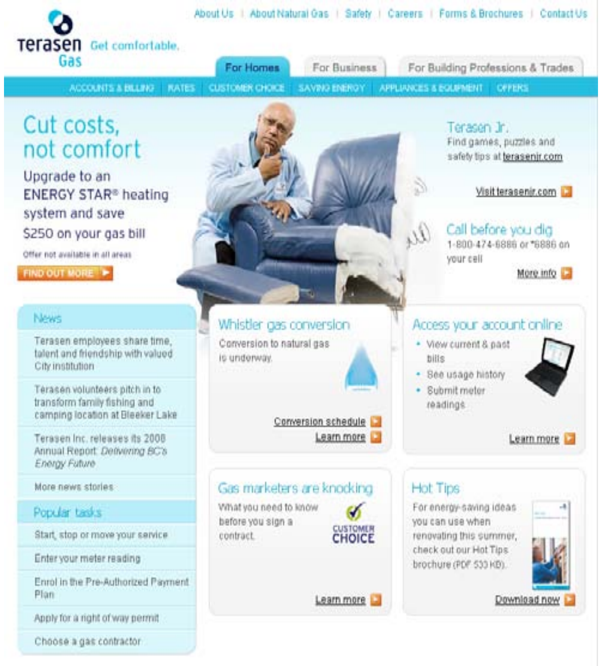
Recent Activities & Events

- Commodity rate adjustment
  - *Jan 1 – Fort Nelson, Revelstoke*
  - *Apr 1 – TGI, Fort Nelson, Revelstoke*
- Customer Choice education
  - *Spring newspaper advertising in 39 community papers*
  - *May bill inserts*
  - *Web advertising*
  - *Bill messages*



Recent Activities & Events

- Radio Campaign
  - *Promoted Energy Efficiency options for renovators*
    - Specific mention of the Furnace Upgrade program
  - *May 4 – May 15*
- Customer Research
  - *Service Channel Expectations & Preferences*
  - *Residential End Use Survey*
  - *Residential Customer Satisfaction Tracking – Wave 2, 2009*



Customer Care Enhancement Project

Danielle Wensink

Customer Care & Services

Project Overview

- Customer Care service delivery in-sourcing
  - *Establish internal call center and billing organization*
  - *Hire, train and house over 350 new employees*
  - *Operational “go live” beginning of 2012*
- In-source technology platforms and business processes
  - *Acquire and implement new CIS solution*

Key Drivers

- Market change
  - *Energy and environment policy changes*
  - *Expanded and more complex customer service offerings*
  - *Customer service expectations increasing*
- Ability to respond limited by existing solution
  - *Existing arrangement limits rapid and cost effective change*
  - *Current technology platform lagging the evolution of alternatives*
  - *Model does not facilitate close "customer touch"*
- Customer expectations and requirements continually change
  - *We need to ensure we can respond to change effectively*

Benefits

Terasen Gas

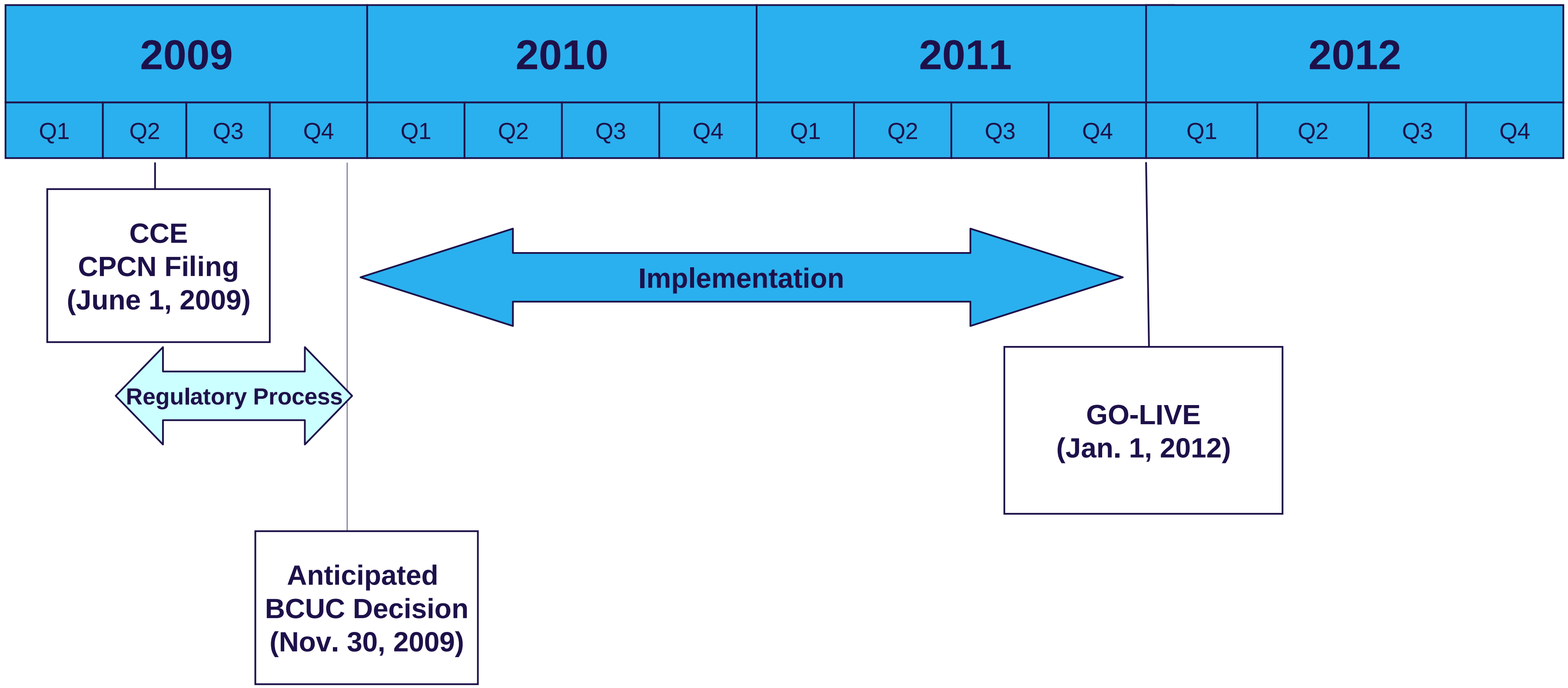
Customers Receive

- ***Greater scope of services***
  - **Improved communication channels**
  - **Enhanced self service options**
- ***Improved service levels***
  - **Regional knowledge**
  - **End to end business understanding**

Terasen Gas Receives

- ***Ownership of critical customer touch points***
- ***Improved capability to respond to increasing service expectations and market change***
- ***Greater control over pace, nature and cost of future change***
- ***Organizational flexibility***

Timeline



2009
2010
2011
2012
Q1
Q2
Q3
Q4
Q1
Q2
Q3
Q4
Q1
Q2
Q3
Q4
Q1
Q2
Q3
Q4
CCE
CPCN Filing
(June 1, 2009)
Regulatory Process
Anticipated
BCUC Decision
(Nov. 30, 2009)
Implementation
GO-LIVE
(Jan. 1, 2012)

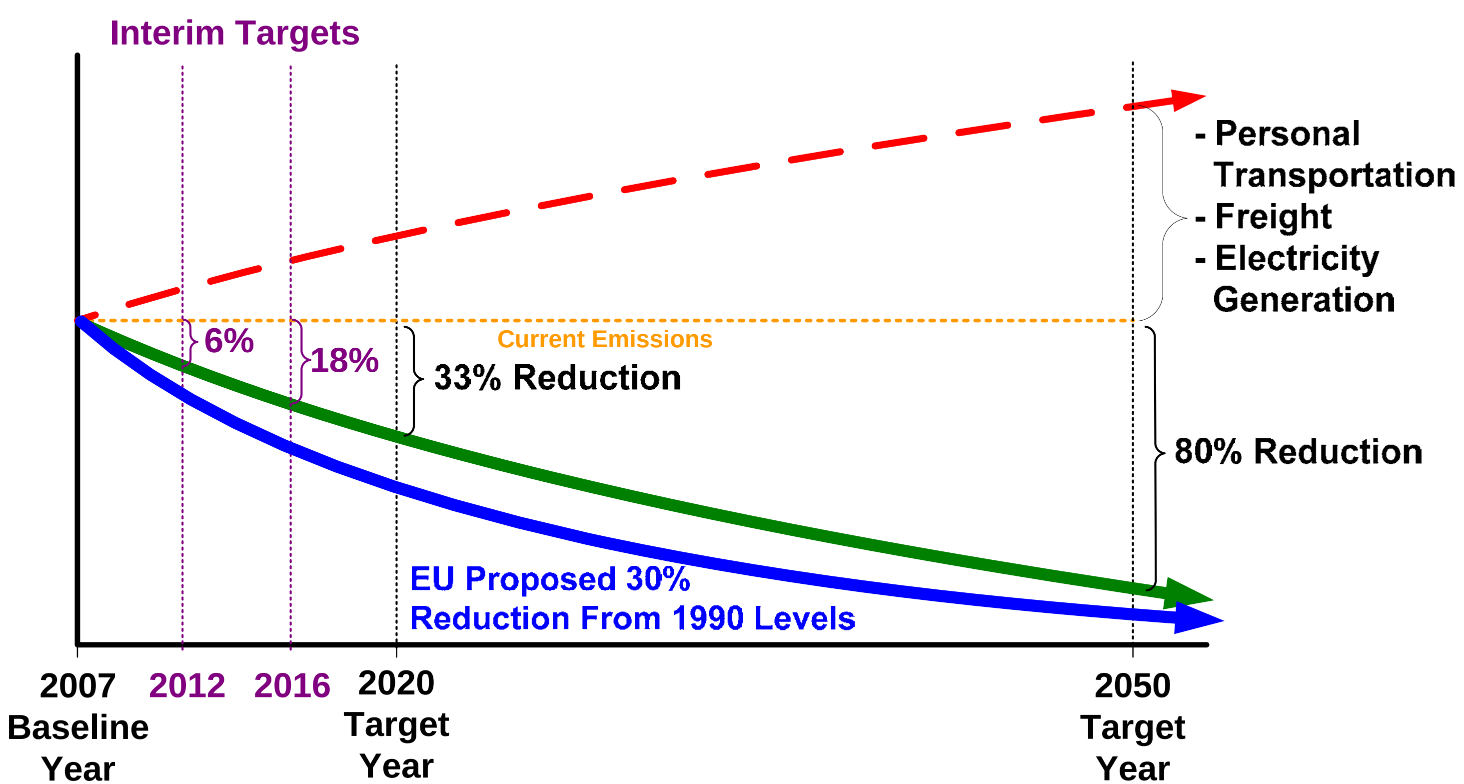
Customer Advisory Committee
Community Energy Solutions – Our Growth Strategy
- a "TSN turning point"

John Turner, Director, Customer Management & Sales

David Bennett, Director Resource Planning & Market Development

British Columbia Legislated Targets

- ***Reducing BC's GHG emissions by at least 33% below 2007 levels by 2020 and at least 80% below by 2050***



British Columbia Action to Targets

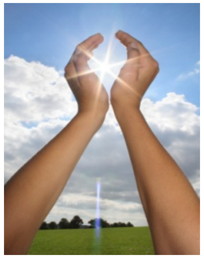
- ***Through significant pieces of climate action legislation***

- ***Includes carbon tax***

Cap and trade

Landfill Gas

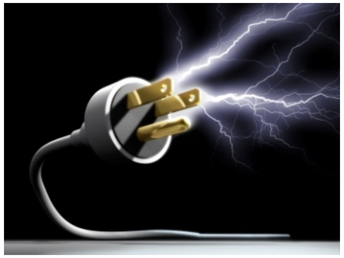
Energy Plan



Green Communities

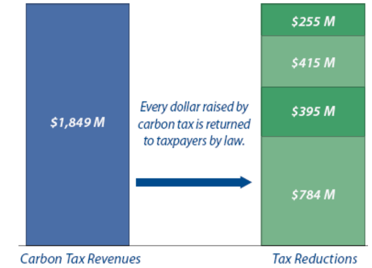
Low Carbon Fuel

Utilities Commission



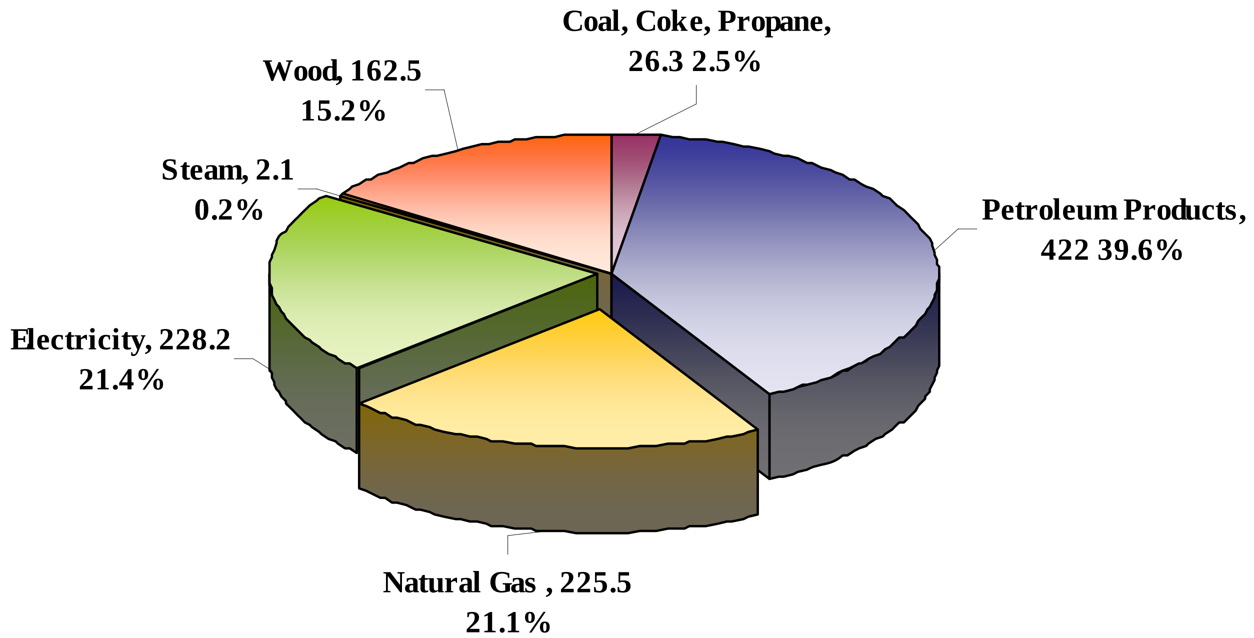
Tailpipe Standard

Carbon Tax Act



BC Energy Mix

terasen Gas



Fortis ≈ 10 PJ

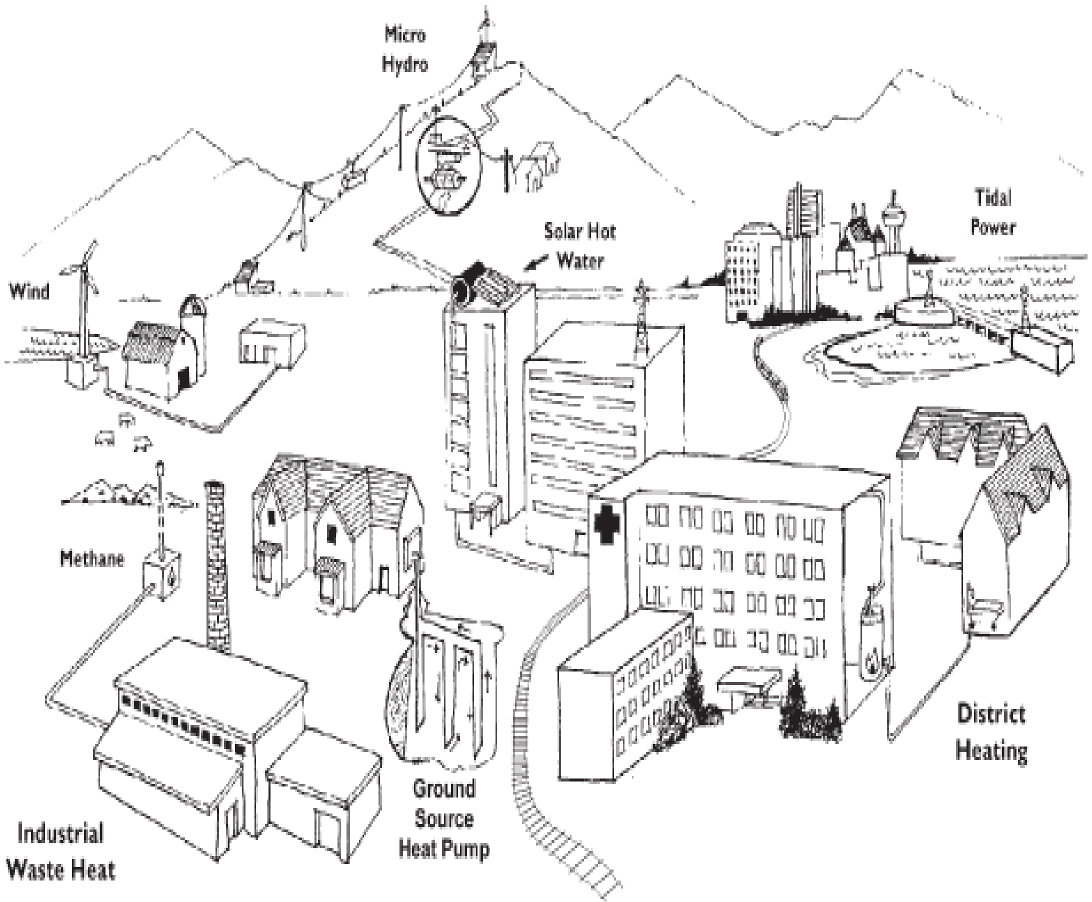
TG ≈ 215 PJ

Source: NRCan 2005 Database

BC Situation Summary & Response

- *BC Situation Summary:*
  - Very significant GHG reductions legislated
  - Equal use of electricity & natural gas today
  - Most of BC electricity is clean low-cost Hydro
  - Desire to preserve low cost electricity rates
- *Response:*
  - Transformation of thermal energy delivery
  - harness alternatives
  - reduce energy use
  - QUEST as an enabler
- *Why Terasen:*
  - Established energy provider in British Columbia

QUEST



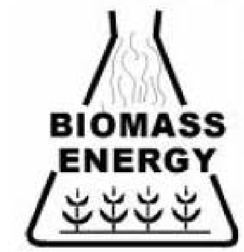
Source: Green Municipalities - A Guide to Green Infrastructure for Canadian Municipalities; prepared for the FCM by the Sheltair Group, May 2001

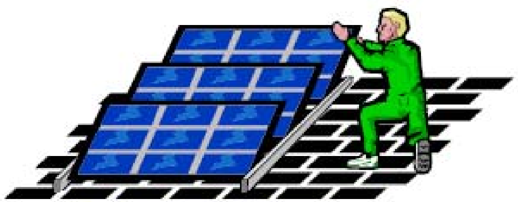
- Cascading of energy use between customer types
- Smaller scale systems closer to & within buildings
- Integrated with elements of buildings & other infrastructure systems
- Multiple local energy sources
- Augmented by gas & electricity grids
- Over 50% reduction in grid energy use.
- QUEST website:

  www.questcanada.org

Alternative Energy Options

Refrigeration Waste Heat





Solar energy

Biogas

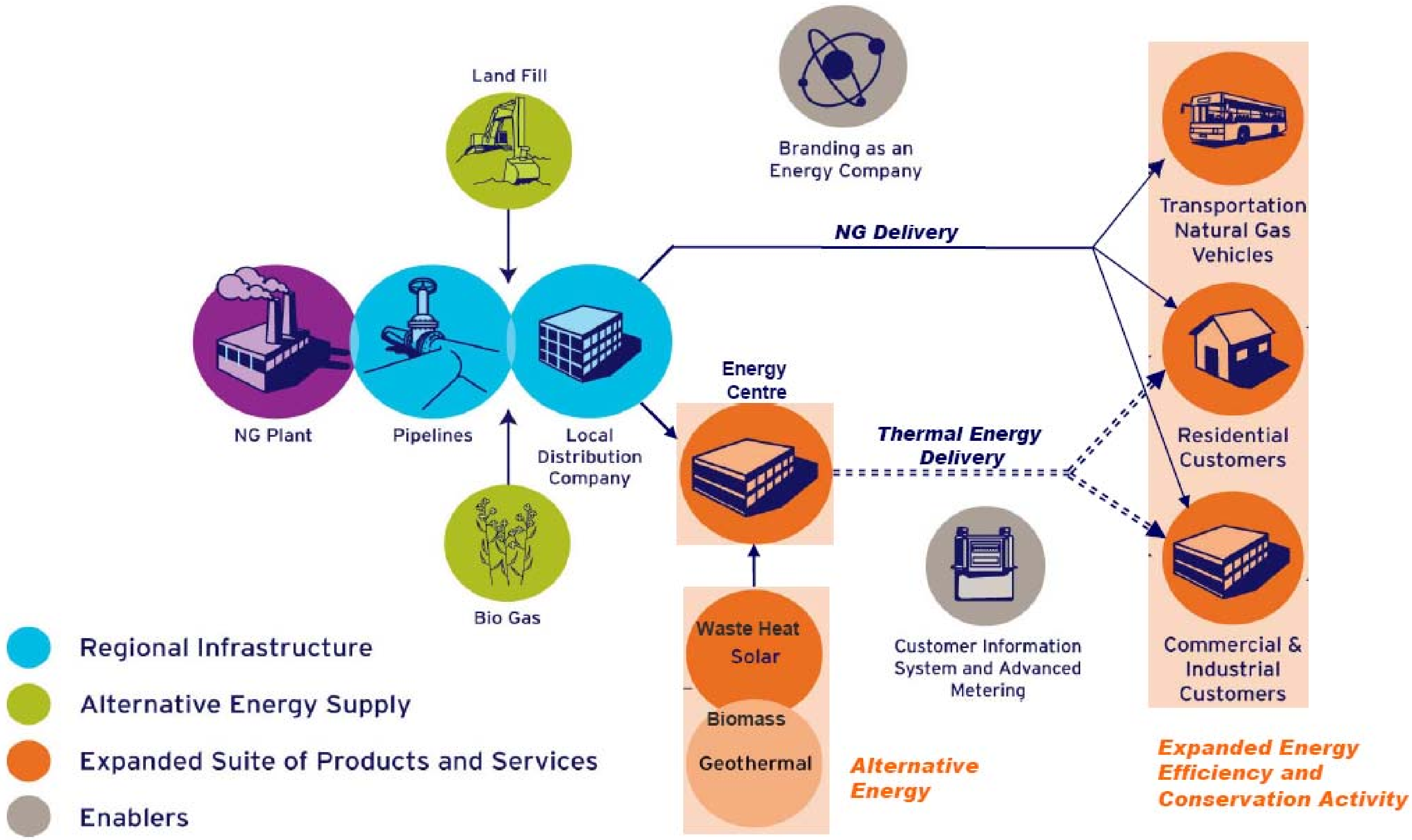
(sewage, landfill, agriculture)

Sewer heat

Industrial Waste Heat

Geo-exchange Water or Ground Loop

Terasen Approach



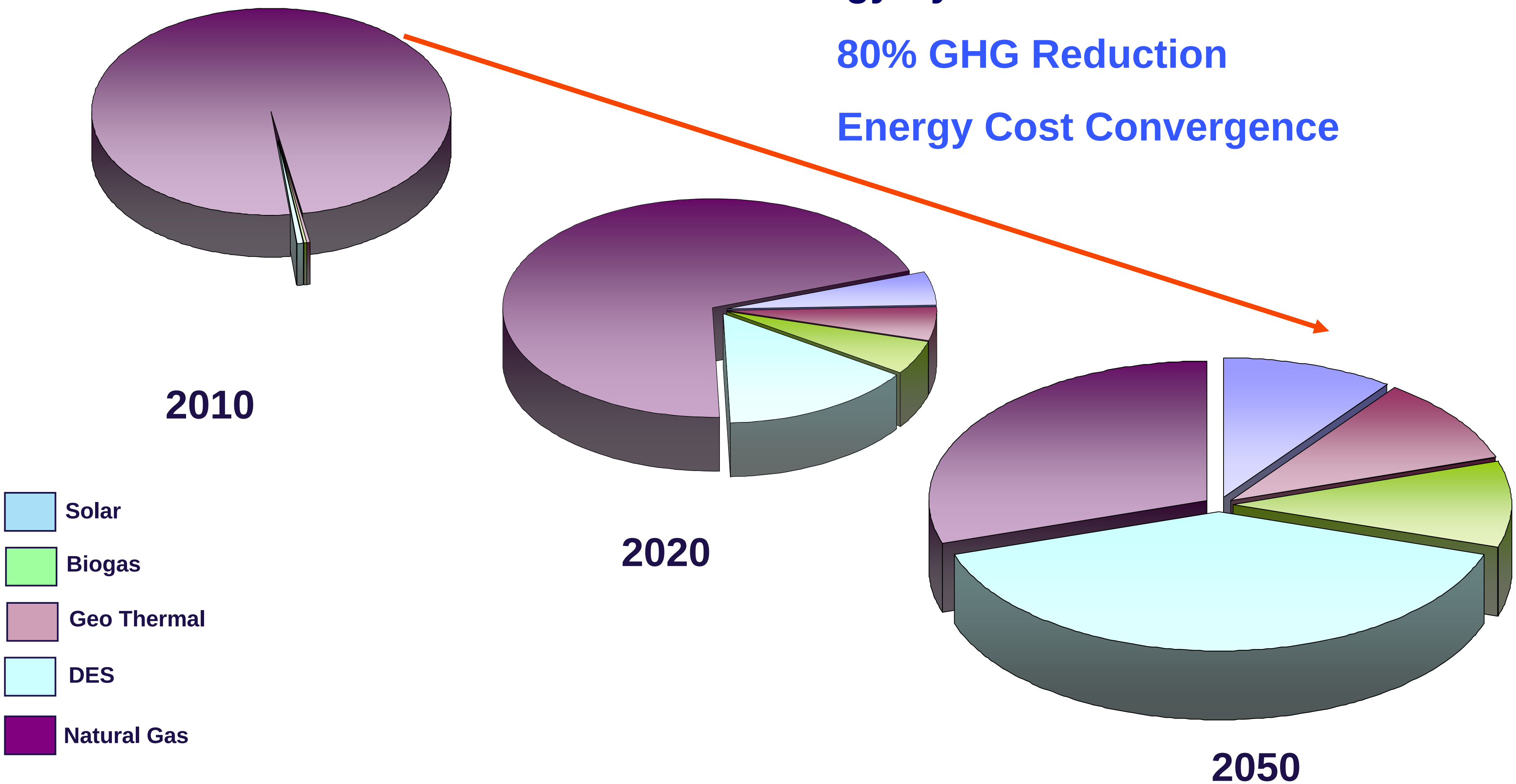
A Carbon Lean and Energy Diverse Future

terasen Gas

Energy System Evolution

80% GHG Reduction

Energy Cost Convergence



Biogas

Methane from organic material

Main Sources:

Anaerobic Digester Gas:

- *Waste water treatment plants*
- *Agricultural - farms and dairies*

Landfill Gas:

- *Gas collected from wells installed within landfill sites*

1st Pilot Project at Lions Gate Wastewater Treatment Plant

Transportation Applications for NG

Material Handling Equipment

Yard Trucks

Waste Haulers

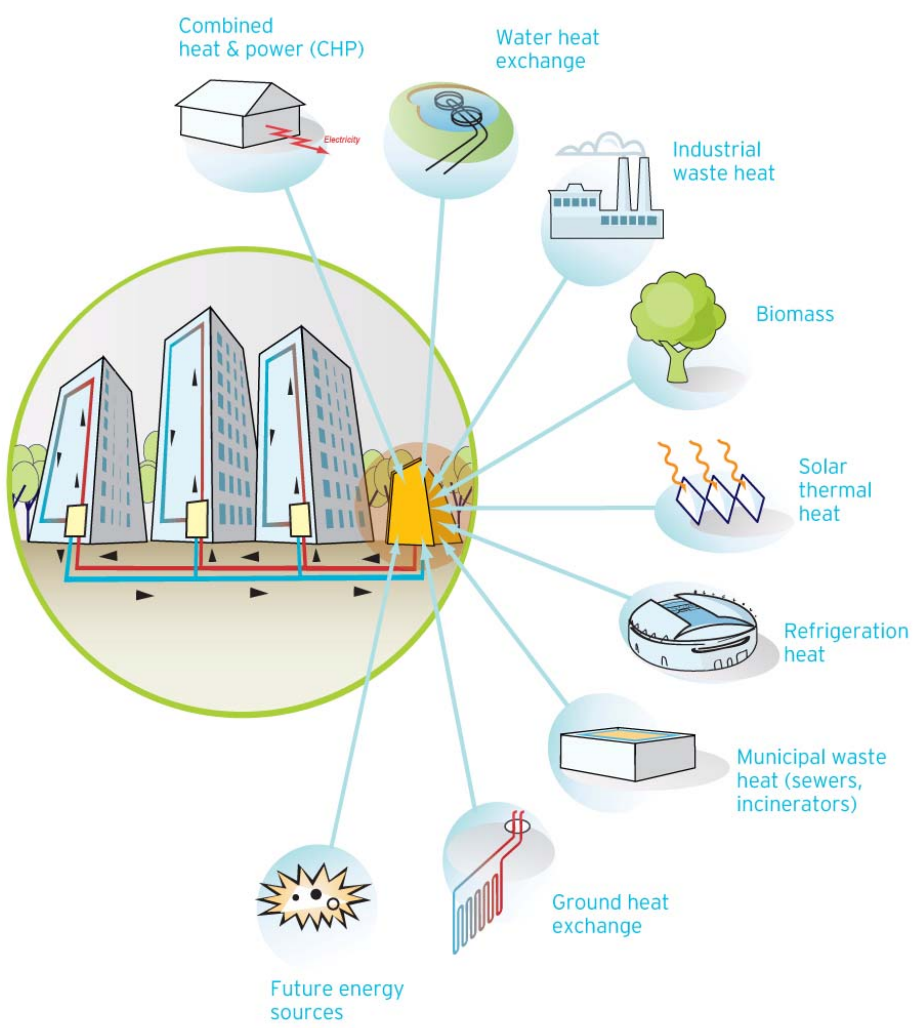
Transit Buses

Class 6/7 Trucks

Class 8 Trucks

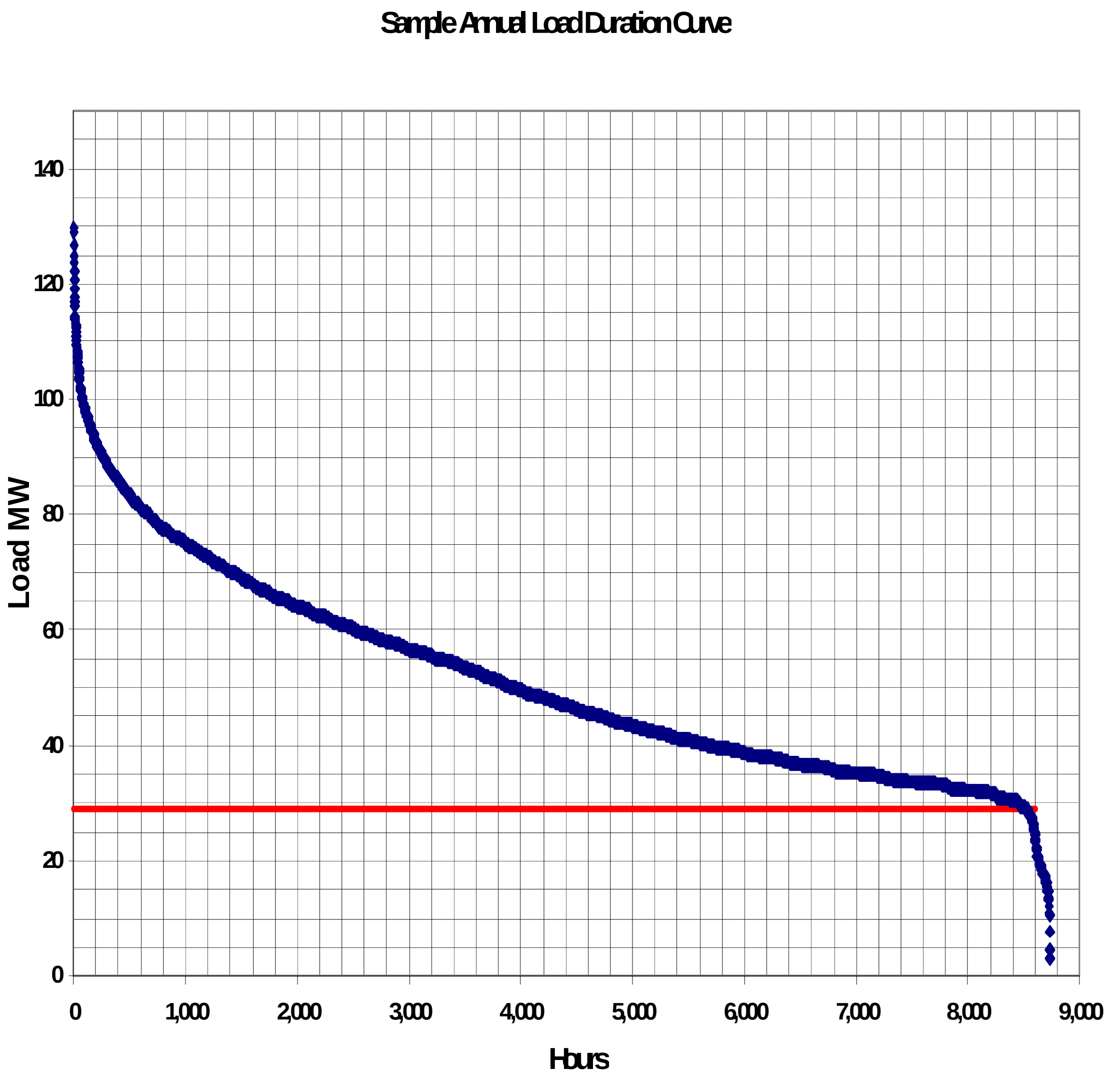
Pilot Project to use Tilbury LNG for Transportation Applications

Harnessing Alternative Energy



- **Thermal Energy Systems:**
  - ***Multiple energy sources***
  - ***Energy Centre generates usable thermal energy***
  - ***Thermal energy delivered via piped water:***
    - **Hot for high-grade heat sources; no cooling**
    - **Ambient for combined heating & cooling**
    - **Chilled for high-grade cooling sources & no heating**
  - ***Scale – one building to complete communities***

Alternative Energy - Cost Implications



Harnessing Alternatives:

- *High capital cost for Energy Centre*
- *"Free" energy?*
- *May not be firm supply*

Outcomes:

- *Size for base-load only*
- *Use conventional energy for peaking &/or 100% back-up*
- *Future flexibility essential for Energy Centre Capital cost barrier*
    - Terasen can solve

Terasen Large Scale Alternative Energy System Examples

terasen Gas

District Energy for Brownfield Re-development

- Location: Coquitlam, BC
- Type of Development:
  - *89 acre brownfield re-development*
    - **3,700** residential units,
    - 275,000 sq. ft of commercial/retail
    - 600,000 sq. ft. of business park/ light industrial
    - 16 acres of open space, parks and trails.
- Energy System:
  - *District Energy System to incorporate alternative energy sources integrated with natural gas:*
    - Local waste heat (industrial recycling plant)
    - Geothermal from groundwater or earth
    - Possibilities for biomass

Fraser Mills Site Plan

- Environmental Benefits
  - Reduced demand on BC's electricity grid
  - Savings of >8,200 tonnes of GHGs per year (equivalent to removing >2,500 cars from the road)

Terasen Large Scale Alternative Energy System Examples

Individual Geothermal Systems for Residential Development

- Location: Colwood, BC
- Type of Development:
  - *563 unit residential development*
  - *24 buildings*

Aquattro Site

Geothermal drilling

- Energy System:
  - Individual geothermal systems
    - Ground heat extraction integrated with natural gas
    - Progressive installation as community develops
- Environmental Benefits
  - Reduced demand on BC’s electricity grid
  - Savings of 2 tonnes of GHGs a year for each 2,000 square foot residential unit

Terasen Large Scale Alternative Energy System Examples

Expandable Energy System for Urban Infill

- Location: Victoria, BC
- Type of Development:
    - *New & existing buildings*
        - 631 new residential units,
        - 175,000 sq. ft of new commercial/retail
        - Multiple existing buildings adjacent to new development.
- Energy System:
    - *Geothermal system for first two new buildings integrated with natural gas*
    - *Capability to expand to complete District Energy System incorporating waste heat from ice rink for both new & existing buildings.*

Hudson Building

- Environmental Benefits
    - Reduced demand on BC's electricity grid
    - Energy Usage in new buildings is reduced by up to 59% & GHGs by up to 73%

Summary

- **Our approach will maximize our growth opportunities and will be a model for thermal utilities of the 21st century**

1. ***Model works for Terasen & British Columbia***
   - **Spurred by aggressive climate change targets & expectations**
   - **Can meet challenge of low cost clean electricity**
   - **Terasen alternative energy segment is established & growing**
   - **Investment opportunity much higher than traditional gas**

2. ***Utility model applied to integrated gas & alternative thermal energy delivery provides numerous benefits***
   - **Recognizes renewable energy future with flexible platform**
   - **Relieves governments of need to fund alternative energy infrastructure**
   - **Enables governments to meet climate change objectives**
   - **Ensures fair & competitive energy costs for end use customers**
   - **Allows transparent & open regulatory process**

Questions?

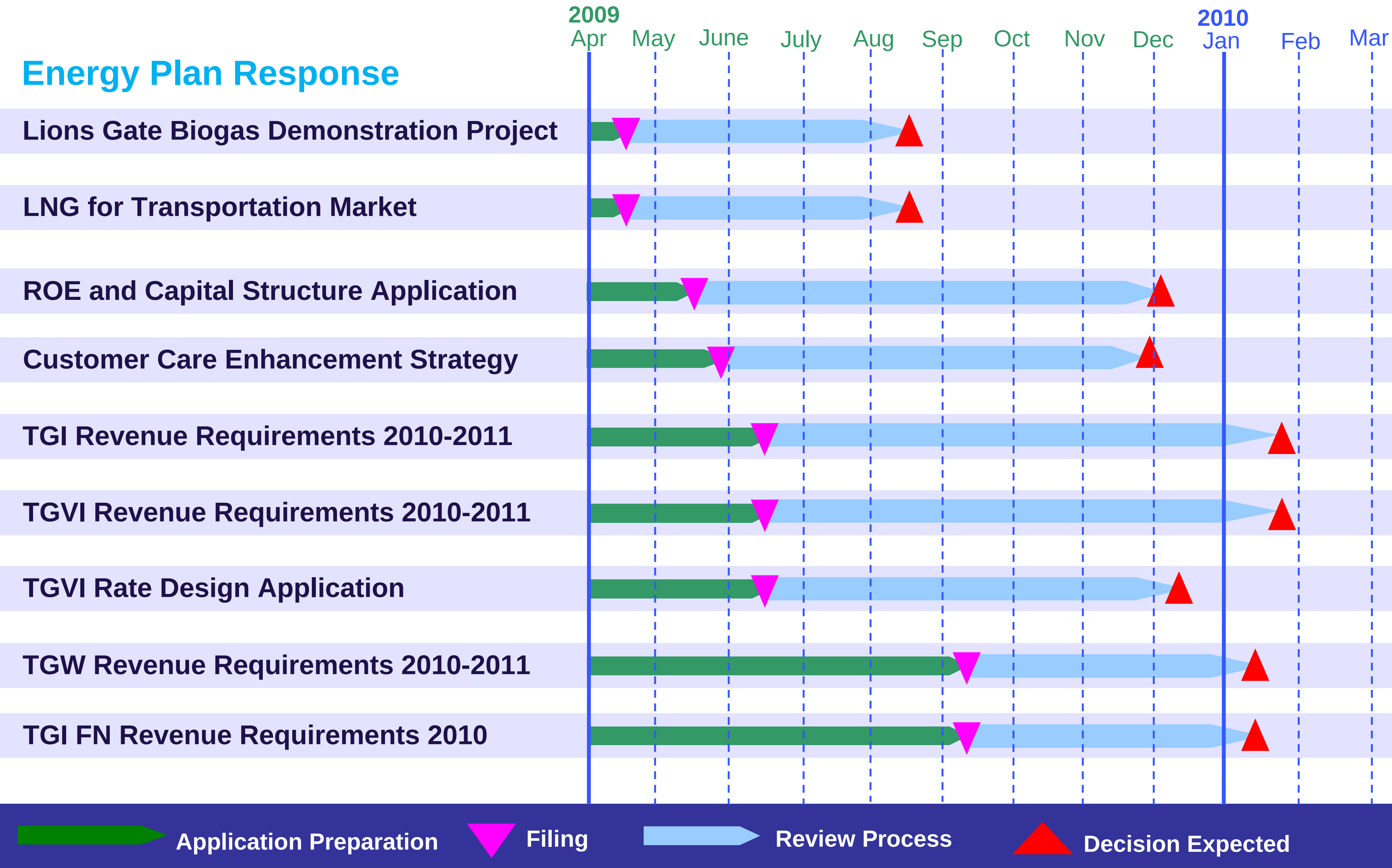
Land Fill
Branding as an Energy Company
NG Delivery
Transportation Natural Gas Vehicles
NG Plant
Pipelines
Local Distribution Company
Energy Centre
Thermal Energy Delivery
Residential Customers
Bio Gas
Waste Heat
Solar
Biomass
Geothermal
Customer Information System and Advanced Metering
Commercial & Industrial Customers
Alternative Energy
Expanded Energy Efficiency and Conservation Activity
Regional Infrastructure
Alternative Energy Supply
Expanded Suite of Products and Services
Enablers

Regulatory Calendar

Scott Thomson, Vice President
Regulatory Affairs & CFO

Anticipated Timing and Process – Major Filings
Regulatory Calendar – 2009 and 2010

Terasen Gas



Status Update of Major Projects

Cynthia Des Brisay, Vice President, Gas Supply & Transmission

Whistler Pipeline and Conversion

- 50 km pipeline extension from Squamish completed and put in service in April 2009
- Conversion commenced on April 29
- Propane System to be decommissioned this fall

Whistler Conversion

- 2,150 Residential & 325 Commercial customers
- 14,500 appliances to be converted
- Conversion team 80+ employees and contractors from across the province

Whistler Conversion

- Service area split in 84 sections and conversion of each section completed once work begins
  - Approximately 20 sections completed to date

Whistler Conversion

Westin Hotel

- Example of large commercial customer
- Boilers, Kitchens, and 367 Fireplaces!
- High degree of co-operation & coordination
- Conversion completed in two days

Mount Hayes Storage Facility

Description

- 1.5 bcf storage facility
- 7.5mmcf/d liquefaction
- 150 mmcf/d send-out
- Capital cost $200M
- Serves both Vancouver Island and the Lower Mainland

Mt Hayes Storage Facility

- Groundbreaking in May 2008
- Liquefaction begins April 2011
- Full Commissioning complete Nov 2011
- Currently on budget and on schedule

Mt Hayes Storage Facility

Mt Hayes Storage Facility

- 80 – 120 workers on site
- 20 HCBI workers, remaining workforce 75% local, 25% rest of BC
- First Nation involvement
- To date $27 million in local subcontracts, employment & services

- First Nation involvement in construction, site and pipeline work and other services

Fraser River South Arm Upgrade

- Replacement of twin pipeline crossings using Horizontal drilling
- Cost estimate $27.3M
- Mitigates seismic, river erosion, and dike improvement concerns
- Improves reliability and security of supply for up to 220,000 customers
- Completion by end of 2010

Fraser River South Arm Upgrade

Attachment 84.6

This short form prospectus has been filed under legislation in all provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities.

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. The securities offered hereby have not been and will not be registered under the U.S. Securities Act of 1933 and may not be offered or sold within the United States. ***Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada.*** *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of Terasen Gas Inc. at Suite 1000, 1111 West Georgia Street, Vancouver, British Columbia, V6E 4M3 (Telephone (604) 443-6526), and are also available at www.sedar.com.*

New Issue **SHORT FORM BASE SHELF PROSPECTUS** **April 24, 2008**

Terasen Gas

TERASEN GAS INC.
$600,000,000
MEDIUM TERM NOTE DEBENTURES
(Unsecured)

Medium Term Note Debentures (the "MTN Debentures") offered hereunder will have maturities of not less than one year and will be either interest bearing MTN Debentures or non-interest bearing MTN Debentures issued at par, at a discount or at a premium. The MTN Debentures may be issued as registered debentures or in the form of fully registered global debentures. The MTN Debentures will be issued at rates of interest or at prices determined by Terasen Gas Inc. ("Terasen Gas" or the "Company") from time to time based on a number of factors, including advice from the Dealers. All references to currency in this short form prospectus are references to Canadian dollars. See "Details of the Offering".

The specific terms of any offering of MTN Debentures (including the aggregate principal amount of MTN Debentures being offered, the currency, the issue and delivery date, the maturity date, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), the interest payment date(s), any redemption or repurchase provisions, the names of the Dealers, the Dealers' commission, the method of distribution and the actual proceeds to the Company) will be set forth in a pricing supplement which will accompany this short form prospectus or any amendments to this short form prospectus. The Company reserves the right to set forth in a pricing supplement specific variable terms of MTN Debentures which are not within the options and parameters set forth in this short form prospectus.

The MTN Debentures will be issued from time to time as and when funds are required by the Company in an aggregate principal amount of up to $600 million (or the equivalent thereof in foreign currencies or currency units) during the 25 month period from the date of this short form prospectus. The MTN Debentures will rank equal in priority to all other unsecured and unsubordinated indebtedness of the Company and will be issued under a trust indenture. As of March 31, 2008 a total of $1,068 million aggregate principal amount of MTN Debentures were issued and outstanding.

There is no market through which these securities may be sold and purchasers may not be able to resell securities purchased under this short form prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities, and the extent of issuer regulation. See "Risk Factors".

Rates on Application

The MTN Debentures may be offered by one or more of BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to the dealer agreement referred to under the heading "Plan of Distribution", or such other investment dealers as may be selected from time to time by the Company (the "Dealers"). The rate of commission payable in connection with sales by the Dealers of MTN Debentures shall be as determined from time to time by mutual agreement and will be set forth in a pricing supplement which will accompany this short form prospectus. The MTN Debentures may be purchased from time to time by any of the Dealers, as principal, at such prices and with such commissions as may be agreed between the Company and any such Dealers for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will be increased or decreased by the amount which the aggregate price paid for MTN Debentures by purchasers exceeds or is less than the gross proceeds paid by the Dealer, acting as principal, to the Company. The MTN Debentures may also be offered directly by the Company from time to time to purchasers pursuant to applicable statutory exemptions.

The MTN Debentures offered hereby have not been and will not be registered under the United States Securities Act of 1933. Accordingly, the MTN Debentures offered hereby may not be offered or sold in the United States of America, and this short form prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of the MTN Debentures offered hereby within the United States. See "Plan of Distribution".

Under applicable securities legislation in Canada, the Company may be considered to be a connected issuer of each of the Dealers, as each is directly or indirectly a wholly-owned or majority-owned subsidiary of a Canadian chartered bank which has extended credit facilities to the Company upon which the Company may draw from time to time. See "Plan of Distribution".

The offering is subject to approval of all legal matters on behalf of the Company by Farris, Vaughan, Wills & Murphy LLP and on behalf of the Dealers by Lawson Lundell LLP.

TABLE OF CONTENTS

FORWARD-LOOKING STATEMENTS

Certain statements contained in this short form prospectus and the documents incorporated herein by reference contain forward-looking information within the meaning of applicable securities laws in Canada ("Forward-looking Information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify Forward-looking Information, although not all Forward-looking Information contains these identifying words.

The Forward-looking Information in this short form prospectus, and the documents incorporated herein by reference, includes, but is not limited to, statements regarding: the Company's expectation to generate sufficient cash from operations to meet its working capital needs and to maintain its financial capacity and flexibility; the Company's expected capital expenditures, including estimated construction costs, and the expectation to finance those expenditures with a combination of proceeds from shareholder advances, short and long term borrowings and internally generated funds; the Company's belief that changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts; the Company's expectation that delivery margins will not be impacted by migration of residential customers to alternative commodity suppliers; and the Company's expectation that compliance with environmental laws and regulations will not have a material effect on the Company's capital expenditures, earnings or competitive position.

The forecasts and projections that make up the Forward-looking Information are based on assumptions, which include but are not limited to receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability as a result of a catastrophic event or environmental upset; the competitiveness of natural gas pricing when compared with alternate sources of energy; continued population growth and new housing starts; the availability of natural gas supply; access to capital; interest rates and the ability to hedge certain risks.

The Forward-looking Information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the Forward-looking Information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk; operational disruptions and environmental risk; price competitiveness risk; changes in economic conditions; natural gas supply risks; capital and credit ratings risk; interest rate risk; counterparty credit risk and changes in tax legislation. For additional information with respect to these risk factors, reference should be made to the sections entitled "Risk Factors" in the annual information form of the Company and "Commitments, Events, Risks and Uncertainties" in the management's discussion and analysis relating to the audited annual financial statements of the Company incorporated by reference herein.

All Forward-looking Information in this short form prospectus and the documents incorporated herein by reference relates only to events or information as of the date on which the statements are made and is qualified in its entirety by this cautionary statement. Except as required by law, the Company undertakes no obligation to revise or update any Forward-looking Information as a result of new information, future events or otherwise after the date hereof.

This short form prospectus and the documents incorporated herein by reference should be read completely and with the understanding that the Company's future results may be materially different from what the Company expects.

DOCUMENTS INCORPORATED BY REFERENCE

The following documents filed with the securities commissions or similar authorities in each of the provinces of Canada are specifically incorporated by reference into and form an integral part of this short form prospectus:

(a) the annual information form of the Company dated April 17, 2008; and

(b) the audited consolidated financial statements of the Company for the year ended December 31, 2007, together with the auditors' report thereon and the management's discussion and analysis filed in connection with such audited financial statements and the audited consolidated financial statements of the Company for the year ended December 31, 2006, together with the auditors' report thereon.

Any document of the type referred to in the preceding paragraph, any interim financial statements together with management's discussion and analysis filed in connection with such interim financial statements, any business acquisition reports, information circulars, and any material change reports (excluding confidential reports) as well as any prospectus supplements disclosing additional or updated information filed with a provincial securities commission or any similar authority in Canada, after the date of this short form prospectus and prior to the termination of the offering, shall be deemed to be incorporated by reference into this short form prospectus.

A pricing supplement or other prospectus supplement containing the specific variable terms of an offering of MTN Debentures will be delivered to purchasers of such MTN Debentures together with this short form prospectus and will be deemed to be incorporated by reference into this short form prospectus as of the date of such supplement and only for the purposes of the offering of the MTN Debentures covered by that supplement.

Upon a new annual information form and the related audited consolidated financial statements being filed by the Company with and, where required, accepted by the applicable securities regulatory authorities during the currency of this short form prospectus, the previous annual information form, the previous audited consolidated financial statements, all interim unaudited consolidated financial statements, business acquisition reports, material change reports and information circulars filed prior to the commencement of the Company's financial year in which the new annual information form was filed shall be deemed no longer to be incorporated into this short form prospectus for purposes of future offers and sales of securities hereunder.

Any statement contained herein or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of this short form prospectus to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such statement. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not constitute a part of this short form prospectus, except as so modified or superseded.

THE COMPANY

The Company was formed by the amalgamation on July 1, 1989 under the *Company Act* (British Columbia), a predecessor to the *Business Corporations Act* (British Columbia), of Inland Natural Gas Co. Ltd., B.C. Gas Inc., Columbia Natural Gas Limited and Fort Nelson Gas Ltd. On July 1, 1993 pursuant to an arrangement between the Company and a subsidiary, the Company changed its name to "BC Gas Utility Ltd.". Effective April 25, 2003, the Company changed its name to "Terasen Gas Inc.". The Company amalgamated with its subsidiary Terasen Gas (Squamish) Inc. on January 1, 2007. The head office and registered office of the Company is located at Suite 1000, 1111 West Georgia Street, Vancouver, British Columbia, V6E 4M3. The "Company" or "Terasen Gas" includes its subsidiary companies, as the context so requires. The Company is a wholly-owned subsidiary of Terasen Inc. ("Terasen"). Terasen is a wholly-owned subsidiary of Fortis Inc.

The Company transmits and distributes natural gas to residential, commercial and industrial customers in the interior and in the Greater Vancouver and Fraser Valley areas of British Columbia.

The Company owns 100% of the shares of Inland Energy Corp., which holds purchase money mortgages of the Company pending their securitization.

USE OF PROCEEDS

The MTN Debentures will be issued from time to time at the discretion of the Company in an aggregate principal amount of up to \$600 million during the 25 month period from the date of this short form prospectus. The net proceeds to be derived from the issue of the MTN Debentures offered hereunder will be the issue price thereof less any commission paid in connection therewith. Such net proceeds cannot be estimated as the amount thereof will depend on the extent to which MTN Debentures are issued hereunder. Unless otherwise specified in the pricing supplement which accompanies this short form prospectus, such net proceeds will be added to the general funds of the Company and may be used to refinance existing indebtedness or to reduce short term indebtedness which may be outstanding from time to time. Although no proceeds have been specifically allocated for such purpose, at a future point in time proceeds may be used to reduce indebtedness under the Company's credit facilities with its bankers. The expenses of this offering and commissions will be paid out of the Company's general funds.

EARNINGS COVERAGE

The earnings coverage set forth below is based on consolidated financial information as at and for the year ended December 31, 2007. It does not give effect to the issue of MTN Debentures pursuant to this short form prospectus, since the aggregate principal amount of MTN Debentures that will be issued hereunder and the terms of issue are not presently known.

The Company's interest requirements on consolidated long term debt amounted to \$99.7 million for the year ended December 31, 2007 adjusted to reflect the issuance and repayment of long term debt after such date. The Company's consolidated earnings before interest on long term debt and income taxes were \$216.0 million for the year ended December 31, 2007, which is 2.17 times the Company's interest requirements on consolidated long term debt for the year then ended.

	December 31, 2007
Earnings coverage on long term debt...	2.17 times

CREDIT RATINGS

The Company has received an A3 rating from Moody's Investors Service ("Moody's") and an A rating from DBRS Limited ("DBRS") in respect of its outstanding MTN Debentures including the MTN Debentures which may be issued pursuant to this prospectus. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. DBRS rates debt instruments by rating categories ranging from AAA which represents the highest quality of securities, to D, which represents the lowest quality of securities rated. Moody's rates debt instruments by rating categories ranging from Aaa which represents the highest quality of securities, to C, which represents the lowest quality of securities.

According to the Moody's rating system, debt securities rated A are considered to be upper medium grade obligations and are subject to very low credit risk. Moody's applies numerical modifiers (1, 2 and 3) in each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its rating category.

According to the DBRS rating system, debt securities rated A are of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than that of AA related entities. While a respectable rating, entities in the A category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher rated companies. "High" or "low" are used to indicate the relative standing of a credit within a particular rating category. The lack of one of these designations indicates a rating which is essentially in the middle of the category.

After reassessing its relationship with Standard and Poor's Rating Services, a division of the McGraw-Hill Companies ("S&P"), the Company discontinued the engagement of S&P to provide credit ratings in respect of the MTN Debentures. S&P continues to rate the Company's medium term note debenture program on the basis of publicly-available information. S&P has assigned a rating of A to the Company's medium term note program.

S&P rates debt instruments by rating categories ranging from AAA which represents the highest quality of securities, to D which represents the lowest quality of securities rated. According to the S&P rating system, debt securities rated A are somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories. However, the obligor's capacity to meet its financial commitment on the obligation is still strong. A plus (+) or minus (-) description after a rating shows the relative standing within the major rating categories (AA to CCC). The lack of one of these designations indicates a rating which is essentially in the middle of the category.

The credit ratings accorded to the MTN Debentures are not recommendations to buy, sell or hold the MTN Debentures inasmuch as those ratings do not comment as to market price or suitability for a particular investor. There is no assurance that these ratings will remain in effect for any given period of time. These ratings may be subject to revision or withdrawal at any time by the rating agencies.

DETAILS OF THE OFFERING

MTN Debentures issued hereunder will have maturities of not less than one year and will either be interest bearing MTN Debentures or non-interest bearing MTN Debentures issued at par, at a discount or at a premium. The MTN Debentures may be issued in Canadian dollars, or any other currency as determined at the time of issue. The MTN Debentures are issuable in minimum denominations of $5,000 and multiples of $1,000 thereafter, and if issued in any other currency in such denominations in such other currency as may be determined from time to time. The MTN Debentures will be issued as and when funds are required by the Company. The aggregate principal amount of MTN Debentures to be offered hereunder will not exceed $600 million. As at March 31, 2008 a total of $1,068 million aggregate principal amount of MTN Debentures were issued and outstanding.

All references to currency in this short form prospectus are references to Canadian dollars. For MTN Debentures issued in other than Canadian currency, potential purchasers should be aware that foreign exchange fluctuations will occur from time to time and that neither the Company nor the Dealers make any representation with respect to currency values from time to time.

MTN Debentures may be issued as registered debentures or in the form of fully registered global debentures (“Global Debentures”) held by CDS Clearing and Depository Services Inc. or a successor (the “Depositary”) for its participants. CIBC Mellon Trust Company or a successor will act as the transfer agent and registrar of the MTN Debentures. The Depositary establishes and maintains book entry accounts for its participants having interests in Global Debentures. The interests of participants of the Depositary in Global Debentures, and transfers of interests in the Global Debentures between participants, will be effected by entries made in the records maintained by the Depositary. The interests of customers of participants in the MTN Debentures will be effected by entries made in the records maintained by the participants. Purchasers of MTN Debentures in respect of which Global Debentures are issued will not be entitled to receive MTN Debentures in definitive form except in certain stated events, including upon the request of holders of not less than 10% of the principal amount of outstanding MTN Debentures upon the happening of any event of default. The issuance of MTN Debentures as Global Debentures will, if applicable, be referred to in the relevant pricing supplement delivered with this short form prospectus.

The specific variable terms of any offering of MTN Debentures, including the aggregate principal amount of MTN Debentures being offered, the currency, the issue and delivery date, the maturity date, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), the interest payment date(s), any redemption or repurchase provisions, the names of the Dealers, the Dealers’ commission, the method of distribution and the actual proceeds to the Company, will be set forth in a pricing supplement which will accompany this short form prospectus or any amendments to this short form prospectus. The Company reserves the right to set forth in a pricing supplement specific variable terms of the MTN Debentures which are not within the options and parameters set forth in this short form prospectus.

The registered holder of a MTN Debenture may transfer such MTN Debenture upon payment of taxes incidental thereto, if any, by executing and delivering a form of transfer together with the MTN Debenture to the Trustee at its principal corporate trust office in any of the cities of Vancouver, Toronto or Montreal upon which one or more new MTN Debentures will be issued in authorized denominations in the same aggregate principal amount as the MTN Debenture so transferred, registered in the name or names of the transferee or transferees. No transfer of a MTN Debenture will be registered during the seven business days (a business day for this purpose being a business day in the city of Vancouver) immediately preceding any date fixed for payment of interest on such MTN Debenture.

The following summary of certain provisions of the Indenture (as defined below) and the MTN Debentures does not purport to be complete and is subject to the detailed provisions of the Indenture to which reference is hereby made for a full description of such provisions, including the definition of certain terms used herein, and for other information regarding the MTN Debentures.

General

The MTN Debentures will be issued under a trust indenture dated as of November 1, 1977 made between the Company (as successor to Inland Natural Gas Co. Ltd.) and CIBC Mellon Trust Company (formerly called The R-M Trust Company, as successor to National Trust Company, Limited), as trustee (the “Trustee”), as supplemented and amended by a first supplemental indenture dated as of November 17, 1981, a second supplemental indenture dated as of July 11, 1984, a third supplemental indenture dated as of December 17, 1986, a fourth supplemental indenture dated as of June 1, 1989, a fifth supplemental indenture dated as of July 1, 1989, a sixth supplemental indenture dated as of June 14, 1990, a seventh supplemental indenture dated as of October 26, 1990, an eighth supplemental indenture dated as of August 1, 1992, a ninth supplemental indenture dated as of July 28, 1993, a tenth supplemental indenture dated as of November 15, 1993 (the "MTN Supplemental Indenture") and an eleventh supplemental indenture dated as of January 1, 2007 (the trust indenture, as so supplemented and amended from time to time, being herein called the "Indenture"). The Indenture will be available for review during normal business hours during the period of distribution of the MTN Debentures at the head office of the Company at Suite 1000, 1111 West Georgia Street, Vancouver, British Columbia.

The aggregate principal amount of debentures authorized under the Indenture (the "Debentures") is unlimited. Debentures may be issued thereunder in one or more series. The MTN Debentures are a series of Debentures authorized by the MTN Supplemental Indenture in an unlimited amount, and may be issued on such terms and at such times as may be determined by the Company, subject to the Company meeting certain tests with respect to the issue thereof, as set forth in the Indenture.

The MTN Debentures will rank in equal priority with all other unsecured and unsubordinated indebtedness of the Company. As at March 31, 2008, there was approximately $59.9 million aggregate principal amount of Debentures outstanding under the Indenture, other than MTN Debentures. The MTN Debentures will rank junior to any outstanding First Mortgage Bonds issued under a trust deed and secured by substantially all of the Company's assets and the Purchase Money Mortgages which are secured under a trust deed over the assets of the Company acquired as part of its acquisition of the coastal gas distribution assets of British Columbia Hydro and Power Authority (the "Coastal Division") in 1988. Currently there are no First Mortgage Bonds outstanding. There are $274.9 million principal amount of Purchase Money Mortgages presently held by the public and $150 million presently held by a subsidiary of the Company pending securitization. The Purchase Money Mortgages were issued to finance the Company's acquisition of the Coastal Division.

Payments of interest on each interest-bearing MTN Debenture will be made by electronic funds transfer, if agreed to by the purchasers, or by cheque dated the interest payment date and mailed to the address of the holder appearing on the registers maintained by the Trustee at the close of business on the seventh business day (a business day for this purpose being a business day in the city of Vancouver) prior to the due date for the payment of interest. Payment of principal at maturity will be made at the principal corporate trust office of the Trustee in the cities of Vancouver, Toronto or Montreal against surrender of the MTN Debenture. If the due date for payment of any amount of principal or interest on any MTN Debenture is not, at the place of payment, a business day (being a day other than Saturday, Sunday, or a day on which financial institutions at the place of payment are authorized or obligated by law or regulation to close) such payment will be made on the next business day and the holder of such MTN Debenture shall not be entitled to any further interest or other payment in respect of such delay.

The payment of principal and interest on a MTN Debenture in accordance with the indenture shall absolutely satisfy and discharge the liability of the Company with respect to such payment under the MTN Debenture, unless in the case of payment by cheque it is not paid upon presentation.

Events of Default

Except as otherwise noted below, the Indenture provides that the following constitute events of default (each an "Event of Default") thereunder:

(a) default in payment of principal of any Debenture when due;

(b) default in payment of any interest due on any Debenture and such default has continued for 30 days;

(c) an order is made or an effective resolution passed for the winding-up or liquidation of the Company (other than pursuant to and in compliance with provisions in the Indenture relating to successor companies);

(d) the Company or any Designated Subsidiary (as defined below) makes a general assignment for the benefit of its creditors, is declared bankrupt, a sequestrator or a receiver or any other officer with similar powers is appointed of, or an encumbrancer takes possession of, the property of the Company or of the property of a Designated Subsidiary, or any substantial part thereof;

(e) any process of execution is enforced or levied upon any property of the Company or a Designated Subsidiary and remains unsatisfied for a period of 30 days, as to moveable or personal property, or 45 days, as to immovable or real property, provided that such process is not in good faith disputed by the Company or such Designated Subsidiary or the Company or such Designated Subsidiary has given adequate security;

(f) default under the mortgage with respect to the First Mortgage Bonds which causes the principal amount of the First Mortgage Bonds to be declared immediately due and payable, provided that if the default is cured and such declaration is rescinded the Event of Default will also be cured; and

(g) the Company neglects to carry out or observe any covenant or condition contained in the Indenture and, after notice has been given by the Trustee to the Company, the Company fails to make good such default within 60 days or such shorter period as would at any time, if continued, render any property of the Company or any of its subsidiaries liable to forfeiture, unless the Trustee has agreed to a longer period, and in such an event, within the period agreed to by the Trustee.

Acceleration on and Waiver of Default

If an Event of Default has occurred under the Indenture, the Trustee may in its discretion and will upon the requisition in writing of the holders of at least 25% of the principal amount of the Debentures issued and outstanding under the Indenture, subject to any waiver of default under the Indenture, by notice in writing to the Company declare the principal and interest on all Debentures then outstanding under the Indenture and other money payable thereunder to be due and payable.

If an Event of Default has occurred under the Indenture (otherwise than by default in payment of principal moneys at maturity) the holders of the Debentures have the power by extraordinary resolution to instruct the Trustee to waive the default (provided that if the Event of Default relates to a covenant applicable to a particular series of Debentures only, then the holders of outstanding Debentures of that series only have the power by extraordinary resolution to instruct the Trustee to waive the default). In addition, the Trustee, so long as it has not become bound to institute any proceedings under the Indenture, has power to waive the default if, in the Trustee's opinion, the same shall have been cured or adequate satisfaction made therefor.

In the Indenture, "extraordinary resolution" is a resolution passed at a meeting of debentureholders by the favourable votes of the holders of not less than 66⅔% of the principal amount of Debentures represented at the meeting.

Right of Trustee to Enforce Payment

If the Company fails to pay to the Trustee, on demand, and when due, the principal and interest on all Debentures then outstanding under the Indenture, the Trustee may, in its discretion, and shall upon the request in writing of the holders of not less than 25% of the principal amount of the Debentures issued and outstanding under the Indenture, and upon being indemnified to its reasonable satisfaction against all costs, expenses and liabilities to be incurred, proceed in its name as Trustee to obtain or enforce payment of the principal and interest on all outstanding Debentures together with other amounts due under the Indenture by any remedy or proceeding authorized by the Indenture.

Holders of Debentures issued under the Indenture may not institute any action or proceeding or exercise any other remedy authorized by the Indenture, including an action to enforce the Indenture or the Debentures, except as provided in the Indenture.

Covenants

The Indenture contains, among others, covenants substantially to the following effect:

(a) The Company will not mortgage, pledge, charge or otherwise encumber any of its assets to secure any obligations unless at the same time it shall, in the opinion of counsel, secure or cause to be secured equally and rateably with such obligations all the Debentures then outstanding under the Indenture by the same instrument or by other instrument in form and substance satisfactory to such counsel; provided that this covenant shall not apply to (a) First Mortgage Bonds, (b) Purchase Money Mortgages, (c) permitted encumbrances as defined in the Indenture, or (d) security given (other than on fixed assets) in the ordinary course of business and for the purpose of carrying on the same, to any bank or banks or others to secure any indebtedness other than Funded Obligations.

(b) The Company will not permit any Designated Subsidiary to create, incur or guarantee any indebtedness, except indebtedness to or of the Company or to a trustee in support of a guarantee of indebtedness of the Company, provided that this shall not apply to (a) Purchase Money Mortgages, or (b) indebtedness incurred in the ordinary course of business and for the purpose of carrying on the same, to any bank or banks or others, repayable on demand or maturing, including any right of extension or renewal, within 18 months of the date when such indebtedness is incurred, provided such indebtedness is not secured on fixed assets.

(c) The Company or a Designated Subsidiary will not dispose of any indebtedness of a Designated Subsidiary unless all the shares and indebtedness of such Designated Subsidiary are sold to a party dealing with the seller at arm's length, resulting in neither the Company nor any other Designated Subsidiary owning any of such Designated Subsidiary.

(d) The Company will not permit any Designated Subsidiary to issue any shares if, as a result of such issue, such Designated Subsidiary ceases to qualify as such.

(e) The Company will not create or issue any Additional Obligations unless Consolidated Available Net Earnings for any period of 12 consecutive calendar months of the 23 calendar months next preceding the date of issue of such Additional Obligations, which period shall have been selected by the Company, shall have been at least two times the annual interest requirements of all Funded Obligations to be outstanding after the issue of such Additional Obligations and after any retirements of Funded Obligations to be made out of the proceeds thereof or retirement thereof has been otherwise provided for and in respect of which proof has been afforded to the Trustee satisfactory to it that adequate provision has been made assuring that such Funded Obligations will be retired within 45 days after the issue of such Additional Obligations; provided the provisions of this covenant shall not apply to the creation and issue of Additional Obligations for the purpose of refunding the whole of any series of Debentures previously issued under the Indenture provided that (except in the case of refunding all of the MTN Debentures) the aggregate principal amount of the Additional Obligations does not exceed the aggregate principal amount of the Debentures to be refunded.

(f) The Company will, directly or through Designated Subsidiaries, from time to time obtain and at all times maintain facilities for supplies of gas adequate to enable the carrying on of its business.

Modification

The rights of the holders of the MTN Debentures under the Indenture may be modified. For that purpose, among others, the Indenture will contain provisions making binding upon all holders of Debentures outstanding under the Indenture and indentures supplemental thereto, resolutions passed at meetings of debentureholders by the favourable votes of the holders of not less than 66⅔% of the principal amount of Debentures voted on the resolution or instruments in writing signed by the holders of not less than 66⅔% of the principal amount of all the outstanding Debentures. In certain cases, modification will require separate assent by the holders of the required percentages of debentures of each series outstanding under the Indenture or any series of MTN Debentures outstanding under the Indenture as determined by the Trustee.

Definitions

The Indenture contains definitions substantially to the following effect:

"*Additional Obligations*" means bonds, debentures, notes or other debt instruments issued by the Company, the due date of payment of which, including any right of extension or renewal, is 18 months or more after the date of issue but does not include First Mortgage Bonds and Purchase Money Mortgages.

"*Consolidated Available Net Earnings*" for any specified period of 12 months means the net earnings of the Company and its Designated Subsidiaries on a consolidated basis for such period (excluding gains or losses on the disposal of investments or fixed assets in each case in excess of $50,000 in the aggregate and other non-recurring items in excess of $50,000 in the aggregate) before deductions for income taxes, interest on Funded Obligations and on any other indebtedness that since the end of the specified period has been or is about to be refunded by the issue of Funded Obligations and amortization of debt premium, discount and expense, all as determined in accordance with generally accepted accounting principles and reported on by the Company's auditors without, in their opinion, material adverse qualification. In determining Consolidated Available Net Earnings for any period there shall be taken into account the earnings or losses, as the case may be, for the whole of such period of any company or corporation which, prior to or concurrently with the proposed action in respect of which such determination is being made, becomes a Designated Subsidiary. In addition, if the Company or any Designated Subsidiary shall, prior to or concurrently with the proposed action in respect of which such determination is being made, have acquired any business by way of acquisition of assets, the earnings or losses, as the case may be, of such business to the extent that such earnings or losses related to the assets acquired, shall be taken into account for the whole of such period.

"*Designated Subsidiary*" means any company or corporation the majority of the outstanding shares of each class of the capital stock of which having attached to them voting rights under all circumstances are owned by the Company and/or one or more Designated Subsidiaries, provided that the Company shall have, by resolution of its directors, designated such other company or corporation as a Designated Subsidiary; provided that any Designated Subsidiary shall cease to be a Designated Subsidiary upon sale of all its shares and indebtedness owned by the Company and any other Designated Subsidiary, resulting in neither the Company nor any other Designated Subsidiary owning any of such Designated Subsidiary.

"*First Mortgage Bonds*" means all first mortgage bonds or other first mortgage obligations of the Company, whether heretofore or hereafter issued, secured by a first fixed and specific charge on substantially all the fixed assets of the Company (whether or not also secured by a floating charge or by other security).

"*Funded Obligations*" means any indebtedness, whether secured or unsecured, incurred by any one or more of the Company and the Designated Subsidiaries by way of creation, guarantee, assumption or otherwise which is not repayable on demand and the due date of payment of which, including any right of extension or renewal, is 18 months or more after the date on which it was incurred, but does not include (i) indebtedness secured by Purchase Money Mortgages and (ii) any liability in respect of any guarantee by any one or more of the Company and the Designated Subsidiaries of the indebtedness of the Company and/or any Designated Subsidiaries secured by Purchase Money Mortgages.

"*Purchase Money Mortgages*" means any mortgages, liens or other encumbrances upon property acquired by one or more of the Company and the Designated Subsidiaries which were, at the time of such acquisition or concurrently therewith, assumed, created or given to secure all or part of the cost of such property and extensions and renewals thereof upon the same property if the principal amount of the indebtedness secured thereby is not increased.

RISK FACTORS

Prospective investors in a particular offering of MTN Debentures should consider, in addition to the matters described under the heading "Risk Factors" in the annual information form of the Company and the matters described under the heading "Commitments, Events, Risks and Uncertainties" in the management's discussion and analysis relating to the annual audited financial statements that are incorporated by reference herein, the following risk factors.

Credit Ratings

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the MTN Debentures are not a recommendation to buy, sell or hold the MTN Debentures, because ratings do not comment as to market price or suitability for a particular investor. There is no assurance that these ratings will remain in effect for any given period of time. These ratings may be subject to revision or withdrawal at any time by the relevant rating agency. Real or anticipated changes in credit ratings on the MTN Debentures may affect the market value of the MTN Debentures. In addition, real or anticipated changes in credit ratings can affect the cost at which the Company can access the debt market.

Lack of Public Market for MTN Debentures

This short form prospectus qualifies new issues of debt securities for which there is no existing trading market. The Company does not intend to list the MTN Debentures on any securities exchange or to arrange for any quotation system to quote them and consequently the Company will not be subject to regulation by any securities exchange or quotation system. There can be no assurance as to the liquidity of any trading market for the MTN Debentures or that a trading market for any of the MTN Debentures will develop. Even if a trading market develops in the MTN Debentures, the MTN Debentures could trade at prices that may be higher or lower than their initial offering prices and there may be limited transparency of trading prices. The market price for the MTN Debentures may be affected by prevailing interest rates, the Company's results of operations and financial position, the ratings assigned to the MTN Debentures or the Company, changes in general market conditions, fluctuations in the market for equity or debt securities and numerous other factors beyond the control of the Company.

PLAN OF DISTRIBUTION

The MTN Debentures may be offered for sale by any one or more of BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to a dealer agreement dated April 24, 2008 among such investment dealers and the Company (the "Dealer Agreement"), or by other investment dealers selected from time to time by the Company (the "Investment Dealers"). The rate of commission payable in connection with sales by the Investment Dealers of MTN Debentures shall be as determined from time to time by mutual agreement. The MTN Debentures may be purchased from time to time by any of the Investment Dealers, as principal, at such prices and with such commissions as may be agreed between the Company and any such Investment Dealers for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Investment Dealer's compensation will be increased or decreased by the amount by which the aggregate price paid for MTN Debentures by purchasers exceeds or is less than the gross proceeds paid by that Investment Dealer, acting as principal, to the Company. The Dealer Agreement also provides that in the event an Investment Dealer is purchasing MTN Debentures as principal, the obligation of that Investment Dealer to purchase as principal may be terminated in certain stated events. The MTN Debentures may also be offered directly by the Company at market rates prevailing from time to time to purchasers pursuant to applicable statutory exemptions and may from time to time be offered at a discount or a premium.

The MTN Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). The MTN Debentures may not be offered, sold or delivered within the United States, except in certain transactions exempt from the registration requirements of the U.S. Securities Act. Each Dealer has agreed that it will not offer, sell or deliver any MTN Debentures within the United States. In addition, until 40 days after the commencement of the offering, an offer or sale of any MTN Debentures within the United States by any dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act.

Under applicable securities legislation in Canada, the Company may be considered to be a connected issuer of each of the Dealers, as each is directly or indirectly a wholly-owned or majority-owned subsidiary of a Canadian chartered bank (collectively, the "Banks") which has extended credit facilities to the Company upon which the Company may draw from time to time. The Company's credit facilities with the Banks consist of a $500 million syndicated 5-year revolving credit facility. As at March 31, 2008, $43.9 million of the available credit under this facility has been utilized. This credit facility is unsecured and the Company is, and has been since the establishment of the credit facility, in compliance with the terms of the agreement governing the credit facility. The Company's financial position has not changed substantially since the credit facility was put in place. The credit facility is available for general corporate purposes, including acquisitions and capital expenditures and to act as a back-up for the Company's commercial paper program. Net proceeds received pursuant to offerings of MTN Debentures may be used, directly or indirectly, to reduce indebtedness of the Company under the credit facility. None of the Banks was involved in the decision to offer the MTN Debentures and none will be involved in the determination of the terms of the distribution of the MTN Debentures. As a consequence of the sale of the MTN Debentures through any Dealer from time to time under this short form prospectus, the Company will pay a commission to each Dealer through which an MTN Debenture is sold.

TRANSFER AGENT AND REGISTRAR

Registers for the registration and transfer of the MTN Debentures will be kept at the principal corporate trust offices of CIBC Mellon Trust Company in the cities of Vancouver, Toronto and Montreal.

ELIGIBILITY FOR INVESTMENT

In the opinion of Farris, Vaughan, Wills & Murphy LLP, counsel to the Company, and Lawson Lundell LLP, counsel to the Dealers, the MTN Debentures offered hereby, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) and the regulations thereunder for trusts governed by registered retirement savings plans, registered retirement income funds, registered education savings plans and deferred profit sharing plans (other than a trust governed by a deferred profit sharing plan in respect of which any employer is the Company or is a person that does not deal at arm's length with the Company within the meaning of the *Income Tax Act* (Canada)).

INTERESTS OF EXPERTS

The matters referred to under "Eligibility for Investment" and certain other legal matters will be passed upon on the Company's behalf by Farris, Vaughan, Wills & Murphy LLP and on behalf of the Dealers by Lawson Lundell LLP. As of the date hereof, the partners and associates of each of Farris, Vaughan, Wills & Murphy LLP and Lawson Lundell LLP beneficially own, directly or indirectly, less than 1% of any securities of the Company.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

AUDITORS' CONSENT

The Board of Directors of Terasen Gas Inc.

We have read the short form base shelf prospectus of Terasen Gas Inc. (the "Company") dated April 24, 2008 relating to the offering of $600,000,000 Medium Term Note Debentures (Unsecured) of the Company. We have complied with Canadian generally accepted standards for an auditors' involvement with offering documents.

We consent to the incorporation by reference in the above mentioned prospectus of our report to the shareholders of the Company on the consolidated statements of financial position of the Company as at December 31, 2007 and the consolidated statements of earnings and comprehensive earnings, retained earnings and cash flows for the year then ended. Our report is dated February 1, 2008.

(Signed) Ernst & Young LLP

Chartered Accountants
Vancouver, Canada
April 24, 2008

AUDITORS' CONSENT

We have read the short form base shelf prospectus dated April 24, 2008 relating to the offering of $600,000,000 Medium Term Note Debentures (Unsecured) of Terasen Gas Inc. (the "Company"). We have complied with Canadian generally accepted standards for an auditors' involvement with offering documents.

We consent to the incorporation by reference in the above mentioned prospectus of our report to the shareholders of the Company on the consolidated statements of financial position of the Company as at December 31, 2006 and the consolidated statements of earnings, retained earnings and cash flows for the year then ended. Our report is dated March 29, 2007.

(Signed) PricewaterhouseCoopers LLP

Chartered Accountants
Vancouver, Canada
April 24, 2008

CERTIFICATE OF TERASEN GAS INC.

Dated: April 24, 2008

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of each of the provinces of Canada.

(Signed) Randall L. Jespersen
President and Chief Executive Officer

(Signed) Scott A. Thomson
Vice President, Regulatory Affairs and
Chief Financial Officer

On behalf of the Board of Directors

(Signed) H. Stanley Marshall
Director

(Signed) Harold Calla
Director

CERTIFICATE OF THE DEALERS

Dated: April 24, 2008

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this prospectus by reference will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of each of the provinces of Canada.

BMO NESBITT BURNS INC.	**CIBC WORLD MARKETS INC.**
By: (Signed) Graeme N. Falkowsky	By: (Signed) Alan C. Wallace
NATIONAL BANK FINANCIAL INC.	**RBC DOMINION SECURITIES INC.**
By: (Signed) Paul Prendergast	By: (Signed) David Dal Bello
SCOTIA CAPITAL INC.	**TD SECURITIES INC.**
By: (Signed) Murray W. Neal	By: (Signed) Edward J. McGurk

This pricing supplement, together with the prospectus to which it relates, as amended or supplemented, and each document deemed to be incorporated by reference into the prospectus, as amended or supplemented, constitutes a public offering of these securities only in the jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Pricing Supplement No. 2 dated February 19, 2009
(To a Prospectus dated April 24, 2008)

Terasen Gas

Terasen Gas Inc.

Medium Term Note Debentures, Series 24
(Unsecured)

Amount and Currency of Issue:	C$100,000,000
Issue and Delivery Date:	February 24, 2009
Issue Price:	$99.635 per $100 principal amount
Commission:	0.50%
Net Proceeds to the Company:	C$99,135,000
Maturity Date:	February 24, 2039
Type of Note:	Global Debenture
Interest Rate:	6.55% per annum, payable semi-annually in arrears
Interest Payment Date(s):	February 24 and August 24
Initial Interest Payment Date:	August 24, 2009
Initial Interest Payment Amount:	$3.275 per $100 principal amount
Redemption Provisions:	The Medium Term Note Debentures, Series 24 issued hereunder will be redeemable, at the Company's option, in whole at any time or in part from time to time on not more than 60 and not less than 30 days' prior notice, at the higher of the Canada Yield Price (as defined below) and par, together with accrued and unpaid interest to the date fixed for redemption.
CUSIP Number:	CA88078Z AH79
Depository:	CDS Clearing and Depository Services Inc.
Trustee/Registrar/Paying Agent:	CIBC Mellon Trust Company
Selling Agent(s):	Scotia Capital Inc. BMO Nesbitt Burns Inc. CIBC World Markets Inc. National Bank Financial Inc. RBC Dominion Securities Inc. TD Securities Inc.

Documents Incorporated by Reference

The following documents (which are not specifically listed in the Prospectus or any amendment or supplement delivered herewith) which have been filed by the Company with the various securities commissions in each of the provinces of Canada are specifically incorporated by reference in and form an integral part of the Prospectus as amended or supplemented:

(a) the audited consolidated financial statements of the Company for the year ended December 31, 2008 which include comparative financial statements for the corresponding period in 2007, together with the auditors' report thereon and the management's discussion and analysis filed in connection with such audited consolidated financial statements; and

(b) the annual information form of the Company dated February 18, 2009.

Definitions

"Canada Yield Price" shall mean a price calculated to provide a yield over the remaining term to maturity of the Medium Term Note Debentures, Series 24 issued hereunder, compounded semi-annually and calculated in accordance with generally accepted financial practice, equal to the Government of Canada Yield plus 0.71% on the business day preceding the date of the resolution authorizing the redemption.

"Government of Canada Yield" on any date shall mean the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted financial practice, which a non-callable Government of Canada Bond would carry if issued in Canadian dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to the remaining term to maturity of the Medium Term Note Debentures, Series 24 issued hereunder. The Government of Canada Yield, in the case of a redemption of the Medium Term Note Debentures, Series 24 issued hereunder, will be the average of the yields provided by two Canadian investment dealers selected by the Company and approved by the Trustee.

Terasen Gas Inc.

Earnings Coverage Ratio
as at March 31, 2009
and December 31, 2008

Pursuant to Section 8.4 of National Instrument 44-102, this updated calculation of the earnings coverage ratio is filed as an exhibit to the unaudited financial statements of Terasen Gas Inc. for the twelve months ended March 31, 2009, in conjunction with a base shelf prospectus dated April 24, 2008.

Earnings Coverage Ratio

The Company's interest requirements on consolidated long term debt amounted to $108.4 million for the twelve months ended December 31, 2008 and $108.3 million for the same period ended March 31, 2009, in each case adjusted to reflect the issuance and repayment of long term debt after the respective date. The Company's consolidated earnings before interest on long-term debt and income taxes were $201.3 million for the twelve months ended December 31, 2008, which is 1.86 times the Company's interest requirements on consolidated long term debt for the period then ended, and $199.4 million for the twelve months ended March 31, 2009, which is 1.84 times the Company's interest requirements on consolidated long term debt for the period then ended.

	December 31, 2008	March 31, 2009
Earnings coverage on long term debt	1.86 times	1.84 times

Attachment 84.7

Terasen Gas Inc.

A subsidiary of Fortis Inc.

2008 Management's Discussion and Analysis

For the Year Ended December 31, 2008

February 6, 2009

This discussion should be read in conjunction with the consolidated financial statements of the Company and related notes for the years ended December 31, 2008 and 2007. In this MD&A, we, us, our, the Company and Terasen Gas mean Terasen Gas Inc., Terasen refers to Terasen Inc., KMI refers to Knight Inc. (formerly known as Kinder Morgan, Inc.) and Fortis refers to Fortis Inc.

The financial data included in this discussion has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), and all dollar amounts are in Canadian dollars unless otherwise stated.

FORWARD LOOKING STATEMENT

Certain statements contained in this Management Discussion & Analysis contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this Management Discussion & Analysis includes, but is not limited to, statements regarding: the Company's expectation to generate sufficient cash from operations to meet its working capital needs; the Corporation's expected capital expenditures for 2009, including estimated construction costs, the expectation to finance those expenditures with a combination of proceeds from shareholder equity injections, short and long term borrowings and internally generated funds and the expectations that capital spending will not significantly decline in 2009; the Company's belief that changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts; the Company's expectation that delivery margins will not be impacted by migration of residential customers to alternative commodity suppliers; and the Company's expectation that it will not experience difficulty in servicing its debt obligations and paying common dividends.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability as a result of a catastrophic event or environmental upset, the competitiveness of natural gas pricing when compared with alternate sources of energy, continued population growth and new housing starts, the availability of natural gas supply, access to capital including no material adverse ratings actions by credit ratings agencies; interest rates; the ability to hedge certain risks including no counterparties to derivative instruments failing to meet obligations; and no material change in pension expense or funding requirements.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk; operational disruptions and environmental risk; price competitiveness risk including the impact of carbon taxes or other environmental policies of government; changes in economic conditions including population changes and declining housing starts; natural gas supply risks; capital and credit ratings risk including material adverse ratings actions by credit ratings agencies, interest rate risk; counterparty credit risk including counterparties to derivative instruments failing to meet obligations; and pension expense and funding risk., For additional information with respect to these risk factors, reference should be made to the section entitled "Commitments, Events, Risks and Uncertainties" in this Management Discussion & Analysis.

All forward-looking information in this Management Discussion & Analysis is qualified in its entirety by this cautionary statement and, except as required by law, the Company undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

ABOUT TERASEN GAS

On February 26, 2007, KMI, the Company's former parent, announced that it had entered into a definitive agreement with Fortis Inc. to sell Terasen and its principal natural gas transmission and distribution assets, including its subsidiaries Terasen Gas and Terasen Gas (Vancouver Island) Inc. as well as other activities including Terasen Energy Services. The sale did not include the petroleum transportation subsidiaries nor investments under the Kinder Morgan Canada name. The purchase price of approximately $3.7 billion included the assumption of approximately $2.4 billion of debt. The transaction closed on May 17, 2007.

Terasen Gas is the largest distributor of natural gas in British Columbia, serving approximately 834,000 customers in more than 100 communities. Major areas served by Terasen Gas are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of the province. Terasen Gas provides transmission and distribution services to its customers, and obtains natural gas supplies on behalf of residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through the Company's Southern Crossing Pipeline, from Alberta.

RESULTS OF OPERATIONS

NET EARNINGS

Terasen Gas reported earnings of $43.3 million for the three months ended December 31, 2008 compared to earnings of $40.7 million in the corresponding quarter of 2007. For the twelve months ended December 31, 2008, net earnings were $91.5 million compared to earnings of $78.2 million in the twelve months of 2007. The higher earnings in the current quarter and on a year to date basis are primarily due to the settlement in 2008 of various tax matters including those with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of retroactive amending Quebec tax legislation, the effect of recognition the benefit of tax re-assessments related to losses that expired on change of control in 2005 plus the effect of a higher allowed return on equity in 2008.

SELECTED ANNUAL INFORMATION

Years ended December 31 *(in millions of dollars)*	**2008**	**2007**	**2006**
Total revenues	$ 1,664.6	$ 1,524.6	$ 1,525.3
Net income[1]	91.5	78.2	68.4
Common dividends paid	100.0	110.9	40.0
Total assets	3,108.9	3,022.4	3,020.4
Long-term debt[2]	1,339.9	1,150.9	1,090.8
Current portion of long-term debt	61.8	189.7	251.4

1. Terasen Gas is a wholly-owned subsidiary of Fortis Inc. and accordingly earnings per share information is not disclosed.
2. Excluding current portion of long-term debt.

STATEMENT OF EARNINGS

For the three months ending December 31, 2008, revenues increased by $52.4 million while for the twelve months ending December 31, 2008, revenues increased by $140.0 million, compared to the corresponding periods in 2007. Cost of natural gas changed on a year-over-year basis, up $47.8 million in the fourth quarter and up $134.8 million for the twelve months ended December 31, 2008. Higher revenues and cost of natural gas for the three and twelve months ended December 31, 2008 reflect higher consumption in the current quarter and for the year due to cooler weather on a period over period basis. Changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts.

For the three and twelve months ended December 31, 2008, operation and maintenance expenses increased by $5.3 and $6.0 million respectively, as compared with the corresponding periods of 2007. The increase in operating and maintenance expenses for the three months and twelve months is a result of higher labour costs in the current year partially offset by lower non-labour costs in the current year versus the comparative period. Non-labour costs are lower in the current year primarily due to the absence of incremental costs in 2007 associated with the Fortis transaction offset by higher bad debt and customer care costs in the current quarter and on a year-to-date basis.

For the three months and twelve months ended December 31, 2008, financing costs increased by $0.4 million and $3.6 million respectively. Higher borrowing costs in the current year are due to higher borrowing rates in the current period and incrementally greater short-term borrowings versus the same period in the prior year. Income taxes for the three and twelve months of 2008 were lower than in the comparable periods of 2007 due to lower earnings, a lower effective tax rate and the net impact of the settlement of various tax matters including the retroactive amending tax legislation. During the year, the Company reached a settlement with Revenu Quebec and Canada Revenue Agency related to amounts owing as a result of retroactive amending Quebec tax legislation. The legislation was passed in 2006 for the purpose of challenging certain inter-provincial Canadian tax structures. Additionally, the Company received re-assessments relating to amending prior years tax returns for losses that would have otherwise expired due to the change in control on acquisition of Terasen by Knight Inc. As a result of the tax settlement and re-assessments, an earnings benefit of approximately $11.6 million was recognized.

Terasen Gas net customer additions during 2008 were 9,256, down from 9,939 in 2007. The weakening housing and construction markets contributed to lower net customers additions in 2008 compared to 2007. In addition, the growth in multi-family housing impacted net additions as natural gas use is less prevalent in this type of dwelling. Terasen Gas industrial and transportation sales volumes decreased by 4,521.4 terajoules, mainly due to lower volumes for pulp and paper customers. Terasen Gas earns approximately the same margin regardless of whether a customer contracts for sales or transportation service.

REGULATION

Terasen Gas' rates are based on estimates of several items, such as natural gas sales volumes, cost of natural gas, and interest rates. In order to manage the risks of forecast error associated with some of these estimates, a number of regulatory deferral accounts are in place.

Two mechanisms to ameliorate unanticipated changes in forecast items have been implemented specifically for Terasen Gas. The first, originally called the Gas Cost Reconciliation Account (GCRA), relates to the recovery of all gas costs through a deferral account which captures variances (overages and shortfalls) from forecasts. Balances are either refunded to or recovered from customers via a quarterly review and application to the BCUC.

Creation of the GCRA was approved by the BCUC in October 1993. Effective April 2004, the GCRA was split into two new deferral accounts called the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA). The CCRA and MCRA were created to support customer commodity choice (unbundling) and the refund / recovery mechanism works the same as that used for the GCRA. The second mechanism seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism (RSAM).

The RSAM and CCRA/MCRA accounts reduce Terasen Gas' earnings exposure to earnings volatility by deferring any variances between projected and actual gas consumption and gas costs, and refunding or recovering those variances in rates in subsequent periods. Variances in usage by large volume, industrial transportation and sales customers are not covered by these deferral accounts as their usage is more predictable and less likely to be significantly affected by weather.

In 2008, the net balances of the RSAM and CCRA/MCRA accounts decreased to a receivable of $22.4 million from a receivable of $72.9 million in 2007. Mark to market adjustments on commodity cost hedges, which are out of the money at December 31, 2008 and 2007, account for $4.5 million of the change. In order to ensure that the balances in the CCRA/MCRA account are recovered on a timely basis, Terasen Gas prepares and files quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas costs. These rate adjustments ignore the temporal effect of derivative valuation adjustments on the balance sheet and instead reflect the forward forecast of gas costs over the recovery period.

Short-term and long-term interest rate deferral accounts are also in place to absorb interest rate fluctuations. The interest rate deferral accounts effectively fixed the interest rate on short-term funds attributable to Terasen Gas' regulated assets at 5.00% during 2008 and 4.75% for 2007. The effective fixed short-term interest rate for 2009 has been set at 4.25%. Any variations from this rate are deferred.

ALLOWED RETURN ON EQUITY (ROE) AND CAPITAL STRUCTURE

Terasen Gas' allowed ROE is determined annually based on a formula that resets annually off a forecast of 30 Year Canada Bonds plus a 3.90% risk premium when the forecast yield on 30 Year Canada Bond is 5.25%. The risk premium is adjusted annually by 75% of the difference between 5.25% and the forecast yield on 30 Year Canada Bonds. For 2008, the application of the ROE formula set Terasen Gas' allowed ROE at 8.62%, up from 8.37% in 2007. The deemed equity component for Terasen Gas is 35.01%, unchanged from 2007. For 2009, the allowed ROE has been set at 8.47% for Terasen Gas.

2008-2009 PERFORMANCE BASED RATE PLAN (PBR)

In July 2003, Terasen Gas received BCUC approval of a negotiated settlement for a 2004-2007 PBR. The PBR Settlement establishes a process for determining Terasen Gas' delivery charges and incentive mechanisms for improved operating efficiencies. The four-year agreement included incentives for Terasen Gas to operate more efficiently through the sharing of the benefits between Terasen Gas and its customers. The PBR Settlement includes ten service quality measures designed to ensure Terasen Gas maintained adequate service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between Terasen Gas and interested parties regarding its current performance and future activities.

Operation and maintenance costs and base capital expenditures were subject to an incentive formula reflecting increasing costs due to customer growth and inflation, less an adjustment factor based on 50 percent of inflation during the first two years of the PBR and 66 percent of inflation during the last two years. Base capital expenditure amounts are a function of customer numbers and projected customer additions. The PBR Settlement provides for a 50/50 sharing mechanism of earnings above or below the allowed return on equity beginning in 2004.

In 2007, Terasen Gas applied for an extension of the 2004-2007 PBR settlement agreement. The application requested approval to extend the existing settlement term for 2008-2009. On March 23, 2007, the BCUC approved the application as filed.

UNBUNDLING

Over the past several years, Terasen Gas, the BCUC and a number of interested parties have laid the groundwork for the introduction of natural gas commodity unbundling. On November 1, 2004, commercial customers of Terasen Gas became eligible to sign up to buy their natural gas commodity supply directly from third-party suppliers. Terasen Gas continues to provide delivery of the natural gas. Approximately 80,000 commercial customers are eligible to participate in commodity unbundling. By December 31, 2008, 19,800 customers elected to participate in this program.

During 2006, the BCUC approved offering commodity supply choice to residential customers. The BCUC agreed to open a portion of the Province's residential natural gas market to competition, allowing homeowners to sign long-term fixed price contracts for natural gas with companies other than Terasen Gas starting in May 2007. Consumers can choose to remain with Terasen Gas or sign with a marketer, in which case they began receiving gas at the marketer's rate starting in November 2007. Terasen Gas will continue to provide delivery service to unbundled customers and delivery margins are not expected to be impacted by migration of residential customers to alternative commodity suppliers. Approximately 748,000 residential customers are eligible to participate in commodity unbundling. By December 31, 2008, 115,500 customers elected to participate in this program.

MUNICIPAL LEASING TRANSACTIONS

The Company has developed a leasing arrangement that allows Terasen Gas to continue to operate the gas distribution assets by effectively selling the assets to the municipality and leasing them back for a 17 year period. After 17 years, Terasen Gas has an option to repurchase the assets at depreciated value. At December 31, 2008, Terasen Gas had entered into transactions involving a total value of $153.0 million. In addition, the municipalities participating in the leasing transactions have the right each year to acquire any new asset additions within their boundaries at cost, subject to the same repurchase option at the end of the initial 17 year lease term.

COMMITMENTS, EVENT, RISK AND UNCERTAINTIES

The Company is subject to commitments, events, risks or uncertainties that may affect the Company's future performance including revenue and income or loss. The Company's key risk factors include, but are not limited to the following:

REGULATION

Through the regulatory process, the BCUC approves the return on equity which Terasen Gas is allowed to earn, in addition to various other aspects of utility operations. In addition, the recovery of costs incurred in constructing and operating the gas utility is subject to the approval of the BCUC. Fair regulatory treatment that allows Terasen Gas to earn a fair risk adjusted rate of return comparable to that available on alternative, similar risk investments is essential for maintaining service quality as well as ongoing capital attraction and growth. Since 1994, subject to minor modifications, the allowed ROE has been set based on a formula linked directly to forecast 30 year Canada Bond yields which have steadily declined in recent years. It is essential that the Company maintain good relationships with its various regulators and customer representatives. Terasen Gas will be seeking changes to the current generic ROE adjustment mechanism and increases to deemed equity thickness to more fair and appropriate levels. The Company intends to file an application with the BCUC in the second quarter of 2009.

Terasen Gas' 2004-2007 PBR settlement agreement, which has been extended through 2009, includes incentive mechanisms that provide Terasen Gas with an opportunity to earn returns in excess of the allowed return on equity determined by the BCUC. Upon expiry of the settlement agreement, there is no certainty as to whether new negotiated settlements will be entered into, or what the terms of the new settlements might be.

Terasen Gas is currently preparing a rate application with anticipated filing with the BCUC in the second quarter of 2009. BCUC approval of rates for 2010, and for future years, will be required. There can be no assurance that the rate orders issued will permit the Company to recover all costs actually incurred and to earn the expected rate of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the Company, the undertaking or timing of proposed upgrades or expansion projects, the issue and sale of securities, ratings assigned by rating agencies, and other matters which may, in turn, negatively impact the Company's results of operations or financial position.

OPERATIONS AND THE ENVIRONMENT

The Company is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety. The costs arising from compliance with such laws, regulations and guidelines may be material to the Company. The process of obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, contentious and expensive. Potential environmental damage and costs could arise due to a variety of events and could be material if an event happened. However, there can be no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs may have a material effect on the business, results of operations, financial condition and prospects of the Company.

The Company is exposed to environmental risks that owners and operators of properties in British Columbia generally face. These risks include the responsibility of any current or previous owner or operator of a contaminated site for remediation of the site, whether or not such person actually caused the contamination. In addition, environmental and safety laws make owners, operators and persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval. The Company has not been notified of any such regulatory action in regard to the operation or occupation of its facilities. However, it is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety laws could also lead to significant increases in costs to the Company.

The Company is exposed to various operational risks, such as pipeline leaks; accidental damage to, or fatigue cracks in mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas, which could result in significant operational disruptions and/or environmental liability. The Company believes it has taken all reasonable and prudent steps to minimize its exposure in the case of a catastrophic event or environmental upset. The Company conducts its operations utilizing an Environmental Management System which specifies impacts, control measures and audit protocols. The Company maintains comprehensive facility risk assessment, pipeline integrity management and damage prevention programs and pipeline security systems as preventive measures to mitigate the risk of a pipeline failure or other loss of system integrity. These programs are intended to reduce both the likelihood and severity of the business interruption and/or environmental liability that could result from a pipeline failure or loss of integrity.

A major natural disaster, such as an earthquake affecting the Greater Vancouver region or Vancouver Island, could severely damage Terasen Gas' natural gas transmission and distribution systems. The Company has detailed emergency preparedness plans in place to respond to natural disasters, accidents and emergencies, and regularly tests these plans in simulations involving employees and other emergency response organizations. The Company also has an insurance program which provides coverage for business interruption, liability and property damage, although the coverage offered by this program is limited. In the event of a large uninsured loss caused by a natural disaster, the Company would apply to the BCUC for recovery of these costs through higher rates. However, there is no assurance that the BCUC will approve any such application.

The actions necessary to abandon pipeline systems at the eventual end of their useful lives have not been defined and the costs of these actions may not be fully recovered in rates or tolls. Until such time as the specified requirements of abandonment and the funding mechanism for the eventual recovery of negative salvage is determined, the Company, like other Canadian pipeline systems, makes no provision for these amounts.

Terasen Gas' natural gas transmission and distribution systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the Company determines expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures which the Company believes are necessary to maintain, improve and replace their assets; the failure by the Company to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures despite maintenance programs could have a material effect on the Company.

The Company continually develops capital expenditure programs and assesses current and future operating and maintenance expenses that will be incurred in the ongoing operation. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. If actual costs exceed regulatory-approved capital expenditures, it is uncertain as to whether such additional costs will receive regulatory approval for recovery in future customer rates. The inability to recover these additional costs could have a material effect on the financial condition and results of operations of the Company. See "Regulation" for further discussion on regulatory risk.

COMPETITIVENESS

Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, because electricity prices in British Columbia continue to be set based on the historical average cost (primarily hydro-electric dams) of production, rather than based on market forces, they have remained artificially low compared to market priced electricity. As a result, the price of electricity for residential customers in British Columbia is now only marginally higher than for natural gas. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future.

The Company employs a number of tools to reduce its exposure to natural gas price volatility. These include purchasing gas for storage and adopting hedging strategies, which include a combination of both physical and financial transactions, to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive against electric rates. Activities related to the hedging of gas prices are approved by the BCUC and gains or losses accrue entirely to customers.

If natural gas pricing becomes uncompetitive with electricity prices or the price of other forms of energy, the Company's ability to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the Company's cost of service in rates charged to customers.

In 2008 the Government of British Columbia introduced changes to energy policy including greenhouse gas emission reduction targets and a consumption tax on carbon based fuels that impact the competitiveness of natural gas versus non-carbon based energy sources or alternate energy sources. It did not, however, introduce carbon tax on imported electricity generated through the combustion of carbon based fuels. The future impact of these changes in energy policy may have a material impact on the competitiveness of natural gas relative to other energy sources.

There can be no assurance that the current regulatory-approved flow through mechanisms in place allowing for the flow through of the cost of natural gas will continue to exist in the future. An inability of the Company to flow through the full cost of natural gas could materially affect the Company's results of operations, financial position and cash flows.

LABOUR RELATIONS

Approximately 75% of the employees of the Company are members of labour unions that have entered into collective bargaining agreements with the Company. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by the Company. The Company considers its relationships with its labour unions to be positive but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have an adverse effect on the results of operations, cash flow and net income of the Company.

IMPACT OF CHANGES IN ECONOMIC CONDITIONS

Typical of utilities, economic conditions in the Company's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. New customer additions at the Company are typically a result of population growth and new housing starts, which are affected by the state of the provincial economy. The Company is also affected by changes in trends in housing starts from single family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. Housing starts in 2008 were more moderate compared to the previous number of years, and the growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. Higher energy prices can dampen economic activity and reduce consumption by customers. Natural gas and crude oil prices are closely correlated with natural gas and crude oil exploration and production activity in certain of the Company's service territories. The level of these activities can influence energy demand.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of Terasen Gas, including various mitigating measures approved by regulators, helps to reduce the impact that lower energy demand, associated with poor economic conditions, may have on the Company's earnings. However, a severe and prolonged downturn in economic conditions could materially affect the Company despite regulatory measures available for compensating for reduced demand. For instance significantly reduced energy demand in the Company's service territories could reduce capital spending which would in turn impact rate base and earnings growth. Despite current depressed economic conditions and natural gas prices, which are expected to continue during 2009, the Company does not anticipate any significant decrease in capital spending in 2009.

NATURAL GAS SUPPLY

The Company is dependent on a limited selection of pipeline and storage providers, particularly in the Vancouver and Fraser Valley areas where the majority of the Company's natural gas distribution customers are located. Regional market prices have been higher from time to time than prices elsewhere in North America as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in B.C. and the U.S. Pacific Northwest.

In addition, the Company is critically dependent on a single source transmission pipeline. In the event of a prolonged service disruption on the Spectra transmission system, the Company's residential customers could experience outages, thereby affecting revenues and incurring costs to safely relight customers.

CAPITAL RESOURCES AND LIQUIDITY

The Company's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by rating agencies, adequate allowed rates of return on equity granted by the BCUC and general economic conditions. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) will not be sufficient to fund the repayment of all outstanding liabilities when due as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and to repay existing debt.

Generally, the Company is subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings impact the level of credit risk spreads on new long-term debt issues and on the Company's credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the Corporation's and operating subsidiaries' finance charges. Also, a significant downgrade in the Terasen Gas's credit ratings could trigger margin calls and other cash requirements under Terasen Gas's natural gas purchase and natural gas derivative contracts. The Company's corporate investment-grade credit ratings were confirmed and maintained during the year and the Company does not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the current global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria which may result in changes to credit rating practices and policies.

The recent and expected continued volatility in the global financial and capital markets will likely increase the cost of and affect the timing of issuance of long-term capital by the Company in 2009. The cost of borrowing is expected to increase as new long-term debt is expected to be issued at higher rates due to an increase in credit spreads. Due to the regulated nature of the Company's operations, the expected higher cost of borrowing of the utilities is eligible to be recovered in future customer rates.

To help mitigate liquidity risk, Terasen Gas has secured multi-year committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Accounting Standards Board of the Canadian Institute of Chartered Accountants has announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, effective January 1, 2011. IFRS will require increased financial statement disclosure as compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by the Company. The Company is currently considering the impact a conversion to IFRS would have on its future financial reporting. Additional information on the Company's transition to IFRS is provided in the "Future Accounting Pronouncements" section of this MD&A.

INTEREST RATES

The allowed returns on equity for the Company are determined by formulae that result in lower allowed ROEs if forecast long-term Canada bond yields decline. The Company's exposure to short-term interest rates are covered by regulatory deferral accounts, however it is exposed to changes in short-term interest rates through debt on non-regulated operations.

EMPLOYEE FUTURE BENEFITS

The Company maintains defined benefit pension plans and there is no certainty that the pension plan assets will be able to earn the assumed rate of returns. Market driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed return on the assets causing material changes in the pension expense and funding requirements. The regulated operation of the Company currently has a deferral mechanism which allows for deferral of the pension expense that is approved for recovery in rates and the actuarial pension expense. Net pension expense is impacted by, among other things, the amortization of experience and actuarial gains or losses and expected and actual return on plan assets.

Market driven changes impacting other pension assumptions, including the assumed discount rate, may also result in future contributions to pension plans that differ significantly from current estimates as well as causing material changes in pension expense. There is also measurement uncertainty associated with pension expense, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation due to measurement uncertainty inherent in the actuarial valuation process.

COUNTERPARTY CREDIT RISK

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Company is also exposed to significant credit risk on physical off-system sales. Terasen deals with high credit quality institutions in accordance with established credit approval practices. Due to recent events in the financial markets including significant international government intervention in the banking systems and financial markets the Company has further limited the financial counterparties that it transacts with and reduced available credit to, or taken additional security from, the physical off-system sales counterparties it deals with. To date the Company has not experienced any counterparty defaults and does not expect any counterparties to fail to meet their obligations however, the credit quality of counterparties, as recent events have indicated, can change rapidly.

FIRST NATIONS LANDS

The Company provides service to customers on First Nations lands and maintain gas distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Company is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as the Company. However, there can be no certainty that the settlement process will not adversely affect the business of the Company.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The Company's critical accounting estimates are discussed below.

REGULATION

Generally, the accounting policies of the Company are subject to examination and approval by the BCUC. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process and have been recorded based on previous, existing or expected regulatory orders or decisions.

Certain estimates are necessary since the regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the BCUC for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known. As at December 31, 2008, the Company recorded $93.4 million in current and long-term regulatory assets (December 31, 2007 - $112.3 million) and $59.5 million in current and long-term regulatory liabilities (December 31, 2007 - $29.2 million).

CAPITAL ASSET AMORTIZATION

Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2008, the Company's consolidated utility capital assets were $2.4 billion, or approximately 78 per cent of total consolidated assets, compared to consolidated utility assets of $2.4 billion, or approximately 79 per cent of total consolidated assets, as at December 31, 2007. Changes in amortization rates can have a significant impact on the Company's amortization expense.

As part of the customer-rate setting process, appropriate amortization rates are approved by the BCUC.

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed. Based on the results of these depreciation studies, the impact of any over or under amortization as a result of actual experience differing from that expected and provided for in previous amortization rates is generally reflected in future amortization rates and amortization expense, as such differences are reflected in future customer rates.

CAPITALIZED OVERHEADS

As required by the BCUC, Terasen Gas capitalize overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the BCUC. In 2008, GEC totaled $27.7 million (2007 - $25.5 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a significant impact on the amount recorded as operating expenses and utility capital assets.

GOODWILL IMPAIRMENT ASSESSMENTS

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment. The Company is required to perform an annual impairment test and at such time any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. In July of each year, the Company reviews for impairment of goodwill, which is based on current information and fair market value assessments of the reporting units being reviewed. Fair market value is determined using net present value financial models and management's assumption of future profitability of the reporting units. There was no impairment provision required on $0.5 million in goodwill recorded on the Company's balance sheet as at December 31, 2008.

EMPLOYEE FUTURE BENEFITS

The Company defined benefit pension plans and OPEB plans are subject to judgments utilized in the actuarial determination of the expense and related obligation. The main assumptions utilized by management in determining pension expense and obligations are the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets.

The assumed long-term rates of return on the defined benefit pension plan assets, for the purpose of estimating pension expense for 2009, is 7.25%, consistent with the assumes long-term rate of return used for 2008.

The assumed discount rates, used to measure the Company's accrued pension benefit obligations on the applicable measurement date in 2008, and to determine pension expense for 2009, was 6.25%, up from 5.25% used in 2007. The discount rates increased as a result of the impact of increased credit risk spreads on investment grade corporate bonds due to volatility in the capital markets.

The long term rate of return is based on based on the expected average return of the assets over a long period given the relative asset mix. The discount rate is determine with referred to the current market rate of interest on high quality debt instruments with cash flows which match the time and amount of expected benefit payments.

Terasen Gas expects consolidated pension expense for 2009 related to its defined benefit pension plans to be approximately $0.6 million lower than in 2008. The lower expense is due to the effect of the change in discount rate partially offset by lower returns on the assets in 2008.

The following table provides the sensitivities associated with a 100 basis point increase move in the expected long-term rate of return on plan assets and discount rate on 2008 net benefit expense and the accrued benefit pension asset and liability recorded in the Company's consolidated financial statements, as well as the impact on the accrued pension benefit obligation.

Increase (decrease) *(in millions of dollars)*	Accrued Benefit Asset	Accrued Benefit Liability	Net Benefit Expense	Benefit Obligation
1% increase in the expected rate of return	$ 2.3	$ (0.1)	$ (2.3)	$ -
1% decrease in the expected rate of return	(2.3)	0.1	2.3	-
1% increase in the discount rate	(1.1)	(0.6)	0.5	(13.3)
1% decrease in the discount rate	(2.4)	0.9	3.3	15.2

The above table reflects the changes before the effect of the regulatory deferral account which would defer most of the effect on the expense.

Other assumptions applied in measuring defined benefit pension expense and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The Company's OPEB plans are also subject to judgments utilized in the actuarial determination of the expense and related obligation. Except for the assumptions of the expected long-term rate of return on plan assets and average rate of compensation increase, the above assumptions, along with health care cost trends, were also utilized by management in determining OPEB plan expense and obligations.

As disclosed under the "Commitments, Event, Risk and Uncertainties" section of this MD&A, the Terasen Gas has regulatory-approved mechanisms to defer variations in pension expense from forecast pension expense, used to set customer rates, as a regulatory asset or a regulatory liability.

As at December 31, 2008, the Company had a consolidated accrued benefit asset of $207.9 million (December 31, 2007 - $237.4 million) and a consolidated accrued benefit liability of $298.0 million (December 31, 2007 - $304.7 million). During 2008, the Company recorded consolidated net benefit expense of $9.5 million (2007 - $10.4 million).

ASSET RETIREMENT OBLIGATIONS (``ARO'S")

In measuring the fair value of AROs, the Company is required to make reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. The Company does not currently have any identified ARO's and as such no amounts have been recorded as at December 31, 2008 and 2007. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the transmission and distribution systems are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licenses, permits and laws are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and to ensure the continued provision of service to customers. In the event that environmental issues are identified, or the applicable licenses, permits, laws or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

REVENUE RECOGNITION

The Company recognizes revenue on an accrual basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish gas consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the approved rates. The development of the sales estimates requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2008, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $222.8 million (December 31, 2007 - $153.9 million) on annual consolidated operating revenues of $1.64 billion (2007 - $1.52 billion).

CONTINGENCIES

The Company is subject to various legal proceedings and claims that arise in the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's financial position or results of operations. Contingencies are described in note 13 to the Company's annual financial statements.

QUARTERLY FINANCIAL INFORMATION

($ millions)	For the three months ended				
2008	**Mar-31**	**Jun-30**	**Sep-30**	**Dec-31**	**Total**
Revenues	**$ 563.8**	**$ 336.1**	**$ 227.7**	**$ 537.0**	**$1,664.6**
Net income (loss)	**50.6**	**3.9**	**(6.3)**	**43.3**	**91.5**
2007					
Revenues	$ 559.3	$ 293.3	$ 187.4	$ 484.6	$1,524.6
Net income (loss)	46.8	2.8	(12.1)	40.7	78.2

Because of natural gas consumption patterns, the natural gas transmission and distribution operations of Terasen Gas normally generate higher net earnings in the first and fourth quarters and lower net earnings in the second quarter, which are partially offset by net losses in the third quarter. As a result, interim earnings statements are not indicative of earnings on an annual basis.

LIQUIDITY AND CAPITAL RESOURCES

CONSOLIDATED CASH FLOW

Years ended December 31 *(in millions of dollars)*	**2008**	2007
Cash flow provided by (used for):		
Operating activities	**$ 198.5**	$ 117.9
Investing activities	**(85.6)**	(97.3)
Financing activities	**(105.4)**	(21.5)
Net increase (decrease) in cash	**$ 7.5**	$ (0.9)

CASH FLOW FROM OPERATING ACTIVITIES

Cash flow from operating activities increased from $117.9 million in 2007 to $198.5 million in 2008 due to a number of factors. Cash from operations refers to cash generated before the impact of working capital. Cash from operations for the three months ended December 31, 2008 was $59.7 million compared to $51.2 million in the corresponding period of 2007. Cash from operations for the twelve months ended December 31, 2008 was $165.2 million, compared to $146.2 million in the corresponding period of 2007. The increase in cash from operations for the three and twelve months ended December 31, 2008 is mainly a result of higher net earnings in the comparable periods of 2008 versus 2007.

Between December 31, 2007 and December 31, 2008, accounts receivable, inventories of gas in storage and supplies, accounts payable and accrued liabilities, excluding the mark to market on gas derivatives have increased while the current portion of rate stabilization accounts decreased as a result of the cooler weather and higher commodity cost of gas charged to customers Due to the greater impact of these changes in 2008 as compared to 2007, cash flow generated from operating activities has increased.

INVESTING ACTIVITIES

Capital expenditures totaled $122.1 million in 2008 which are comparable with $108.4 million in 2007.

FINANCING ACTIVITIES

On May 13, 2008, Terasen Gas issued $250.0 million of Medium Term Note Debentures at a coupon interest rate of 5.80%. The proceeds were used to repay current debt maturities of $188.0 million which matured on June 2, 2008 and the remainder of the proceeds were used to pay down Terasen Gas' operating line.

On October 2, 2007, the Company issued $250.0 million of Medium Term Note Debentures at a coupon interest rate of 6.00%. The proceeds were used to repay the current debt maturities which matured during October 2007.

On August 24, 2007, the Company renegotiated and extended its credit facility for five years with similar terms to the original facility and common for such term credit facilities. The $500 million unsecured committed revolving credit facility is with a syndicate of banks and matures in August 2012. In 2008, under the terms of the agreement, the facility was extended to mature in August 2013.

As at December 31, 2008, the Company had lines of credit in place totaling $500.0 million to finance cash requirements. These lines enable the respective companies to borrow directly from their bankers, issue bankers' acceptances and support commercial paper issuance. Bank lines of $218.0 million were unutilized at the end of 2008. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the Canadian market at rates generally below bank prime. Terasen does not have, nor does it expect to have, any defaults or arrears.

Dividends on common shares totaled $100.0 million in 2008 compared to $110.9 million paid in 2007.

CONTRACTUAL OBLIGATIONS

The Company has entered into operating leases for certain building space and natural gas transmission and distribution assets. In addition, the Company enters into gas purchase contracts. The following table sets forth the Company's operating leases, gas purchase obligations and employee benefit plan contributions due in the years indicated:

	Operating leases	Purchase obligations	Employee benefit plans	Total
2009	$ 15.4	$ 360.4	$ 7.9	$ 383.7
2010	15.0	26.9	5.9	47.8
2011	14.7	22.8	-	37.5
2012	14.4	-	-	14.4
2013	13.5	-	-	13.5
Thereafter	85.5	-	-	85.5
	$ 158.5	$ 410.1	$ 13.8	$ 582.4

Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect at December 31, 2008. The employee benefit plan contributions have been estimated up to the date of the next actuarial valuation for each plan unless the valuation falls in the next twelve months then the Company has provided for an estimate of the contributions. Employee benefit plan contributions beyond the date of the next actuarial valuation cannot be accurately estimated.

FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets as at December 31, 2008 compared to December 31, 2007.

Balance Sheet Item	Increase(Decrease) ($ millions)	Explanation
Long-term debt (including current portion)	61.1	The increase is mainly a result of the Company issuing more long-term debt than that maturing in the year with the excess used to pay down short-term notes.
Short-term notes	(66.5)	The decrease in short-term notes is mainly due to the Company's long term debt issuance noted above with the excess proceeds used to pay down short-term notes.
Rate stabilization accounts (including current and long term)	(50.4)	The decrease in the net asset position is mainly due to the fair value mark to market for the gas derivatives being lower at December 31, 2008 versus December 31, 2007. Additionally, the company has been collecting higher amounts from customers while gas prices have declined.
Accounts receivable	35.8	The increase in accounts receivable is due to cooler weather and an increase in the commodity cost of gas charged to customers in 2008 compared to 2007.
Accounts payable and accrued liabilities	34.7	The increase is mainly due to higher gas cost payable due to cooler weather in the current year compared to the prior year.

WORKING CAPITAL

The Company's working capital requirements fluctuate seasonally based on natural gas consumption. Given the relatively low-risk, regulated nature of its business, Terasen Gas is able to maintain negative working capital balances. Terasen Gas maintains adequate committed credit facilities to meet its working capital requirements. On an annual basis, Terasen Gas generates sufficient cash flow to meet its working capital requirements.

CASH FLOW

It is expected that operating expenses and interest costs will generally be paid out of operating cash flows, with varying levels of residual cash flow available for capital expenditures and/or for dividend payments. Cash required to complete capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Terasen and long-term debt issues.

The Company's ability to service its debt obligations and pay dividends on its common shares is dependent on the financial results of the Company. Cash required to support capital expenditure programs is expected to be derived with borrowings from short term borrowings. Depending on the timing of cash payments, borrowings under the Company's credit facility may be required from time to time to support the servicing of debt and payment of dividends.

The Company does not expect any significant decrease in operating cash flows in 2009, in light of the expected continued downturn in the global economy and, therefore, does not anticipate any difficulty in servicing its debt obligations and paying common dividends. Also, the Company do not anticipate any difficulty in sourcing the cash required to fund their 2009 capital expenditure programs.

DIVIDEND RESTRICTIONS

As part of its approval of the acquisition of Terasen by KMI, as well as the subsequent sale from KMI to Fortis, the BCUC imposed a number of conditions intended to ring-fence Terasen Gas from Terasen. These restrictions included a prohibition on the payment of dividends unless Terasen Gas has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. As a result of this and the decision issued by the BCUC on March 2, 2006 Terasen Gas must currently maintain a percentage of common equity to total rate base that is at least 35.01%.

In 2008, none of these restrictions constrained the distribution of earnings not otherwise needed for reinvestment.

CREDIT RATINGS

Securities issued by Terasen Gas are rated by DBRS Inc. (DBRS) and Moody's Investors Service Inc. (Moody's). The ratings assigned to securities issued by Terasen Gas are reviewed by these agencies on an ongoing basis.

The table below summarizes the ratings assigned to the Company's various securities. The DBRS rating is as of May 20, 2008 and the Moody's rating is as of July 17, 2008.

CREDIT RATINGS	DBRS	Moody's
Commercial paper	R-1 (Low)	-
Secured long-term debt	A	A2
Unsecured long-term debt	A	A3

After reassessing its relationship with Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies (Canada) Corporation (S&P), Terasen Gas decided early in 2004 to discontinue the engagement of S&P to provide credit ratings on the debt of Terasen Gas. The Company believes the credit ratings issued by Moody's and DBRS will be sufficient to service the requirements of creditors and maintain the Company's access to capital. S&P continues to provide an unsolicited rating on the Company's outstanding debt based on publicly available information. As of December 17, 2008 the Company's unsecured long-term debt was rated A by S&P.

A downgrade of Terasen Gas below investment grade by any of the major credit rating agencies could trigger margin calls and other cash requirements under Terasen Gas' gas purchase and commodity derivative contracts.

PROJECTED CAPITAL EXPENDITURES

Terasen Gas has estimated total 2009 consolidated capital expenditures, before customer contributions, of $152.7 million. Major capital expenditures in 2009 include the Gateway Infrastructure Project ($15.5 million) Fraser River South Bank South Arm Rehabilitation project ($25.4 million), and Customer Information System ($12.5 million) and an upgrade of SAP Core applications ($2.5 million). The Company expects to finance capital expenditures in 2009 with a combination of long-term debt issuance, short-term borrowings and internally generated funds.

OFF-BALANCE SHEET ARRANGEMENTS

There are no material off-balance sheet arrangements.

TRANSACTIONS WITH RELATED PARTIES

The Company received $3.3 million in 2008 (2007 – $4.1 million) from Terasen Gas (Vancouver Island) Inc. ("TGVI"), a company under common control, for transporting gas through the Company's pipeline system.

The Company paid approximately $47.0 million during the year ended December 31, 2008 (2007 – $45.2 million) for customer care and billing services to a limited partnership. The Company's parent, Terasen, holds a 30% interest in the limited partnership and jointly controls it. The Company is committed to pay approximately $43.6 million as base contract fees for 2009.

The Company paid $8.5 million in 2008 (2007 – $8.5 million) to Terasen, the Company's parent, for management services.

The Company charged companies under common control $6.6 million in 2008 (2007 – $6.1 million) for management services.

The Company's indirect parent, Fortis Inc., grants stock options to certain employees of the Company under its stock option plans. For the year ended December 31, 2008, the Company was charged, and recorded an expense of $0.3 million (2007 $0.1 million) for the fair value of the stock compensation granted by Fortis Inc.

Related party transactions are recorded at the exchange amount.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants ("CICA").

a) Section 3862, *Financial Instruments – Disclosures*, and Section 3863, *Financial Instruments – Presentation*, require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed.

b) Section 1535, *Capital Disclosures,* requires the Company to disclose additional information about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding the Corporation's objectives, policies and processes for managing capital.

c) Section 3031, *Inventories,* requires inventories to be measured at the lower of cost or net realizable value, disallows the use of a last-in first-out inventory costing methodology, and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This standard is to be applied retrospectively. As at January 1, 2008, supplies and other inventories of $6.6 million ($5.8 million as at January 1, 2007) were reclassified to property, plant and equipment from inventory on the balance sheet as they are held for the development, construction, maintenance and repair of other property, plant and equipment. During the year ended December 31, 2008, gas in storage inventories of $1,152.1 million (2007 - $1,017.3 million) were expensed and reported in cost of natural gas on the consolidated statement of earnings and comprehensive earnings.

FUTURE ACCOUNTING PRONOUNCEMENTS

International Financial Reporting Standards ("IFRS"): In February 2008, the Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an IFRS Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011.

On June 27, 2008 the Canadian Securities Administrators ("CSA") issued Staff Notice 52-321, *Early Adoption of IFRS* which indicated that the CSA would be prepared to grant an exemption to allow Canadian financial statement issuers to adopt IFRS early on a case-by-case basis, provided that they could demonstrate that they met certain conditions. Terasen Gas is not planning to adopt IFRS early.

The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section - *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to the IFRS Omnibus Exposure Draft.

Terasen Gas is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Terasen Gas does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required as well as systems changes that may be necessary to gather and process the required information.

Terasen Gas commenced its IFRS conversion project in 2007 and has established a formal project governance structure which includes the audit committees, senior management and a project team. Overall project governance, management and support is coordinated by Fortis. Regular reporting occurs to the Audit Committee of the Board of Directors. An external expert advisor has been engaged to assist in the IFRS conversion project.

The Terasen Gas IFRS conversion project consists of three phases: Scoping and Diagnostics, Analysis and Development, and Implementation and Review.

Phase One: Scoping and Diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, has been completed. The resulting identified areas of accounting difference of highest potential impact to the Company, based on existing IFRS, are rate-regulated accounting, property plant and equipment, provisions and contingent liabilities, employee benefits, impairment of assets, income taxes, and initial adoption of IFRS under the provisions of IFRS 1 *First-Time Adoption of IFRS*.

Phase Two: Analysis and Development is nearing completion, and involves detailed diagnostics and evaluation of the financial impacts of various options and alternative methodologies provided for under IFRS; identification and design of operational and financial business processes; initial staff and audit committee training; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application upon transition to IFRS; summarization of 2011 IFRS disclosure requirements; and development of required solutions to address identified issues.

It is anticipated that the adoption of IFRS will have an impact on information systems requirements. The Company is assessing the need for system upgrades or modifications to ensure an efficient conversion to IFRS. As part of Phase Two, information systems plans are being prepared for implementation in Phase Three. The extent of the impact on the Company's information systems is not reasonably determinable at this time.

Phase Three: Implementation and Review, expected to commence mid-year 2009, will involve the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and further training programs across the Company's finance and other affected areas, as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS in business processes; and, audit committee approval of IFRS-compliant financial statements.

Terasen Gas will continue to review all proposed and continuing projects of the IASB, particularly the project on rate-regulated activities that was recently added to the IASB's technical agenda, and proposed amendments to IFRS 1 for entities with operations subject to rate regulation, and will participate in any related processes as appropriate.

Rate-Regulated Operations: In March 2007, the AcSB issued an Exposure Draft on rate-regulated operations that proposed: (i) the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, of the CICA Handbook providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation be removed; (ii) the explicit guidance for rate-regulated operations provided in Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxe*s, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*, be removed; and (iii) Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation*, be retained as is. The AcSB has also observed that relying on US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* ("FAS 71"), as another source of Canadian GAAP in the absence of CICA Handbook guidance addressing the specific circumstances of entities subject to rate regulation, is consistent with Section 1100 when the qualifying criteria of FAS 71 are met.

In August 2007, the AcSB issued a Decision Summary on the Exposure Draft that supported the removal of the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, and the amendment to Section 3465, *Income Taxes,* to recognize future income tax liabilities and assets as well as an offsetting regulatory asset or liabilities for entities subject to rate regulation. Both changes will apply prospectively for fiscal years beginning on or after January 1, 2009. It was also decided that the current guidance pertaining to property, plant and equipment, disposal of long-lived assets and discontinued operations, and consolidated financial statements be maintained and that the existing AcG-19 will not be withdrawn from the Handbook but that the guidance will be updated as a result of the other changes. The AcSB also decided that the final Background Information and Basis for Conclusions associated with its rate regulation project would not express any views of the AcSB regarding the status of US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, as an "other source of GAAP" within the Canadian GAAP hierarchy.

Effective January 1, 2009, the impact on the Company of the amendment to Section 3465, *Income Taxes,* will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to or recovered from customers in future gas rates. Currently, the Company uses the taxes payable method of accounting for income taxes on regulated earnings. The estimated effect on the Company's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2008, would have been an increase in future tax liabilities of $261.8 million, including those associated with income taxes that will become payable on future revenues as they are collected from customers when the tax timing differences reverse. There would also be a corresponding increase in regulatory assets. Terasen Gas is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate regulated operations.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Company must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, 3061, 3465, and 3475. All assets and liabilities arising from rate regulation do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. These assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Company's consolidated financial statements if it had adopted the removal of the temporary exemption in Section 1100, for the year ended December 31, 2008. Terasen Gas is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate-regulated operations.

Effective January 1, 2009, the Company will be adopting the new CICA Handbook Section 3064 – *Goodwill and Intangible Assets* which converges Canadian GAAP for goodwill and intangible assets with IFRS. The new standard provides for more comprehensive guidance on intangible assets, in particular for internally developed intangible assets. The Company is still assessing the financial reporting impact of adopting this standard.

FINANCIAL AND OTHER INSTRUMENTS

FAIR VALUE ESTIMATES

	December 31, 2008		December 31, 2007	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and short-term investments [1]	**$ 13.1**	**$ 13.1**	$ 5.6	$ 5.6
Loans and receivables				
Accounts receivable [1,2]	**345.9**	**345.9**	310.1	310.1
Long term receivables [1,2]	**9.1**	**9.1**	9.2	9.2
Other financial liabilities				
Short-term notes [1,2]	**238.5**	**238.5**	305.0	305.0
Accounts payable and accrued liabilities [1,2]	**365.9**	**365.9**	331.2	331.2
Long-term debt, including current portion [3,4,5]	**1,401.7**	**1,454.2**	1,340.6	1,550.3

1 Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.
2 Carrying value approximates amortized cost.
3 Carrying value is measured at amortized cost using the effective interest rate method.
4 Carrying value at December 31, 2008 is net of unamortized deferred financing costs of $12.8 million (2007 - $10.8 million). On January 1, 2007, deferred financing costs were reclassified from other assets in accordance with the transitional provisions of CICA Section 3855. The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates or tolls.
5 Fair value is calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2008, or by using available quoted market prices.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

DERIVATIVE INSTRUMENTS

The Company hedges its exposure to fluctuations in natural gas prices and through the use of derivative instruments. The table below indicates the valuation of the derivative instruments as at December 31, 2008.

Asset (Liability)	**December 31, 2008**		December 31, 2007	
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Natural Gas Commodity Swaps and Options[1,2]	**$ (70.7)**	**$ (70.7)**	$ (77.3)	$ (77.3)
Gas purchase contract premiums[1,2]	**(6.2)**	**(6.2)**	4.8	4.8

[1] The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates. The natural gas derivatives fair values have been determined using published market prices for natural gas commodities.

[2] The derivatives entered into by Terasen Gas relate to regulated operations and any resulting gains or losses are, subject to regulatory approval, passed through to customers in future rates.

OUTSTANDING SHARE DATA

As at February 4, 2009, Terasen Gas had issued and outstanding 59,591,732 common shares.

Terasen Gas is an indirect wholly-owned subsidiary of Fortis.

ADDITIONAL INFORMATION

Additional information relating to Terasen Gas Inc., including its Annual Information Form, is available on SEDAR at www.sedar.com.

Attachment 84.8

Terasen Gas Inc.
A subsidiary of Fortis Inc.

Annual Information Form

For the Year Ended December 31, 2008
dated
February 18, 2009

TABLE OF CONTENTS

Forward Looking Statements

Certain statements contained in this Annual Information Form contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability as a result of a catastrophic event or environmental upset, the competitiveness of natural gas pricing when compared with alternate sources of energy, continued population growth and new housing starts, the availability of natural gas supply, access to capital including no material adverse ratings actions by credit ratings agencies; interest rates and the ability to hedge certain risks including no counterparties to derivative instruments failing to meet obligations; no material change in pension expenses or funding requirements and no prejudice to the Company's rights under first nations land settlements.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk; operational disruptions and environmental risk; price competitiveness risk including the impact of carbon taxes or other environmental policies of government; changes in economic conditions including population changes and declining housing starts; natural gas supply risks; capital and credit ratings risk including material adverse ratings actions by credit ratings agencies, interest rate risk; counterparty credit risk including counterparties to derivative instruments failing to meet obligations; pension expense and funding risk; and first nations land settlement risk. For additional information with respect to these risk factors, reference should be made to the section entitled "Risk Factors" in this Annual Information Form.

The forward-looking information in this Annual Information Form includes, but is not limited to, statements regarding: the Company's expectation that earnings and delivery margins will not be impacted by industrial customers choosing to arrange their own supply of natural gas or by the migration of residential suppliers to alternative commodity suppliers; the Company's expectation that unanticipated changes in sales volume can be ameliorated as a result of regulatory deferral accounts; the Company's belief that interest rate deferral accounts will absorb the impact of interest rate fluctuations; the Company's expectation that the value of future arrangements with municipalities to transfer the economic risks and rewards of ownership of distribution assets will not be material; the expectations that capital spending will not significantly decline in 2009 and the Company's expectation that compliance with environmental laws and regulations will not have a material effect on the Company's capital expenditures, earnings or competitive position.

All forward-looking information in this Annual Information Form is qualified in its entirety by this cautionary statement and, except as required by law, the Company undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE STRUCTURE

Terasen Gas Inc. ("Terasen Gas" or the "Company") was formed by the amalgamation on July 1, 1989 under the *Company Act* (British Columbia) a predecessor to the *Business Corporations Act* (British Columbia), of Inland Natural Gas Co. Ltd. ("Inland"), B.C. Gas Inc., Columbia Natural Gas

Limited and Fort Nelson Gas Ltd. On July 1, 1993 pursuant to an arrangement between Terasen Gas and a subsidiary, Terasen Gas changed its name to "BC Gas Utility Ltd.". Effective April 25, 2003, the Company changed its name to “Terasen Gas Inc.” The head office and registered office of Terasen Gas is located at #1000 - 1111 West Georgia Street, Vancouver, British Columbia, V6E 4M3. Terasen Gas means Terasen Gas Inc. together with its subsidiary companies. Terasen Gas is a wholly-owned subsidiary of Terasen Inc. ("Terasen"), which is in turn a wholly-owned indirect subsidiary of Fortis Inc.

On January 1st, 2007, the Company and one of its subsidiaries, Terasen Gas (Squamish) Inc., were amalgamated.

In this annual information form, references to “Terasen Gas” or the “Company” are to Terasen Gas Inc., “Terasen” refers to “Terasen Inc.”, and “TGVI” refers to Terasen Gas (Vancouver Island) Inc.

DESCRIPTION OF THE BUSINESS

Terasen Gas provides natural gas transmission and distribution service to over 100 communities in British Columbia with a service territory that has an estimated population of approximately four million. The Company is one of the largest natural gas distribution companies in Canada. As at December 31, 2008 Terasen Gas and its subsidiaries transported and distributed natural gas to approximately 834,000 residential, commercial and industrial customers, representing approximately 86 per cent of the natural gas users in British Columbia. Terasen Gas' service area extends from Vancouver to the Fraser Valley and the interior of British Columbia. The transmission and distribution business is carried on under statutes and franchises or operating agreements granting the right to operate in the municipalities or areas served. Terasen Gas is rate regulated by the British Columbia Utilities Commission (BCUC).

On February 26, 2007, Knight Inc. (formerly known as Kinder Morgan, Inc.), Terasen’s former parent, announced that it had entered into a definitive agreement with Fortis Inc. to sell Terasen and its principal natural gas transmission and distribution assets, including its subsidiaries Terasen Gas and Terasen Gas (Vancouver Island) Inc. as well as other activities including Terasen Energy Services. The sale did not include the petroleum transportation subsidiaries nor investments under the Kinder Morgan Canada name. The transaction closed on May 17, 2007.

DISTRIBUTION SERVICES

Natural gas distribution services are the primary source of revenue for Terasen Gas. Distribution services delivered to residential, small commercial and industrial customers are predominantly on a non-contractual basis, whereby the customers are charged based on general services provided. Larger commercial and industrial customers are normally provided with services on a contractual basis.

Terasen Gas has approximately 2,375 commercial and industrial customers that arrange for some or all of their own gas supply and use Terasen Gas' transportation services for delivery. Notwithstanding shifts over time between utility supply and direct purchases, Terasen Gas' earnings remain unaffected since Terasen Gas' margins remain substantially the same whether or not customers choose to buy natural gas from Terasen Gas or arrange their own supply. Industrial transportation customers arranging for their own supply in fact reduce the credit risk to Terasen Gas.

Of Terasen Gas' industrial customers, approximately 146 are on interruptible service. The majority of these customers are capable of switching to alternate fuels. Forecast variances in industrial consumption can have an impact on the Company's earnings, however forecasts are updated annually based largely on an annual survey of industrial customers.

Of the various industries that comprise Terasen Gas’ industrial market, the pulp and paper and wood products industries combined comprise approximately 36 percent of total throughput. All other industries individually represent less than 10 percent of total throughput.

Terasen Gas also owns and operates a propane distribution system in Revelstoke, B.C.

GAS PURCHASE AGREEMENTS

In order to acquire supply resources that ensure reliable natural gas deliveries to its customers, Terasen Gas purchases supply from a select list of producers, aggregators, and marketers by adhering to strict standards of counterparty creditworthiness, and contract execution/management procedures. Terasen Gas contracts for approximately 113 petajoules (PJ) of baseload and seasonal supply, of which 81 PJ is delivered off the Spectra Energy Gas Transmission ("Spectra") system and 14 PJ is comprised primarily of Alberta sourced supply transported into British Columbia via TransCanada Pipelines Limited ("TransCanada") Alberta and B.C. systems. The remaining 18 PJ of baseload and seasonal supply is sourced at Sumas. The majority of supply contracts in the current portfolio are seasonal for either the summer (April to October) period or winter (November to March) period with a few contracts one year or longer in length.

The Spectra and TransCanada transportation tolls are regulated by the National Energy Board ("NEB"). Terasen Gas pays both fixed and variable charges for use of the pipelines, which are recovered through rates paid by Terasen Gas' customers.

PEAK SHAVING ARRANGEMENTS

Terasen Gas incorporates peak shaving and gas storage facilities into its portfolio to:

1. Manage the load factor of baseload supply contracts throughout the year.
2. Eliminate the risk of supply shortages during a peak throughput day.
3. Reduce the cost of gas during winter months.
4. Balance daily supply and demand on the distribution system.

Terasen Gas' peak shaving and storage assets and contracts for 2009 include up to 30 PJ in storage capacity at various locations throughout British Columbia, Alberta and the Pacific Northwest of the United States. These facilities can deliver a maximum daily rate of 574 terajoules ("TJ") on a combined basis.

OFF SYSTEM SALES

Terasen Gas contracts pipeline capacity to ensure the Company's ability to meet its obligation to supply customers under all reasonable demand scenarios. The Company is in its thirteenth year of its off-system sales activities which allow for the recovery or mitigation of costs on unutilized supply and/or pipeline capacity. In 2007/2008, Terasen Gas marketed approximately 23.5 PJ of surplus gas and 43.7 PJ of excess pipeline capacity for a net pre-tax recovery of approximately $181.5 million. Through the Gas Supply Mitigation Incentive Plan (GSMIP) established with the BCUC, $1.1 million (pre-tax) of these benefits accrued to shareholders with the remainder flowing to customers in the form of reduced natural gas costs.

TRANSMISSION SERVICES

Terasen Gas serves Greater Vancouver and the Fraser Valley through a transmission and distribution system which connects to the Spectra and Northwest pipeline systems near Huntingdon, British Columbia. These connections provide access to gas supplies in Northeastern BC and Alberta and to storage facilities in the Pacific Northwest.

In the interior of British Columbia, Terasen Gas serves municipalities with several connections to the Spectra pipeline system. Communities in the East Kootenay region of B.C. are served through connections with TransCanada's B.C. system. The Terasen Gas Southern Crossing Pipeline between Yahk and Oliver is also connected to TransCanada's system and provides access to Alberta gas supplies.

In addition, Terasen Gas provides high-pressure transmission service to customers, such as TGVI and BC Hydro, who move natural gas from the Spectra or TransCanada systems across the Company's system to their own facilities or systems and to Northwest Natural Gas who moves gas from TransCanada across the Southern Crossing Pipeline for re-delivery to Northwest Pipeline at Huntingdon.

PROPERTIES

As of December 31, 2008, Terasen Gas had 2,800 kilometres of natural gas transmission pipeline and 37,000 kilometres of natural gas distribution pipeline in service. In addition to the pipelines, Terasen Gas owns properties and equipment utilized for service shops, warehouses, metering, compressors and regulating stations, as well as its main operations centre and head office in Surrey, B.C.

TITLE TO PROPERTIES

Terasen Gas' pipelines are constructed for the most part under highways and streets pursuant to permits or orders from the appropriate authorities, franchise or operating agreements entered into with municipalities and rights-of-way held directly or jointly with British Columbia Hydro and Power Authority ("B.C. Hydro"). Compressor stations and major regulator stations are generally located on freehold land, rights-of-way owned by Terasen Gas or properties shared with B.C. Hydro.

REGULATION

British Columbia Utilities Commission

Gas utilities in B.C. are subject to the regulatory jurisdiction of the BCUC which derives its powers from the Utilities Commission Act (British Columbia) (the "Act"). In addition to approving the rate base and new financings of Terasen Gas, the BCUC also approves the rates charged to customers. These rates are designed to recover the utilities' costs of providing service and to meet financial commitments of the Utility and are intended to allow the Utility an opportunity to earn a fair return on common equity. The BCUC has jurisdiction to regulate and approve the terms and conditions under which gas utilities provide service.

As part of the establishment of the rates which a gas utility charges its customers, the BCUC establishes a rate base, approves a capital structure with which to finance such rate base, and is responsible for setting a fair return on the debt and equity in the approved capital structure. Rate base is the aggregate of the depreciated cost of property, plant and equipment that is used or useful in serving the public, certain deferral accounts and a reasonable allowance for working capital. The fair return is established by determining the cost of individual components of the capital structure, including return on common equity, and weighting such costs to determine an aggregate return on rate base which is currently set at 35 percent. The rates that are established and the terms and conditions of service are contained in a schedule of tariffs. Before any tariff can be put into effect, it must be filed with the BCUC. The BCUC has jurisdiction to approve or refuse any amendment submitted for filing and to determine the rates which should be charged by a utility for its services. The BCUC is required to have due regard, among other things, to fixing rates that are not unjust or unreasonable. In fixing rates the BCUC must determine that such rates reflect a fair and reasonable charge for service of the nature and quality furnished by Terasen Gas to its customers and that such rates are sufficient to yield Terasen Gas a fair and reasonable compensation for its services and a fair return on its rate base.

The BCUC uses a future test year in the establishment of rates for a utility. Pursuant to this method, the Company forecasts the volume of gas that will be sold and transported, together with all of the costs of Terasen Gas (including the rate of return) that Terasen Gas will incur in the test year. Rates are fixed to permit Terasen Gas to collect all of its costs (including the rate of return) if the forecast sales and transportation volumes are achieved. The forecast sales volumes assume normal weather. Certain costs are fixed and will be incurred regardless of the actual volume of gas sold. Accordingly, if the actual volumes of gas sales are less than those forecast in the test year, Terasen Gas might not recover all of the fixed costs. Interest expense, taxes other than income taxes, depreciation and amortization, certain operations and maintenance costs, the portion of the cost of gas that is fixed such as demand charges or reservation fees, and the fixed portion of transportation costs have the effect of being virtually fixed costs.

Two mechanisms to ameliorate unanticipated changes in sales volumes, such as changes caused by weather, have been implemented specifically for Terasen Gas. The first relates to the recovery of all gas costs through deferral accounts which capture all variances (overages and shortfalls) from forecasts. Balances are either refunded to or recovered from customers via an application with the BCUC. The deferral accounts are called the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA"). The second mechanism seeks to stabilize delivery revenues from the residential and commercial classes through a deferral account that captures variances in the forecast versus actual customer use throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism ("RSAM"). In February 2001, the BCUC issued guidelines for quarterly calculations to be prepared to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas and to ensure that rate stabilization account balances are recovered on a timely basis.

Terasen Gas also has in place short-term and long-term interest rate deferral accounts to absorb interest rate fluctuations. The interest rate deferral accounts which were in place during 2008 effectively fixed the interest expense on short-term funds attributable to Terasen Gas' regulated assets at 5.00 percent during 2008. The effective fixed short-term interest rate for 2009 has been set at 4.25 percent.

In addition to an application for approval of interim and annual rate changes, the Company may apply from time to time to the BCUC for rate changes to give effect to the changes in costs beyond the control of the utility.

Important regulatory information, pertaining to decisions made by the BCUC with respect to Terasen Gas, is summarized in the following table.

Dollar amounts in millions *Years ended December 31*	2009	2008	2007	2006	2005
Approved rate base	$2,547	$2,510	$ 2,484	$ 2,516	$ 2,406
Deemed common equity component of total capital structure	35.01%	35.01%	35.01%	35.01%	33%
Allowed rate of return on common equity	8.47%	8.62%	8.37%	8.80%	9.03%

Terasen Gas' allowed ROE is determined annually based on a formula that resets annually off a forecast of 30 Year Canada Bonds plus a 3.90% risk premium when the forecast yield on 30 Year Canada Bond is 5.25%. The risk premium is adjusted annually by 75% of the difference between 5.25% and the forecast yield on 30 Year Canada Bonds. For 2008, the application of the ROE formula set Terasen Gas' allowed ROE at 8.62%, up from 8.37% in 2007. For 2009, the allowed ROE has been set at 8.47% for Terasen Gas

2008-2009 Performance-Based Rate Plan (PBR)

In July 2003, Terasen Gas received BCUC approval of a negotiated settlement for a 2004-2007 PBR. The PBR Settlement established a process for determining Terasen Gas' delivery charges and incentive mechanisms for improved operating efficiencies. The four-year agreement included incentives for Terasen Gas to operate more efficiently through the sharing of the benefits between Terasen Gas and its customers. The PBR Settlement included ten service quality measures designed to ensure Terasen Gas maintains adequate service levels. It also set out the requirements for an annual review process which will provide a forum for discussion between Terasen Gas and interested parties regarding its current performance and future activities.

Operation and maintenance costs and base capital expenditures were subject to an incentive formula reflecting increasing costs due to customer growth and inflation, less an adjustment factor based on 50 percent of inflation during the first two years of the PBR and 66 percent of inflation during the last two years. Base capital expenditure amounts are a function of customer numbers and projected customer additions. The PBR Settlement provides for a 50/50 sharing mechanism of earnings above or below the allowed return on equity beginning in 2004.

In 2007, Terasen Gas applied for an extension of the 2004-2007 PBR settlement agreement. The application requested approval to extend the existing settlement term for 2008-2009. On March 23, 2007, the BCUC approved the application as filed.

UNBUNDLING

Over the past several years, Terasen Gas, the BCUC and a number of interested parties have laid the groundwork for the introduction of natural gas commodity unbundling. On November 1, 2004, commercial customers of Terasen Gas became eligible to sign up to buy their natural gas commodity supply directly from third party suppliers. Terasen Gas continues to provide delivery of the natural gas. Approximately 80,000 commercial customers are eligible to participate in commodity unbundling. By December 31, 2008, 19,800 customers elected to participate in this program.

During 2006, the BCUC approved offering commodity supply choice to residential customers. The BCUC agreed to open a portion of the Province's residential natural gas market to competition, allowing homeowners to sign long-term fixed price contracts for natural gas with companies other than Terasen Gas starting in May 2007. Since November 2007 residential customers have had the option of remaining with Terasen Gas or signing with a marketer and receiving gas at the marketer's rate. Terasen Gas continues to provide delivery service to unbundled customers and delivery margins are not impacted by the migration of residential customers to alternative commodity suppliers. Approximately 748,000 residential customers are eligible to participate in commodity unbundling. At December 31, 2008, 115,500 customers had elected to participate in this program. Neither commercial nor residential unbundling has had a material effect on the delivery margins of Terasen Gas.

FRANCHISE AND OPERATING AGREEMENTS

Terasen Gas currently holds operating agreements with most of the incorporated municipalities in which it distributes gas in the Greater Vancouver and Fraser Valley service areas. The operating agreements are in force so long as the distribution lines of Terasen Gas are operative and do not contain any provision entitling the municipality to purchase the distribution system. No fees are payable by Terasen Gas under these operating agreements.

Terasen Gas currently holds franchise or operating agreements with most of the incorporated municipalities in which it distributes gas in the interior of British Columbia. The terms of these franchise agreements ranges from 10 to 21 years. While such franchise or operating agreements are in effect, the municipalities receive franchise fees of three per cent of the gross revenue from customers in the municipality. Historically, approximately one-quarter of these franchise agreements contained a provision to the effect that at the end of the term the municipality could purchase the distribution system within the municipality as a going concern and at a price equal to the fair value of the business undertaking. If the municipality did not exercise the right to purchase or grant a new franchise or operating agreement, gas utilities would be required under the Act to continue to provide service in the municipality unless the BCUC ordered otherwise. Terasen Gas no longer has any franchise agreements that contain right to purchase provisions. Some of those franchise agreements have expired and in some other cases, an arrangement was developed to enable the transfer of economic risks and rewards of ownership to the municipality, while allowing Terasen Gas to continue to operate within the municipality.

These arrangements have been entered into with five municipalities to date. In each of the transactions, Terasen Gas entered into an arrangement whereby the municipality leased Terasen Gas' gas distribution assets within the municipality's boundaries for a term of 35 years for an initial cash payment. Terasen Gas in turn entered into a 17 year operating lease with the municipality whereby Terasen Gas will operate the gas distribution assets. Terasen Gas has the option to terminate the lease of the assets to the municipality at the end of 17 years in exchange for a payment to the municipality equal to the depreciated value of the leased assets. As at December, 2008, Terasen Gas had entered into such arrangements involving a total value of $153 million, and the value of future transactions is not expected to be material.

OPERATING SUMMARY FOR TERASEN GAS

Dollar amounts in millions *Years ended December 31*	**2008**	2007	2006
Revenues			
Residential	**$ 1,014.1**	$ 922.0	$ 922.4
Commercial	**525.0**	475.9	463.6
Small industrial	**33.0**	34.1	41.7
Large industrial and other	**1.4**	1.9	2.2
Total natural gas sales revenue	**1,573.5**	1,433.9	1,429.9
Transportation	**71.3**	70.8	73.6
Other	**19.8**	19.9	21.8
Total natural gas revenue	**$ 1,664.6**	$ 1,524.6	$ 1,525.3
Volumes (PJs)[1]			
Residential	**78.5**	74.9	68.7
Commercial	**44.1**	42.3	38.4
Small industrial	**3.1**	3.4	3.8
Large industrial and other	**0.1**	0.2	0.2
Total natural gas sales volume	**125.8**	120.8	111.1
Transportation	**57.3**	62.3	62.3
Other	**39.6**	36.8	36.8
Total natural gas volume	**222.7**	222.4	210.2
Customers at year end			
Residential	**750,838**	742,882	733,598
Commercial	**81,012**	79,717	79,113
Small industrial	**284**	297	325
Large industrial and other	**33**	40	40
Transportation	**2,059**	2,041	1,956
	834,226	824,977	815,032
Customers statistics			
Average use per customer (GJs)			
Residential	**105**	101	94
Commercial	**544**	530	485
Average rate per GJ			
Residential	**$ 12.92**	$ 12.31	$ 13.42
Commercial	**$ 11.90**	$ 11.25	$ 12.07
Natural gas purchased (PJs)	**125.8**	120.8	111.1
Maximum day sendout (TJs) (including interruptible)	**1,402.0**	1,388.9	1,349.6
Approved rate base	**$ 2,510.2**	$ 2,484.4	$ 2,516.0
Degree days (Base 18°C)[2]			
Coastal – Actual	**3,043**	2,889	2,714
– Normal	**2,758**	2,726	2,765
Interior – Actual	**4,205**	3,904	3,753
– Normal	**3,842**	3,921	3,901

[1] *Volume statistics are stated in SI (metric) units*
[2] *A degree-day is approximately equal to 18 deg C minus the daily average temperature in the corresponding region. The normal period is based on a 20-year basis..*

SAFETY AND ENVIRONMENTAL PROTECTION

Although the operations of the Company regulated by the BCUC, Canadian federal, provincial and municipal governments share jurisdiction over matters affecting safety and the environment. As a result, the Company is subject to extensive federal, provincial and municipal regulations relating to the protection of the environment including, but not limited to, wildlife, water and land protection and the proper storage, transportation, disposal and release of hazardous and non-hazardous substances. In addition, both the provincial and federal governments have environmental assessment legislation, which is designed to foster better land-use planning through the identification and mitigation of potential environmental impacts of projects or undertakings prior to and after commencement.

These environmental considerations are best addressed within the context of a formal environmental management system ("EMS"). Terasen Gas has developed an EMS designed to manage the impact of its activities on the environment consistent with the guidelines of ISO 14001, an internationally recognized standard for environmental management systems. As part of its EMS, Terasen Gas is continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor environmental performance. The EMS system also includes environmental training requirements for our employees, environmental guidelines to minimize the impacts of our operations, as well as environmental compliance. Terasen Gas has external audits of its EMS conducted on five year cycle to ensure continued compliance with ISO 14001 standards.

The Company's senior executives are committed to ensuring Terasen Gas is an industry leader with respect to environmental protection and compliance with environmental policies. Health, safety and environmental issues and initiatives are reported regularly to Terasen Gas' senior executives.

Terasen Gas meets or exceeds legislative standards and environmental protection requirements with respect to its operations. Terasen Gas could be exposed to significant operational disruptions and environmental liability in the event of an accident involving natural gas. Terasen Gas has taken all reasonable and prudent steps to minimize its exposure in the case of a catastrophic event or environmental upset. The focus of its safety and environmental practices is to ensure reliable, cost effective, quality service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. For Terasen Gas, air emissions management is the main environmental concern primarily due to the uncertainties relating to emerging federal and provincial greenhouse gas regulations. While governmental policy direction is starting to unfold, it remains to be determined to what extent a greenhouse gas emissions cap will impact Terasen Gas. To mitigate this uncertainty, Terasen Gas participates in sectoral and industry groups to help develop the emerging regulation. In addition, Terasen Gas was an active participant in Canada's Voluntary Climate Change Challenge and Registry (VCR) and its successor, the Canadian Greenhouse Gas Challenge Registry.

British Columbia's recent updates to its energy plan and greenhouse gas reduction targets present risks and opportunities for Terasen. The recent Greenhouse Gas Reduction Targets Act (GGRTA) mandates province-wide reductions in greenhouse gases of 33% over 2007 levels. This is coupled with mandates for all new electricity generation to be net carbon neutral, and for British Columbia to be electrically self-sufficient by 2016.

These requirements place significant pressure on natural gas distribution, as its direct use in space and water-heating contributes to greenhouse gas emissions. Further, electricity that generally is produced from hydro sources has been given increased emphasis over natural gas for thermal applications. However, Terasen Gas continues to work with the provincial government to emphasize that efficient use of natural gas for thermal applications reduces strain on electrical grids, allowing for more efficient electricity use domestically, plus increased opportunity to export less emissions-intensive electricity to other jurisdictions.

Energy and emissions policy in British Columbia also presents a number of risks and opportunities. The policies have created incentives to expand deployment of renewable energy (such as biogas), and to expand our Energy Efficiency and Conservation program. Additionally, the introduction of the Carbon Tax Act improves the position of natural gas relative to other fossil energy, as the tax is based on the amount of carbon dioxide equivalent emitted per unit energy. Natural gas therefore has a lower tax rate than oil or coal products.

British Columbia is a participant in the Western Climate Initiative. This group, consisting of several states and provinces, plans to implement a cap-and-trade program to reduce greenhouse gas emissions. The program begins on January 1, 2012. At that time, Terasen Inc. expects to have one facility covered under this program: the Terasen Gas (Vancouver Island) Inc. transmission system. This facility will be required to reduce emissions to meet a declining cap on emissions, or to purchase emissions allowances to cover emissions over the capped amount. While allowance costs are based on market prices that have very little clarity at present, it appears likely that this facility will be a net purchaser of allowances over the near and medium term. Allowances will likely be issued to mirror the emission reduction mandate of the province, such that emissions will need to be reduced by 33% over 2007 amounts by 2020. Currently, Terasen Gas is not covered under this program.

The Company has asset retirement obligations as disclosed in the Notes to the 2008 Consolidated Financial Statements. However, liabilities with respect to these asset retirements obligations have not been recorded in the 2008 Consolidated Financial Statements as they could not be reasonably estimated.

Terasen Gas has detailed emergency preparedness plans in place to respond to natural disasters, accidents and emergencies, and regularly tests these plans in simulations involving employees and other emergency response organizations. The Company is also committed to monitor and assess its safety and environmental performance regularly. Terasen Gas incorporates safety performance measures into its employee compensation system, sets challenge levels and objectives for environmental performance, and conducts safety and environmental audits.

Compliance with environmental laws and regulations did not have a material effect on the capital expenditures, earnings or competitive position of Terasen Gas in 2008 and, based on current laws, facts and circumstances, is not expected to have a material effect in the future. Prudently incurred operating and capital costs, associated with complying with environmental laws and regulations, are generally recoverable in customer rates. Terasen Gas believes that it is materially compliant with environmental laws and regulations which are applicable to its operations.

Specialized Skills and Knowledge

The skills and knowledge needed to operate and maintain natural gas distribution systems are key to the Company's success. These skills are currently available, and Terasen Gas has placed considerable focus in succession planning on ensuring that these skills are preserved as the Company's workforce ages and retires.

Employees

Terasen Gas and its subsidiaries employed approximately 1,100 people as at December 31, 2008. The organized employees of Terasen Gas are represented by the International Brotherhood of Electrical Workers and the Canadian Office and Professional Employees Union under collective agreements which expire on March 31, 2011 and March 31, 2012, respectively.

Seasonality

Because of natural gas consumption patterns, the natural gas transmission and distribution operations of Terasen Gas normally generate higher net earnings in the first and fourth quarters and lower net earnings in the second quarter, which are offset by net losses in the third quarter

RISK FACTORS

Prospective investors in a particular offering of Securities by Terasen Gas should consider, in addition to information contained in the prospectus relating to that offering or in other documents incorporated by reference therein, the risks described below. Terasen Gas' key risk factors include, but are not limited to the following:

Regulation

Through the regulatory process, the BCUC approves the return on equity which Terasen Gas is allowed to earn, in addition to various other aspects of utility operations. In addition, the recovery of costs incurred in constructing and operating the gas utility is subject to the approval of the BCUC. Regulatory treatment that allows Terasen Gas to earn a fair risk adjusted rate of return comparable to that available on alternative, similar risk investments is essential for maintaining service quality as well as ongoing capital attraction and growth. Since 1994, subject to minor modifications, the allowed ROE has been set based on a formula linked directly to forecast 30 year Canada Bond yields which have steadily declined in recent years. Terasen Gas will be seeking changes to the current generic ROE adjustment mechanism and increases to deemed equity thickness to more fair and appropriate levels. The Company intends to file an application with the BCUC in the second quarter of 2009.

Terasen Gas' 2004-2007 PBR settlement agreement, which has been extended through 2009, includes incentive mechanisms that provide Terasen Gas with an opportunity to earn returns in excess of the allowed return on equity determined by the BCUC. Upon expiry of the settlement agreement, there is no certainty as to whether new negotiated settlements will be entered into, or what the terms of the new settlements might be.

Terasen Gas is currently preparing a rate application with anticipated filing with the BCUC in the second quarter of 2009. BCUC approval of rates for 2010, and for future years, will be required. There can be no assurance that the rate orders issued will permit the Company to recover all costs actually incurred and to earn the expected rate of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the Company, the undertaking or timing of proposed upgrades or expansion projects, the issue and sale of securities, ratings assigned by rating agencies, and other matters which may, in turn, negatively impact the Company's results of operations or financial position.

It is essential that the Company maintain good relationships with its various regulators and customer representatives.

Operations and the Environment

The Company is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety. The costs arising from compliance with such laws, regulations and guidelines may be material to the Company. The process of obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, contentious and expensive. Potential environmental damage and costs could arise due to a variety of events and could be material if an event happened. However, there can be no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs may have a material effect on the business, results of operations, financial condition and prospects of the Company.

The Company is exposed to environmental risks that owners and operators of properties in British Columbia generally face. These risks include the responsibility of any current or previous owner or operator of a contaminated site for remediation of the site, whether or not such person actually caused the contamination. In addition, environmental and safety laws make owners, operators and persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval. The Company has not been notified of any such regulatory action in regard to the operation or occupation of its facilities. However, it is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety laws could also lead to significant increases in costs to the Company.

The Company is exposed to various operational risks, such as pipeline leaks; accidental damage to, or fatigue cracks in mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas, which could result in significant operational disruptions and/or environmental liability. The Company believes it has taken all reasonable and prudent steps to minimize its exposure in the case of a catastrophic event or environmental upset. The Company conducts its operations utilizing an Environmental Management System which specifies impacts, control measures and audit protocols. The Company maintains comprehensive facility risk assessment, pipeline integrity management and damage prevention programs and pipeline security systems as preventive measures to mitigate the risk of a pipeline failure or other loss of system integrity. These programs are intended to reduce both the likelihood and severity of the business interruption and/or environmental liability that could result from a pipeline failure or loss of integrity.

A major natural disaster, such as an earthquake affecting the Company's service area could severely damage Terasen Gas' natural gas transmission and distribution systems. The Company has detailed emergency preparedness plans in place to respond to natural disasters, accidents and emergencies, and regularly tests these plans in simulations involving employees and other emergency response organizations. The Company also has an insurance program which provides coverage for business interruption, liability and property damage, although the coverage offered by this program is limited. In the event of a large uninsured loss caused by a natural disaster, the Company would apply to the BCUC for recovery of these costs through higher rates. However, there is no assurance that the BCUC will approve any such application.

The actions necessary to abandon pipeline systems at the eventual end of their useful lives have not been defined and the costs of these actions may not be fully recovered in rates or tolls. Until such time as the specified requirements of abandonment and the funding mechanism for the eventual recovery of negative salvage is determined, the Company, like other Canadian pipeline systems, makes no provision for these amounts.

Terasen Gas' natural gas transmission and distribution systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the Company determines expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures which the Company believes are necessary to maintain, improve and replace their assets; the failure by the Company to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures despite maintenance programs could have a material effect on the Company.

The Company continually develops capital expenditure programs and assesses current and future operating and maintenance expenses that will be incurred in the ongoing operation. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. If actual costs exceed regulatory-approved capital expenditures, it is uncertain as to whether such additional costs will receive regulatory approval for recovery in future customer rates. The inability to recover these additional costs could have a material effect on the financial condition and results of operations of the Company. See "Regulation" for further discussion on regulatory risk.

COMPETITIVENESS

Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, because electricity prices in British Columbia continue to be set based on the historical average cost (primarily hydro-electric dams) of production, rather than based on market forces, they have remained low compared to market priced electricity. As a result, the price of electricity for residential customers in British Columbia is now only marginally higher than for natural gas. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future.

The Company employs a number of tools to reduce its exposure to natural gas price volatility. These include purchasing gas for storage and adopting hedging strategies, which include a combination of both physical and financial transactions, to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive against electric rates. Activities related to the hedging of gas prices are approved by the BCUC and gains or losses accrue entirely to customers.

If natural gas pricing becomes uncompetitive with electricity prices or the price of other forms of energy, the Company's ability to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the Company's cost of service in rates charged to customers.

In 2008 the Government of British Columbia introduced changes to energy policy including greenhouse gas emission reduction targets and a consumption tax on carbon based fuels that impact the competitiveness of natural gas versus non-carbon based energy sources or alternate energy sources. It did not, however, introduce carbon tax on imported electricity generated through the combustion of carbon based fuels. The future impact of these changes in energy policy may have a material impact on the competitiveness of natural gas relative to other energy sources.

There can be no assurance that the current regulatory-approved flow through mechanisms in place allowing for the flow through of the cost of natural gas will continue to exist in the future. An inability of the Company to flow through the full cost of natural gas could materially affect the Company's results of operations, financial position and cash flows.

LABOUR RELATIONS

Approximately 75% of the employees of the Company are members of labour unions that have entered into collective bargaining agreements with the Company. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by the Company. The Company considers its relationships with its labour unions to be positive but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have an adverse effect on the results of operations, cash flow and net income of the Company.

IMPACT OF CHANGES IN ECONOMIC CONDITIONS

Typical of utilities, economic conditions in the Company's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. New customer additions at the Company are typically a result of population growth and new housing starts, which are affected by the state of the provincial economy. The Company is also affected by changes in trends in housing starts from single family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. Housing starts in 2008 were more moderate compared to the previous number of years, and the growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. Higher energy prices can dampen economic activity and reduce consumption by customers. Natural gas and crude oil prices are closely correlated with natural gas and crude oil exploration and production activity in certain of the Company's service territories. The level of these activities can influence energy demand.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of Terasen Gas, including various mitigating measures approved by regulators, helps to reduce the impact that lower energy demand, associated with poor economic conditions, may have on the Company's earnings. However, a severe and prolonged downturn in economic conditions could materially affect the Company despite regulatory measures available for compensating for reduced demand. For instance significantly reduced energy demand in the Company's service territories could reduce capital spending which would in turn impact rate base and earnings growth. Despite current depressed economic conditions, which are expected to continue during 2009, the Company does not anticipate any significant decrease in capital spending in 2009.

NATURAL GAS SUPPLY

The Company is dependent on a limited selection of pipeline and storage providers, particularly in the Vancouver and Fraser Valley areas where the majority of the Company's natural gas distribution customers are located. Regional market prices have been higher from time to time than prices elsewhere in North America as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in B.C. and the U.S. Pacific Northwest.

In addition, the Company is critically dependent on a single source transmission pipeline. In the event of a prolonged service disruption on the Spectra transmission system, the Company's residential customers could experience outages, thereby affecting revenues and incurring costs to safely relight customers.

CAPITAL RESOURCES AND LIQUIDITY

The Company's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by rating agencies, adequate allowed rates of return on equity granted by the BCUC and general economic conditions. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) will not be sufficient to fund the repayment of all outstanding liabilities when due as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and to repay existing debt.

Generally, the Company is subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings impact the level of credit risk spreads on new long-term debt issues and on the Company's credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the Company's finance charges. Also, a significant downgrade in the Terasen Gas' credit ratings could trigger margin calls and other cash requirements under Terasen Gas' natural gas purchase and natural gas derivative contracts. The Company's corporate investment-grade credit ratings were confirmed and maintained during the year and the Company does not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the current global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria which may result in changes to credit rating practices and policies.

The recent and expected continued volatility in the global financial and capital markets will likely increase the cost of and affect the timing of issuance of long-term capital by the Company in 2009. The cost of borrowing is expected to increase as new long-term debt is expected to be issued at higher rates due to an increase in credit spreads. Due to the regulated nature of the Company's operations, the expected higher cost of borrowing is eligible to be recovered in future customer rates.

To help mitigate liquidity risk, Terasen Gas has secured multi-year committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

Transition to International Financial Reporting Standards

The Accounting Standards Board of the Canadian Institute of Chartered Accountants has announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, effective January 1, 2011. IFRS will require increased financial statement disclosure as compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by the Company. The Company is currently considering the impact a conversion to IFRS would have on its future financial reporting. Additional information on the Company's transition to IFRS is provided in the "Future Accounting Pronouncements" section of Terasen Gas' December 31, 2008 MD&A.

Interest Rates

The allowed returns on equity for the Company are determined by formulae that result in lower allowed ROEs if forecast long-term Canada bond yields decline. The Company's exposure to short-term interest rates are covered by regulatory deferral accounts, however it is exposed to changes in short-term interest rates through debt on non-regulated operations.

Employee Future Benefits

The Company maintains defined benefit pension plans and there is no certainty that the pension plan assets will be able to earn the assumed rate of returns. Market driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed return on the assets causing material changes in the pension expense and funding requirements. The regulated operation of the Company currently has a deferral mechanism which allows for deferral of the pension expense that is approved for recovery in rates and the actuarial pension expense. Net pension expense is impacted by, among other things, the amortization of experience and actuarial gains or losses and expected and actual return on plan assets.

Market driven changes impacting other pension assumptions, including the assumed discount rate, may also result in future contributions to pension plans that differ significantly from current estimates as well as causing material changes in pension expense. There is also measurement uncertainty associated with pension expense, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation due to measurement uncertainty inherent in the actuarial valuation process.

COUNTERPARTY CREDIT RISK

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Company is also exposed to significant credit risk on physical off-system sales. Terasen Gas deals with high credit quality institutions in accordance with established credit approval practices. Due to recent events in the financial markets including significant international government intervention in the banking systems and financial markets the Company has further limited the financial counterparties that it transacts with and reduced available credit to, or taken additional security from, the physical off-system sales counterparties it deals with. To date the Company has not experienced any counterparty defaults and does not expect any counterparties to fail to meet their obligations however, the credit quality of counterparties, as recent events have indicated, can change rapidly.

FIRST NATIONS LAND

The Company provides service to customers on First Nations lands and maintains gas transmission and distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Company is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as the Company. However, there can be no certainty that the settlement process will not adversely affect the business of the Company.

DIVIDENDS

In 2008, Terasen Gas paid $100.0 million in dividends to its parent Terasen Inc., compared with $110.9 million in 2007.

As part of its approval of the acquisition of Terasen by Fortis, the BCUC imposed a number of conditions intended to ring-fence Terasen Gas from its parent company. These restrictions include a prohibition on the payment of dividends unless Terasen Gas has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. Terasen Gas' dividend policy is intended to ensure that Terasen Gas maintains at least as much common equity as that deemed by the BCUC for rate-making purposes.

DESCRIPTION OF CAPITAL STRUCTURE

The Company is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value. As at December 31, 2008, 59,591,732 common shares were issued and outstanding. Terasen Gas is a wholly-owned indirect subsidiary of Fortis Inc.

CREDIT RATINGS

Securities issued by Terasen Gas are rated by Dominion Bond Rating Service Limited ("DBRS") and Moody's Investors Service Inc. ("Moody's"). The ratings assigned to securities issued by Terasen Gas are reviewed by these agencies on an ongoing basis. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. DBRS rates debt instruments by rating categories ranging from AAA which represents the highest quality of securities, to D which represents the lowest quality of securities rated. Moody's rates debt instruments by rating categories ranging from Aaa which represents the highest quality of securities to C which represents the lowest quality of securities.

According to the Moody's rating system, debt securities rated A are considered to possess many favourable investment attributes and are to be considered as upper medium grade obligations. Factors giving security to principal and interest are considered adequate but elements may be present which suggest a susceptibility to impairment some time in the future. Moody's applies numerical modifiers (1, 2 and 3) in each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its rating category.

According to the DBRS rating system, debt securities rated A are of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than with AA related entities. While a respectable rating, entities in the A category are considered to be more susceptible to economic conditions and have greater cyclical tendencies than higher rated companies. For short term debt a rating of R-1 is of prime credit quality. Any qualifying negative factors which exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry. "High" or "Low" are used to indicate the relative standing of a credit within a particular rating category. The lack of one of these designations indicates a rating which is essentially in the middle of the category.

The credit ratings accorded to the rated securities are not recommendations to purchase, hold or sell the rated securities inasmuch as those ratings do not comment as to market price or suitability for a particular investor. There is no assurance that those ratings will remain in effect for any given period of time or that those ratings will not be revised or withdrawn entirely by those rating agencies in the future if, in their judgment, circumstances so warrant.

The table below summarizes the ratings assigned to the Company's various securities. The DBRS rating is as of May 20, 2008 and the Moody's rating is as of July 17, 2008.

Credit Ratings	DBRS	Moody's
Commercial paper	R-1 (Low)	
Unsecured long-term debt	A	A3
Secured long-term debt	A	A2

After reassessing its relationship with Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies (Canada) Corporation (S&P), Terasen Gas decided early in 2004 to discontinue the engagement of S&P to provide credit ratings on the debt of Terasen Gas. Terasen Gas believes the credit ratings issued by Moody's and DBRS will be sufficient to service the requirements of creditors and maintain the Company's access to capital. S&P continues to provide an unsolicited rating on Terasen Gas' outstanding debt based on publicly available information. As of December 17, 2008, Terasen Gas' unsecured long-term debt was rated A by S&P.

S&P rates debt instruments by rating categories ranging from AAA which represents the highest quality of securities, to D which represents the lowest quality of securities rated.

According to the S&P rating system, debt securities rated A exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a plus (+) or minus (-) after a rating indicates the relative standing within the particular rating category.

MARKET FOR SECURITIES

Terasen Gas' shares are not listed for trading. Terasen Gas is a wholly-owned indirect subsidiary of Fortis Inc.

In May 2008, Terasen Gas issued $250.0 million of 30-year medium term note debentures at an interest rate of 5.80%.

In October 2007, Terasen Gas issued $250 million of 30-year medium term note debentures at an interest rate of 6.00%.

DIRECTORS AND OFFICERS

The names, years first elected as directors, province of residence, positions and principal occupations of the directors and officers of the Company as at February 17, 2009 are set out as follows. Each director was duly appointed to serve until the next annual meeting or until his or her successor is elected or appointed.

DIRECTORS

NAME, RESIDENCE AND YEAR FIRST BECAME A DIRECTOR	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
Harold Calla(1) British Columbia, Canada 2007	Chair of the First Nation Financial Management Board.
Brenda Eaton(1) British Columbia, Canada 2009	Chair, BC Housing Management Commission since June 2005; prior thereto Deputy Minister to the Premier (British Columbia).
Ida J. Goodreau(2) British Columbia, Canada 2007	President and Chief Executive Officer of Vancouver Coastal Health Authority.
R.L.(Randy) Jespersen British Columbia, Canada 2005	President & CEO of the Company since May 2007 and President of the Company since April 2002; additionally Chairman of the Board of the Company May 2006 to May 2007
Harry McWatters(1) British Columbia, Canada 2007	President, Vintage Consulting Group; prior thereto President & CEO of Sumac Ridge Estate Wine Group.
H. Stanley Marshall(2)(3) Newfoundland and Labrador, Canada 2007	President & Chief Executive Officer of Fortis Inc.
Barry V. Perry(1) Newfoundland and Labrador, Canada 2007	Vice President, Finance and Chief Financial Officer of Fortis Inc. since January, 2004; prior thereto Vice President and Chief Financial Officer of Newfoundland Power.
Linda S. Petch(2) British Columbia, Canada 2007	President of Petch & Associates Management Consultants Ltd.
David R. Podmore(1) British Columbia, Canada 2007	President & Chief Executive Officer of Concert Properties Ltd.
John C. Walker(2) British Columbia, Canada 2007	President & CEO of FortisBC Inc. since April 2005; prior thereto President & CEO of Fortis Properties Corporation from January 1996 to March 2005.

1. Member of the Audit & Risk Committee.
2. Member of the Governance & Human Resources Committee.
3. Chairman of the Board.

OFFICERS

NAME, POSITION AND RESIDENCE	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
R.L. (Randy) Jespersen President and CEO British Columbia, Canada	President & CEO of the Company since May 2007 and President of the Company since April 2002; additionally Chairman of the Board of the Company May 2006 to May 2007.
Dwain A. Bell Vice President, Distribution British Columbia, Canada	Vice President, Distribution of the Company since January 2005; prior thereto, General Manager, Distribution Operations from January 2004 to December 2004; prior thereto, Director, Operations of Terasen Gas (Vancouver Island) Inc. since January, 2002.
David C. Bennett Vice President, General Counsel and Corporate Secretary British Columbia, Canada	Vice President, General Counsel and Corporate Secretary of the Company since May 2007 and Vice President, Regulatory Affairs, General Counsel and Corporate Secretary of FortisBC Inc. since February 2007; prior thereto General Counsel and Corporate Secretary of FortisBC Inc. from May 2005 to February 2007 and Corporate Counsel and Assistant Corporate Secretary from October 2004 to May 2005; prior thereto Associate lawyer, Pushor Mitchell LLP, April 2003 to October 2004.
Roger Dall'Antonia Vice President, Corporate Development and Treasurer British Columbia, Canada	Vice President, Corporate Development and Treasurer of the Company since November, 2007; prior thereto Vice President, Treasury and Investor Relations of Versacold Income Fund July 2006 to November 2007; prior thereto Vice President, Treasurer of the Company from March 2006 to July 2006 and Assistant Treasurer of Terasen Inc. July 2004 to March 2006; prior thereto, financial consultant since May 2003 to July 2004.
Cynthia Des Brisay Vice President, Gas Supply & Transmission British Columbia, Canada	Vice President, Gas Supply & Transmission of the Company since May, 2008; prior thereto, Director, Business Development & Resource Planning from January 2004 to April 2008; and prior thereto Business Leader, Project Development since February 2000.
Jan A. Marston Vice President, Gas Supply and Transmission British Columbia, Canada	Vice President, Human Resources & Operations Governance since May, 2008; prior thereto Vice President, Gas Supply & Transmission of the Company since January 2005; prior thereto, Vice President, Marketing since January 2002.
Robert M. Samels Vice President, Business Services and CIO British Columbia, Canada	Vice President, Business Services and CIO of the Company since January 2004; prior thereto, Vice President, Information Technology and CIO since September 2001.
Douglas L. Stout Vice President, Marketing and Business Development British Columbia, Canada	Vice President, Marketing & Business Development of the Company since January 2005; prior thereto, Vice President, Gas Supply & Transmission since December 2001.

Name, Position and Residence	**Principal Occupation for the Five Preceding Years**
Scott A. Thomson Vice President, Regulatory Affairs and Chief Financial Officer British Columbia, Canada	Vice President, Regulatory Affairs and Chief Financial Officer of the Company since May 2007; prior thereto, Vice President and Chief Financial Officer of the Company since December 2005; prior thereto, Vice President, Finance and Regulatory Affairs since February 2003.
Debra G. Nelson Assistant Corporate Secretary British Columbia, Canada	Assistant Corporate Secretary of the Company since November 1994 and additionally Manager, Corporate Compliance and Secretariat, Terasen Inc. since January, 2005.

LEGAL PROCEEDINGS

The Company is disputing a $7.0 million assessment of B.C. Social Service Tax representing additional provincial sales tax and interest on the Southern Crossing Pipeline, which was completed in 2000. The amount was paid in full in 2006 to avoid the accrual of further interest and has been included in other assets. The matter is currently under appeal to the Supreme Court of British Columbia.

During the year the Company reached a settlement with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of retroactive amending Quebec tax legislation. In August 2008, the Company made payments of approximately $12.7 million to settle the tax liability. As a result of the tax settlement, an earnings benefit of $5.6 million was recorded during 2008.

A number of claims and lawsuits seeking damages and other relief are pending against the Company. Management is of the opinion, based upon information presently available, that it is unlikely that any liability, to the extent not provided for through insurance or otherwise, would be material in relation to the Company's December 31, 2008 consolidated financial statements.

REGISTRAR, TRANSFER AGENT AND TRUSTEE

CIBC Mellon Trust Company is the registrar and transfer agent and trustee for the Company's unsecured debentures and purchase money mortgages. Transfers of these securities may be effected at CIBC Mellon Trust Company's offices in the cities of Vancouver, Toronto or Montreal.

MATERIAL CONTRACTS

The Company has not entered into any material contracts subsequent to January 1, 2002 that are outside the ordinary course of business.

INTERESTS OF INSIDERS IN MATERIAL TRANSACTIONS

In the past three years or current financial year, no insiders of Terasen Gas have been involved in any material transactions with the Company, nor do they have any existing or potential material conflicts of interest with the Company or any of its subsidiaries.

The Company paid $8.5 million in 2008 (2007 – $8.5 million) to Terasen for management services.

The Company received $3.3 million in 2008 (2007 – $4.1 million) from TGVI, a company under common control, for transporting gas through the Company's pipeline system.

The Company paid approximately $47.0 million during the year ended December 31, 2008 (2007 – $45.2 million) for customer care and billing services to a limited partnership. The Company's parent, Terasen, holds a 30% interest in the limited partnership and jointly controls it. The Company is committed to pay approximately $43.6 million as base contract fees for 2009.

The Company charged companies under common control $6.6 million in 2008 (2007 – $6.1 million) for management services.

INTERESTS OF EXPERTS

Terasen Gas' consolidated statements of financial position have been audited by Ernst & Young LLP, Chartered Accountants, of Vancouver, British Columbia. Ernst & Young LLP were appointed the auditors of Terasen Gas on July 26, 2007. The auditors, appointed by the shareholder, examined the consolidated financial statements in accordance with Canadian generally accepted auditing standards to enable them to express an independent opinion on the consolidated financial statements. The Company is not aware of any direct or indirect interests of Ernst & Young LLP, or any of the individuals involved in preparing the independent opinion, in Terasen Gas or any of its subsidiaries.

EXECUTIVE COMPENSATION

The Company's Statement of Executive Compensation is attached as Schedule "A".

INDEBTEDNESS OF EXECUTIVE OFFICERS, DIRECTORS, AND EMPLOYEES

The following table sets forth details of the aggregate indebtedness of all executive officers, directors, and employees and former executive officers, directors and employees outstanding at February 17, 2009 to the Company, other than routine indebtedness.

Aggregate Indebtedness		
Purpose	**To the Corporation or its Subsidiaries**	**To Another Entity**
Employee Share Purchase Plan	$162,650.90	Nil

The following table sets forth details of the indebtedness of the Directors and Executive Officers of the Company under the Employee Share Purchase Plan ("ESPP"). ESPP loans are interest free and are repayable within one year through regular payroll deductions. There is no indebtedness to the Company by executive officers, directors, employees for purposes other than indebtedness under the Employee Share Purchase Plan.

Indebtedness of Directors and Executive Officers under the Employee Share Purchase Program					
Name and Principal Position	**Involvement of Corporation or Subsidiary**	**Largest Amount Outstanding During 2008 $**	**Amount Outstanding as at January 31, 2009 ($)**	**Financially Assisted Securities Purchased During 2008 (#)**	**Security for Indebtedness**
Jan A. Marston, Vice President, Human Resources and Operational Governance	Terasen Gas as Lender	24,000	2,607	846	Securities Purchased

Robert M Samels, Vice President, Business Services and CIO.	Terasen Gas as Lender	14,998	8,652	593	Securities Purchased
Cynthia Des Brisay, Vice President, Gas Supply and Transmission	Terasen Gas as Lender	3,500	1,211	127	Securities Purchased
Dwain Bell, Vice President, Distribution	Terasen Gas as Lender	12,676	-	-	-

ADDITIONAL INFORMATION

Additional financial information is provided in Terasen Gas' Consolidated Financial Statements for the year ended December 31, 2008 and Management's Discussion and Analysis dated February 6, 2009 for the year ended December 31, 2008.

Additional information relating to Terasen Gas Inc. can also be found on SEDAR at www.sedar.com.

SCHEDULE A - EXECUTIVE COMPENSATION

A. COMPENSATION DISCUSSION & ANALYSIS

The Company's executive compensation program is designed to provide competitive levels of compensation, a significant portion of which is dependent upon individual and corporate performance and contribution to increasing shareholder value. The Committee recognizes the need to provide a total compensation package that will attract and retain qualified and experienced executives as well as align the compensation level of each executive to that executive's level of responsibility. The objectives of base salary are to recognize market pay, and acknowledge competencies and skills of individuals. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of Terasen Gas. Long-term incentive plans focus executives on sustained shareholder value creation.

The objectives of executive compensation practices at Terasen Gas are specifically designed to:

1. attract and gain sustainable commitment from senior management;
2. motivate performance by tying incentive compensation to the achievement of specific measures of financial and operating performance;
3. foster identification with shareholder interest through equity-based compensation; and
4. recognize other multiple stakeholder interests including those of customers and employees

Competitive Positioning

As a general policy, Terasen Gas establishes base and incentive compensation targets so as to compensate executives and in particular, each person who served as the Chief Executive Officer or Chief Financial Officer during the most recently completed financial year and the three most highly compensated executive officers of the Company during the most recently completed financial year (the "Named Executive Officers" or "NEOs") at a level generally equivalent to the median of practice among a broad reference group of approximately 200 Canadian commercial industrial companies. For clarity, this reference group does not include organizations in the financial service and broader public sectors. It does include organizations from the energy, mining and manufacturing sectors. This reference group is formally reviewed as part of the triennial review of executive compensation policy.

Base salaries for the NEOs are reviewed by the Governance and Human Resource Committee (the "Committee") and established annually in the context of total compensation from this reference group as a comparative measure.

Actual compensation will vary based on the performance of the executive relative to the achievement of goals and objectives. The NEOs are rewarded for performance through the following elements of compensation:

Compensation Element *(Eligibility)*	Description	Compensation Objectives
Annual Base Salary and Annual Incentive		
Annual Base Salary *(all NEOs)*	Salary is a market-competitive, fixed level of compensation.	Retain and attract highly qualified leaders ; Motivate strong business performance
Annual Incentive *(all NEOs)*	Combined with salary, the target level of annual incentive provides market-competitive total cash opportunity. Annual incentive payout depends on individual and corporate performance. Lower performers receive smaller incentive payouts, while higher performers receive larger incentive payouts.	Retain and attract highly qualified leaders by incenting and rewarding performance
Long-term equity based incentive		
Stock Options *(all NEOs)*	Equity grants are made in the form of stock options for Common Shares of Fortis. The amount of annual grant will be dependent on the level of the executive and their current share ownership levels. Planned grant value is converted to the number of shares granted by dividing the planned value by the pre-determined, formulaic planning price. Options vest over a 4 year period. Full eligibility for the stock option award is dependent upon the executive meeting share ownership levels of 300% of salary for the President and CEO and 150% of base salary for all other NEOs.	Retain and attract highly qualified leaders ; Motivate strong business performance; Align executive and investor interests; Balance compensation for short and long-term strategic results
Pension and Savings Plan		
Defined Benefit Pension Plan *(certain NEOs)*	Payout upon retirement based on the number of years of credited service and actual pensionable earnings.	Retain highly qualified leaders
RRSP *(certain NEOs)*	Contribution to a registered retirement savings plan equal to 6.5% of a member's base salary which is matched by the member up to the maximum contribution limit allowed by the Canada Revenue Agency.	Retain highly qualified leaders
Defined Contribution SERP *(certain NEOs)*	Accrual of 13% of base salary and annual incentive in excess of the Canada Revenue Agency limit. At time of retirement, paid in one lump sum or in equal payments over 15 years.	Retain highly qualified leaders
Employee Savings Plan *(all employees and NEOs)*	Contributions of 3% of base salary directed to a registered or non registered savings plan.	Retain highly qualified leaders

Annual Base Salary

Base salaries paid to the Company's NEOs are determined by the Board upon recommendation by the Committee and are established annually in the context of total compensation and by reference to the range of salaries paid at approximately the median of the salaries paid to executives of comparable Canadian commercial industrial companies.

Annual Incentive

NEOs participate in an annual incentive plan which provides for annual cash bonuses which are determined by way of an annual assessment of corporate and individual performance in relation to targets approved by the Board of Directors upon recommendation by the Committee. The Company's annual earnings must reach a minimum threshold level before any payments are made.

The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of the Company.

Corporate performance is determined with reference to the performance of the Company relative to weighted targets in respect of financial performance, customer, key processes, employee, and public safety. Individual measures weightings range from 5 to 30% and results can be objectively measured. The measures are quite similar to recent years with the target/challenge levels incenting improvement over our own historical performance as well as against our peers where appropriate.

The net earnings target for the gas segment is the "Gate" which must be met or exceeded in order for any incentive payments to be made. The measurable key performance targets for 2008 included the following:(i) projected gas segment earnings (ii) O&M per customer; (iii) base capital; (iv)customer satisfaction measured by quarterly customer surveys; (v) credit and collections is to have our bad debt experience at a set target of billed revenues; (vi) customer additions; (vii) employee injuries and vehicle accidents are set based on performance with our peer companies in the Canadian Gas Association and with Terasen Gas' three year historical average;(viii) wellness targets for the employee is set lower than the previous 3-year historical average; and (ix) public safety is based on those public safety service quality indicators included Terasen Gas' performance based rate settlement. It is the Company's belief that the above noted targets have been reached in 2008.

A target incentive award, based on each participant's level of responsibility is set and communicated to each participant annually. Scores for company performance measures are contained in a scorecard and an overall annual result is determined. The executive compensation program places a significant portion of compensation at risk through the annual incentive plan.

Individual performance is determined with reference to individual contribution to corporate objectives, elements of which are subjective. For the President and Chief Executive Officer, 70% of the annual cash bonus is based on corporate targets and 30% is based upon personal targets. For each of the other NEOs, 50% of the annual cash bonus is based upon corporate targets and 50% is based upon personal targets. At the discretion of the Board of Directors, executives may be awarded up to an additional 50% of target incentive pay in recognition of exceptional performance contributions.

Long term incentives are granted to align executives' interests with shareholders interests in increasing shareholder value. The program currently used by Terasen is the Fortis Inc. 2006 Stock Option Plan.

Description of this plan is set out below:

2006 Stock Option Plan

The 2006 Stock Option Plan was approved by the shareholders of Fortis Inc. on 2 May 2006 for purposes of granting options in the common shares of Fortis (the "Common Shares') to certain eligible persons, which includes the Company's NEOs (the "Eligible Persons") in order to encourage increased share ownership by key employees as an incentive to maximize shareholder value. The directors of Terasen Gas are not eligible to participate in the Fortis Inc. 2006 Stock Option Plan (the "2006 Stock Option Plan"). No options are granted under the 2006 Stock Option Plan if, together with any other security based compensation arrangement established or maintained by Fortis, such granting of options could result, at any time, in (a) the number of Common Shares issuable to insiders of Fortis, at any time, exceeding 10% of the issued and outstanding Common Shares and, (b) the number of Common Shares issued to insiders of Fortis, within any one (1) year period, exceeding 10% of the issued and outstanding Common Shares.

The 2006 Stock Option Plan is administered by the Human Resources Committee of Fortis Inc. Pursuant to the 2006 Stock Option Plan, the determination of the exercise price of options is made by the Human Resources Committee at a price not less than the volume weighted average trading price of the Common Shares of Fortis determined by dividing the total value of the Common Shares traded on the TSX during the last five (5) trading days immediately preceding the date by the total volume of the Common Shares traded on the TSX during such five (5) trading days. Options may not be amended to reduce the option price. The Human Resources Committee determines: (i) which Eligible Persons are granted options; (ii) the number of Common Shares covered by each Option grant; (iii) the price per share at which Common Shares may be purchased; (iv) the time when the Options will be granted; (v) the time when the options will vest; and (vi) the time at which the options will be exercisable (up to seven (7) years from the date of grant).

Options granted under the 2006 Stock Option Plan are personal to the Eligible Person and not assignable, other than by testate succession or the laws of decent and distribution. In the event that a person ceases to be an Eligible Person, the 2006 Stock Option Plan will no longer be available to such person. The grant of options does not confer any right upon an Eligible Person to continue employment or to continue to provide services to Terasen Gas.

If the term of an option granted pursuant to the 2006 Stock Option Plan, held by an Eligible Person, expires during a blackout period (being a period during which the Eligible Person is prohibited from trading in the securities of Fortis pursuant to securities regulatory requirements or Fortis's written policies then applicable), then the term of such option or unexercised portion thereof shall be extended and shall expire ten (10) business days after the end of the blackout period.

Options granted pursuant to the 2006 Stock Option Plan have a maximum term of seven (7) years from the date of grant and the options will vest over a period of not less than four (4) years from the date of grant, provided that no option will vest immediately upon being granted. Options granted pursuant to the 2006 Stock Option Plan will expire no later than three (3) years after the termination, death or retirement of an Eligible Person.

Eligible Persons are granted options based on salary levels. In 2008, the President and Chief Executive Officer of the Company was granted an option entitling him to purchase that number of Common Shares of Fortis Inc. having a market value at the time of grant equal to 300% of his base salary. Each of the other NEO's were granted an option entitling each NEO to purchase that number common shares having a market value at the time of grant equal to 150% of such NEO's annual base salary.

The 2006 Stock Option Plan provides that not withstanding provisions in the plan to the contrary, no option maybe amended to reduce the option price below the option price as of the date the option is granted.

Pension Plans

See "Executive Compensation – Pension Plan Benefits".

Employee Savings Plan

Terasen Gas contributes an amount equal to 3% of monthly base salary. These contributions may be directed to an RRSP, spousal RRSP, a non-registered savings plan or any combination. This plan is provided to all eligible employees of Terasen Gas including NEOs.

B. SUMMARY COMPENSATION TABLE

The following table sets forth the compensation information for the financial years indicated below for the NEOs:

Name and principal position	Year	Salary ($)	Option-based awards ($)[1]	Annual incentive plans[2]	Pension value ($) [3]	All other compensation ($)[4]	Total compensation ($)
R.L. (Randy) Jespersen President, and CEO Terasen Gas Inc.	2008	440,000	222,273	300,000	688,000	27,075	1,677,348
S.A. Thomson Vice President, Finance and Regulatory and CFO Terasen Gas Inc.	2008	275,000	69,458	175,000	44,000	15,764	579,222
D.L. Stout Vice President, Marketing and Business Development Terasen Gas Inc.	2008	254,000	64,165	145,000	39,000	16,570	518,735
J.A. Marston Vice President, Human Resources and Operations Governance Terasen Gas Inc.	2008	249,000	62,889	138,000	38,000	23,914	511,803
R.M. Samels Vice President, Business Services and CIO Terasen Gas Inc.	2008	218,000	55,064	115,000	169,000	21,536	578,600

Compensation and Benefits

The following outlines the terms of the compensation and benefits as outlined in the employment agreements for Messrs. Jespersen, Thomson, Stout, Samels and Ms. Marston.

The Annual Base Salary paid to the NEO shall, for the purpose of establishing appropriate increases, be reviewed annually by the Board or a committee thereof as part of the annual review of executive officers' remuneration. The decision on whether to grant an increase to the executive's base salary and the amount of any such increase shall be in the sole discretion of the Board or committee thereof.

NEOs are eligible to participate in such short-term incentive plans as may be implemented by the Company from time to time. The terms and conditions of all such incentive plans are subject to modification from time to time by the Board or committee thereof, in its sole discretion.

NEOs are eligible to participate in such long-term incentive plans as may be implemented by the Company from time to time. The terms and conditions of all such incentive plans are subject to modification from time to time by the Board or committee thereof, in its sole discretion.

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(1) The value of the long-term incentive components is determined using the Black-Scholes pricing model at the date of grant.

(2) Represents amounts earned in 2008 under the Company's annual non-equity incentive program in the form of annual cash bonus paid in 2009.

(3) Represents all compensation accrued relating to defined benefit and/or defined contribution pension plans.

(4) All other Compensation means the aggregate of amounts paid by Terasen Gas for the employee savings plan, payment in lieu of vacation and flexible benefit plan taxable cash.

NEOs participate in the Company's group insurance, benefit and retirement plans as may be in effect from time to time. The terms of all such group insurance benefit and retirement plans are subject to modification from time to time by the Board or committee thereof, in its sole discretion.

NEOs are entitled to vacation and to additional days off, all to be taken in accordance with the Company's policies and procedures, and as amended from time to time by the Company, in its sole discretion and the NEO agrees that such amendments shall not constitute a breach of the employment agreement.

During the NEO's employment, the Company reimburses the NEO for all traveling and other expenses actually, properly and necessarily incurred by the NEO in connection with the performance of the NEO's duties hereunder in accordance with the policies set from time to time by the Company, in its sole discretion. The NEO is required to furnish such receipts, vouchers or other evidence as are required by the Company to substantiate such expenses.

In addition, Mr. Jespersen's employment agreement provides for him to accrue one (1) additional year of credited service for each year between July 1, 1999 and June 30, 2009. In addition, Mr. Jespersen's employment agreement stipulates that his pension benefit on retirement will not be less than it would have been had he continued to accrue service under the M&E Plan and the M&E SRP after December 31, 2006.

C. INCENTIVE PLAN AWARDS

The following table sets forth the total number of options granted in Fortis Common Shares to the NEOs. The aggregate value is based on the difference between the Fortis Common Share price at December 31, 2008 of $24.59 and the exercise price of the options.

Option-based awards				
Name	**Number of securities underlying unexercised options (#)**	**Option exercise price ($)**	**Option expiration date**	**Value of unexercised in-the-money options ($) [(1)]**
R.L. (Randy) Jespersen	50,304	25.760	August 16, 2014	_
	46,696	28.270	February 26, 2015	_
	97,000			
S.A. Thomson	15,780	25.760	August 16, 2014	_
	14,592	28.270	February 26, 2015	_
	30,372			
D.L. Stout	14,556	25.760	August 16, 2014	_
	13,480	28.270	February 26, 2015	_
	28,036			
J.A. Marston	14,264	25.760	August 16, 2014	_
	13,212	28.270	February 26, 2015	_
	27,476			
R.M. Samels	12,288	25.760	August 16, 2014	_
	11,568	28.270	February 26, 2015	_
	23,856			

(1) No value was attributed to unexercised options that were out of the money on December 31, 2008.

The following table sets forth the value of option based awards and non-equity incentive compensation earned by the Named Executive Officers during the most recently completed financial year. The aggregate value of the option based awards vested during the year is based on the difference between the Fortis share price on the vesting date of any options that vested during 2008 and the exercise price of the options.

Name	Option-based awards – Value vested during the year ($) (1)	Non-equity incentive plan compensation – Value earned during the year ($)
R.L. (Randy) Jespersen	–	300,000
S.A. Thomson	–	175,000
D.L. Stout	–	145,000
J.A. Marston	–	138,000
R.M. Samels	–	115,000

D. PENSION PLAN BENEFITS

The following table sets forth the details of the defined benefit pension plan for the respective Named Executive Officers.

Name	Number of years credited service (#)(2)	Annual benefits payable ($)		Accrued obligation at start of year ($)	Compensatory Change ($)	Non-Compensatory Change ($)	Accrued obligation At year end ($)
		At year end 2008	At age 65				
R.L. (Randy) Jespersen	21.75	275,000	424,000	2,578,000	688,000	(296,000)	2,970,000
S.A. Thomson	0.42	2,000	2,000	22,000	-	(3,000)	19,000
D.L. Stout	0.42	2,000	2,000	38,000	-	(3,000)	35,000
J.A. Marston	0.42	2,000	2,000	31,000	-	(3,000)	28,000
R.M. Samels	15.50	66,000	66,000	984,000	140,000	(71,000)	1,053,000

The information shown in the defined benefit pension plan table above has been calculated using the valuation method and actuarial assumptions described in the pension note in the Company's annual financial statements for 2008.

The following table sets forth the details of the defined contribution pension plans for the respective Named Executive Officers.

Name	Accumulated value at start of year ($)	Compensatory ($)	Non-compensatory ($)	Accumulated value at year end ($)
S.A. Thomson	230,000	44,000	(45,000)	229,000
D.L. Stout	256,000	39,000	(50,000)	245,000
J.A. Marston	469,000	38,000	(114,000)	393,000
R.M. Samels	19,000	29,000	6,000	54,000

(1) No value was attributed to options that were out of the money on the vesting date.

(2) Mr. Jespersen has an employment agreement under which he accrues one additional year of credited service each year between July 1, 1999 and June 30, 2009. Pursuant to this agreement Mr. Jespersen has received an additional 9 years to his 12.75 years of service.

Prior to January 1, 2007, the executive officers of the Company were members of the Terasen Gas Inc. Retirement Plan for Management and Exempt Employees (the "M&E Plan"), a non-contributory pension plan. The M&E Plan has both a defined contribution (DC) provision and a defined benefit (DB) provision. The pension benefit under the DB provision for executive officers equals 2% of best 3-year average earnings for each year of credited service under the M&E Plan. Normal retirement is the first day of the month coincident with or next following attainment of age 65. Executive officers who are members of the M&E Plan are eligible to retire at age 55 or age 50 if age plus continuous service equals 65 years. If an executive officer is less than age 55, or age plus service is less than 80 years, the accrued pension to date of retirement is reduced 3% per year before age 60, otherwise no reduction applies.

On January 1, 2000, Terasen Gas implemented the defined contribution component of the M&E Plan and related Supplemental Retirement Plan (“SRP”). All executive officers were given a one-time option to remain in the defined benefit component or convert to the defined contribution component of the plans. The defined contribution component of the M&E Plan and SRP was frozen effective December 31, 2006.

Messrs. Jespersen and Samels participate in the DB provisions of the M&E Plan. The other executive officers participate in the DC provision of the M&E Plan.

The M&E Plan’s corresponding non-registered supplemental plan is the Terasen Gas Inc. Supplemental Retirement Plan (the “M&E SRP”). The M&E SRP is designed to provide the executive officers of the Company with the portion of the Company's pension promise that cannot be paid from the M&E Plan because of limits imposed by the Income Tax Act. As the executive officers are members of the M&E Plan, they are automatically members of the M&E SRP.

All members of the M&E Plan, including the executive officers, ceased to accrue further service under the M&E Plan and the M&E SRP effective December 31, 2006.

Effective January 1, 2007, all salaried employees of the Company, including the executive officers, joined the Pension Plan for Employees of Terasen Inc. (the "Terasen Plan"), a contributory defined benefit pension plan. The Terasen Plan provides a pension benefit equal to 2% of final average earnings (limited to $250,000 per year), integrated with the Canada Pension Plan (CPP). Members can retire with an unreduced pension at age 60 or when age plus continuous service equal 90 years. Pension benefits are otherwise reduced by 3% per year. Members are required to contribute 50% of the total required contributions to the Terasen Plan.

The Terasen Plan’s corresponding non-registered supplemental plan is the Supplemental Pension Plan for Employees of Terasen Inc. (the “Terasen SRP”). The Terasen SRP is designed to provide the executive officers of the Company with the portion of the Company's pension promise which cannot be paid from the Terasen Plan because of limits imposed by the Income Tax Act. As the executive officers are members of the Terasen Plan, they are automatically members of the Terasen SRP.

Effective May 31, 2007, all the executive officers, with the exception of Mr. Jespersen, ceased to accrue service under the Terasen Plan and the Terasen SRP. Mr. Jespersen continues to accrue service under the Terasen Plan at December 31, 2008.

In addition, Mr. Jespersen’s employment agreement stipulates that his pension benefit on retirement will not be less than it would have been had he continued to accrue service under the M&E Plan and the M&E SRP after December 31, 2006.

As at June 1, 2007, the executive officers of the Company, excluding Mr. Jespersen, joined the Terasen Inc. Group RRSP (the “Group RRSP”) and it’s corresponding supplemental plan, the Supplemental Executive Retirement Plan of Terasen Inc. (the “Executive SRP”) sponsored by the

Company. The Group RRSP directs a total contribution of 13% of earnings to an RRSP (6.5% each from employer and employee). The Executive SRP directs notional employer contributions equal to 13% of a member's earnings in excess of the Income Tax Act RRSP limit to a notional account.

Pensionable earnings under each of the M&E Plan, M&E SRP, Terasen Plan and Terasen SRP include base pay plus bonus paid under a predetermined incentive plan. Pensionable earnings under the Terasen Plan and Terasen SRP are limited to $250,000.

E. TERMINATION AND CHANGE OF CONTROL BENEFITS

The discussion below sets out the terms of the employment contracts that trigger benefits arising from termination and/or change of control as of December 31, 2008.

President and CEO Terasen Gas Inc. Employment Contract

Please note that Mr. Jespersen's contract terms are different than the NEOs' and as such are listed separately.

1. Termination by Mr. Jespersen

If in the event Mr. Jespersen terminates his employment with the Company any time after July 31, 2008 then Mr. Jespersen shall be entitled to be paid the following payments:

(a) an amount in lieu of any entitlement to annual incentive plan payment for the calendar year in which he terminates equivalent to the average amount of annual incentive plan payment paid or payable to Mr. Jespersen respecting the previous two (2) calendar years pro-rated from the beginning of the calendar year in which he terminates to the date of written notice of termination - **$300,000**;

(b) an amount equal to twelve (12) months' Annual Base Salary - **$440,000** and twelve (12) months' annual incentive plan payment under the terms of the annual incentive plan in place at the time of termination, which annual incentive plan payment will be based on the average annual incentive plan payment paid or payable for the previous two (2) calendar years - **$300,000**;

(c) an amount equivalent to all registered pension plan, supplemental pension plan contributions and all other benefit contributions and premiums ordinarily paid by the employer for insured benefits for Mr. Jespersen, which would, but for the termination, have been paid by the Company for the benefit of Mr. Jespersen during the twelve (12) months immediately following the date of termination at Mr. Jespersen's option rather than payment of an amount equivalent to pension contributions, the Company shall add an additional twelve (12) months to his age and an additional twelve (12) months to his service for the purpose of calculating the value of the Executive's pension benefit upon termination- **Pension $136,551 and Benefits - $40,819**; and

(d) an amount in respect of outplacement counselling equal to ten (10) percent of his Annual Base Salary - **$44,000**.

2. Termination Without Cause

In the event the Company terminates Mr. Jespersen without cause as of December 31, 2008 the Company would pay the amounts listed below in accordance with the employment agreement in lieu of notice of termination:

(a) an amount in lieu of any entitlement to short term incentive plan payment for the calendar year in which Mr. Jespersen is terminated equivalent to the average amount of short term incentive plan payment paid to Mr. Jespersen respecting the previous two (2) calendar years pro-rated from the beginning of the calendar year in which Mr. Jespersen is terminated to the date of written notice of termination - **$300,000**;

(b) an amount equivalent to twenty four (24) months Annual Base Salary - **$880,000** and twenty four (24) months short term incentive plan payment under the terms of the short term incentive plan in place at the time of termination, which short term incentive plan payment will be based on the average short term incentive plan payment paid or payable for the previous two (2) calendar years - **$600,000**;

(c) an amount equivalent to the sum of all registered pension plan, supplemental pension plan contributions and all other benefit contributions and premiums ordinarily paid by the Company for insured benefits for Mr. Jespersen, which would, but for the termination, have been paid by the Company for the benefit of the executive during the twenty four (24) months immediately following the date of termination of the employment agreement. At Mr. Jespersen's option, rather than payment of an amount equivalent to pension contributions, the Company shall add an additional twenty four (24) months to Mr. Jespersen's age and an additional twenty four (24) months to Mr. Jespersen's service for the purpose of calculating the value of Mr. Jespersen's pension benefit upon termination – **Pension – $273,102 and Benefits - $81,638**; and

(d) an amount in respect of outplacement counselling up to ten (10) percent of Mr. Jespersen's Annual Base Salary to be paid directly to an outplacement counselling agency as chosen by the Company - **$44,000**.

The executive's entitlement to any long-term incentive compensation at the date of termination shall be solely determined in accordance with the terms of any long-term incentive plan and any long-term incentive agreement in force as at the date of termination of the employment agreement.

3. Termination by Executive for Good Reason

In the event Mr. Jespersen terminates the employment agreement and resigns as an executive for "good reason", Mr. Jespersen shall be entitled to payments equal to the payments for termination without cause, set out above, provided that Mr. Jespersen must invoke his right to resign for good reason within ninety (90) days of the occurrence of any events which cause there to be good reason.

Good reason is defined as one or more of the following events, occurring without Mr. Jespersen's written consent:

(a) a material diminution or adverse change to the executive's position, nature of responsibilities, or authority within the Terasen Inc. companies that is not contemplated by the employment agreement

(b) a decrease in Mr. Jespersen's Annual Base Salary as provided in the Agreement (or as such amounts may be increased from time to time) excluding any amounts accrued by or paid to Mr. Jespersen relating to incentive compensation amounts and any decrease that may occur in the value of Mr. Jespersen's benefits under the Company's benefit plans resulting from a restructuring of any or all benefit plans at the discretion of the Company;

© any other failure by the Company to perform any material obligation under, or breach by the Company of any material provision of the agreement;

(d) a relocation of Mr. Jespersen's current primary work location to a location greater than eighty-three (83) kilometres from its current location; or

(e) any failure to secure the agreement of any successor entity to the Company to fully assume the Company's obligations under the employment agreement;

but does not include any financial transaction that may occur between Fortis Inc., Terasen Inc., the Company or, as applicable, any company related to Fortis Inc., Terasen

Inc. or the Company.

4. Change of Control

If the employment of Mr. Jespersen is terminated by the Company within three (3) months of a Change of Control, the Company will pay a severance payment, together with all legal and professional fees incurred by Mr. Jespersen, of:

(a) an amount in lieu of any entitlement to short term incentive plan payment for the calendar year in which Mr. Jespersen is terminated equivalent to the average amount of short term incentive plan payment paid to Mr. Jespersen respecting the previous two (2) calendar years pro-rated from the beginning of the calendar year in which Mr. Jespersen is terminated to the date of written notice of termination - **$300,000**; and,

(b) an amount equivalent to twenty four (24) months Annual Base Salary - $880,000 and twenty four (24) months short term incentive plan payment under the terms of the short term incentive plan in place at the time of termination, which short term incentive plan payment will be based on the average short term incentive plan payment paid or payable for the previous two (2) calendar years - **$600,000**;

(c) an amount equivalent to the sum of all registered pension plan, supplemental pension plan contributions and all other benefit contributions and premiums ordinarily paid by the Company for insured benefits for the executive, which would, but for the termination, have been paid by the Company for the benefit of Mr. Jespersen during the twenty four (24) months immediately following the date of termination of the employment agreement. At Mr. Jespersen's option, rather than payment of an amount equivalent to pension contributions, the Company shall add an additional twenty four (24) months to the executive's age and an additional twenty four (24) months to Mr. Jespersen's service for the purpose of calculating the value of the executive's pension benefit upon termination – **Pension – $273,102 and Benefits - $81,638**; and

(e) an amount in respect of outplacement counselling up to ten (10) percent of Mr. Jespersen's Annual Base Salary to be paid directly to an outplacement counselling agency as chosen by the Company - **$44,000.**

In addition, pursuant to the Fortis 2006 Stock Option Plan all options outstanding shall be immediately exercisable. As at December 31, 2008 had a Change of Control termination occurred, the obligation would have resulted in a payment of the unexercised Stock Options based on the difference between the strike price as the date of the grant and the market price as of December 31, 2008.

Executive Employment Contracts - NEOs

1. Termination Without Cause

In the event the Company terminates the executive without cause the Company will pay all amounts owed by the Company under the specific employment agreement as of the date of termination, the following payments in lieu of notice of termination:

(a) an amount in lieu of any entitlement to short term incentive plan payment for the calendar year in which the executive is terminated equivalent to the average amount of short term incentive plan payment paid to the executive respecting the previous two (2) calendar years pro-rated from the beginning of the calendar year in which the executive is terminated to the date of written notice of termination;

Executive	Amount
S.A. Thomson	$131,000
D.L. Stout	$127,000
J.A. Marston	$125,000
R.M. Samels	$ 86,500

(b) an amount in lieu of any entitlement to Annual Base Salary and short term incentive plan payments equivalent to two (2) times the executive's Annual Base Salary at the date of termination plus two (2) times the average amount of short term incentive plan payment paid or payable to the executive under the employment agreement respecting the previous two (2) full calendar years prior to the calendar year in which the executive is terminated;

Executive	Salary	Incentive
S.A. Thomson	$550,000	$262,000
D.L. Stout	$508,000	$255,000
J.A. Marston	$498,000	$250,000
R.M. Samels	$436,000	$173,000

(c) an amount in lieu of all registered pension plan, supplemental pension plan contributions and all other benefit contributions ordinarily paid by the Company for insured benefits equivalent to a percent of the total amount paid to the executive by the Company; and

Executive	Pension & Benefits	Percent (%)
S.A. Thomson	$243,600	30
D.L. Stout	$228,900	30
J.A. Marston	$224,400	30
R.M. Samels	$304,500	50

(d) an amount in respect of outplacement counselling up to ten (10) percent of the executive's Annual Base Salary to be paid directly to an outplacement counselling agency as chosen by the Company.

Executive	Amount
S.A. Thomson	$27,500
D.L. Stout	$25,400
J.A. Marston	$24,900
R.M. Samels	$21,800

The executive's entitlement to any long-term incentive compensation at the date of termination shall be solely determined in accordance with the terms of any long-term incentive plan and any long-term incentive agreement in force as at the date of termination of the employment Agreement.

2. Termination by Executive for Good Reason

In the event the executive terminates the employment agreement and resigns as an executive for "good reason", the executive shall be entitled to payments equal to the payments for termination without cause, set out above, provided that the executive must invoke his/her right to resign for good reason within ninety (90) days of the occurrence of any events which cause there to be good reason.

Good reason is defined as one or more of the following events, occurring without the executive's written consent:

(a) a material diminution or adverse change to the executive's position, nature of responsibilities, or authority within the Terasen Inc. companies that is not contemplated by the employment agreement

(b) a decrease in the executive's Annual Base Salary as provided in the Agreement (or as such amounts may be increased from time to time) excluding any amounts accrued by or paid to the executive relating to incentive compensation amounts and any decrease that may occur in the value of the executive's benefits under the Company's benefit plans resulting from a restructuring of any or all benefit plans at the discretion of the Company;

(c) any other failure by the Company to perform any material obligation under, or breach by the Company of any material provision of the agreement;

(d) a relocation of the executive's current primary work location to a location greater than eighty-three (83) kilometers from its current location; or

(e) any failure to secure the agreement of any successor entity to the Company to fully assume the Company's obligations under the employment agreement;

but does not include any financial transaction that may occur between Fortis Inc., Terasen Inc., the Company or, as applicable, any company related to Fortis Inc., Terasen Inc. or the Company.

F. DIRECTOR COMPENSATION

Directors of Terasen Gas also serve on the Board of Terasen Inc. Compensation which is paid directly by Terasen to each of Terasen directors, other than directors who are also officers or employees of Terasen or Terasen Gas, during the most recently completed financial year is as follows:

An annual retainer of $27,000 and Board meeting fees of $1250 and Committee meeting fees of $1000 for each meeting attended. In lieu of a director's retainer, the Chairman of the Board is paid an annual retainer of $67,500. The Chairs of the Audit and Risk Committee and the Governance and Human Resources Committee are paid additional retainers of $4,000 and $2,000 respectively. The directors are also reimbursed for direct expenses incurred in carrying out their duties as directors as well as $1000 for travel time for each group of meetings attended in person outside of the director's general district of residency. A portion of director compensation paid by Terasen, where appropriate, is recovered from Terasen Gas through an approved corporate services agreement.

Name	Fees earned ($)	All other compensation ($) [1]	Total ($)
Harold Calla	43,000	1,000	44,000
Ida J. Goodreau	40,000	1,000	41,000
R.L. (Randy) Jespersen			
Harry McWatters	43,250	5,000	48,250
H. Stanley Marshall	81,750	4,000	85,750
Barry Perry	42,250	4,000	46,250
Linda S. Petch	43,250	5,000	48,250
David R. Podmore	39,250	1,000	40,250
John C. Walker	42,250	4,000	46,250

[1] Represents travel fees time compensation paid to the Directors when attending out of town meetings.

Attachment 85.2

Terasen Inc.

May 5, 2005
Research Comment
Corporate Debt – Pipelines & Utilities

Q1/05 Results – Increased Leverage Is a Credit Concern

Sue McNamara, CFA
(416)-359-4584
sue.mcnamara@bmonb.com

Event

Terasen reported Q1/05 EPS of $0.63 (basic). After adjusting for the positive effect of a mark-to-market gain on Clean Energy's (45% - Terasen) price risk management activities recorded during the quarter, reported basic EPS were $0.60, moderately lower than our equity expectation of $0.64. For additional views, please refer to the equity research comment on Terasen Inc. by BMO Nesbitt Burns' equity analyst Karen Taylor.

Impact

Slightly negative.

Key Points

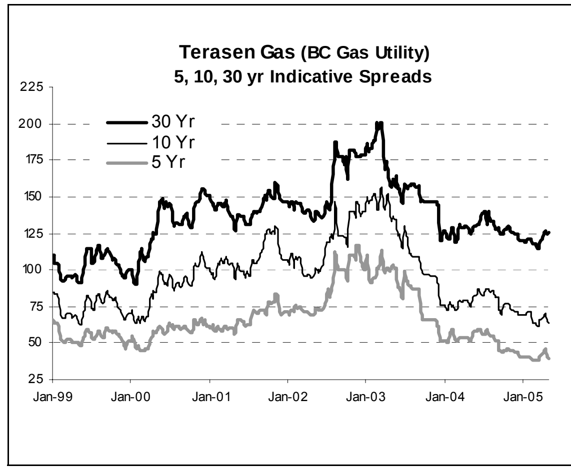
In Q1/05, Terasen Inc.'s total debt to capitalization ratio increased to 67.3% versus 64.4% at December 31, 2004 (including preferred securities as long-term debt). Our 2005 and 2006 debt to capitalization estimates are 64.74% and 64.72%, respectively, considerably higher than the averages for the pipeline and utility universe of 47.85% and 47.77%, respectively (Table 1).

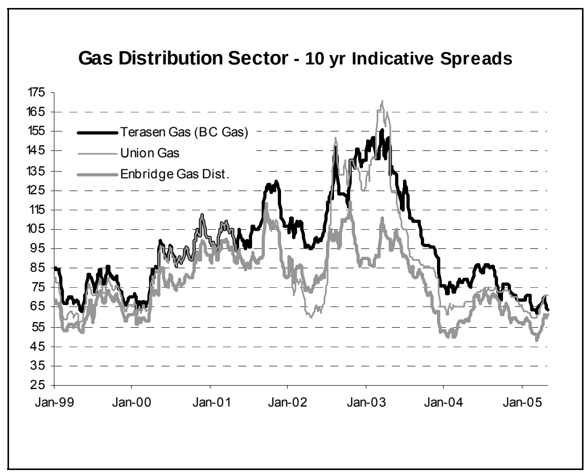
Recommendation

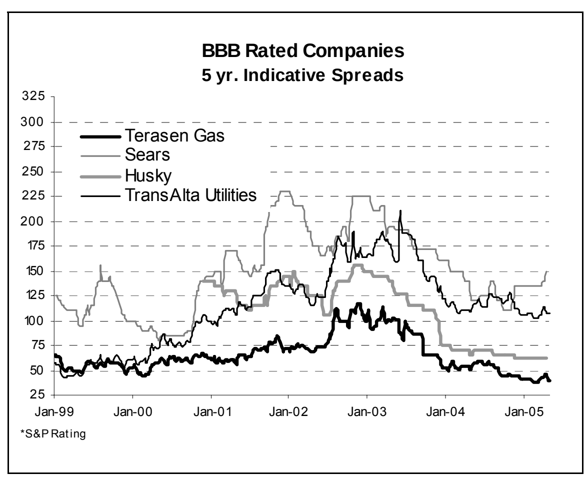
In 2005, Terasen Inc.'s 5-year and 10-year generic credit spreads tightened by 5 and 9 basis points, respectively, and the 30-year spreads have widened by 1 basis point. We believe that the company's spreads will likely widen over the next 12 months. We believe any significant spending by the company either through development projects or acquisitions (depending on how it is financed) could be a credit event, as the company is relatively thinly capitalized. We believe that a further credit risk is the expiry of the Trans Mountain system's negotiated toll settlement at the end of 2005. The company is currently in negotiations with shippers to extend or renew the toll agreement. The company's earnings and cash flow in 2006 could be negatively affected by the outcome of the negotiation.

Senior Unsecured Debt Ratings

DBRS	S&P	Moody's
A (Low)	BBB-	A3
Stable	Stable	Stable







Please refer to page 6 for Disclosure Statements, including the Analyst's Certification.

Table 1. Comparable Pipeline and Utility Capitalization Ratios

Company	2003A	2004A	2005E	2006E
Utilities - Subsidiaries				
CU Inc.	51.90%	52.32%	52.07%	51.82%
Enbridge Gas Distribution	61.28%	61.06%	55.53%	56.54%
Maritime Electric	66.26%	69.14%	79.36%	80.86%
Newfoundland Power	54.04%	53.42%	52.13%	46.52%
Nova Scotia Power	50.61%	51.32%	50.79%	49.17%
Terasen Gas	66.96%	63.60%	68.90%	69.53%
TransAlta Utilities	22.28%	72.29%	69.53%	67.06%
Union Gas	58.25%	58.34%	57.86%	57.31%
Group Average	**53.95%**	**60.19%**	**60.77%**	**59.85%**
Utilities - Holdcos/Corporates				
AltaGas	47.44%	45.55%	NA	NA
AltaLink LP	52.09%	52.30%	NA	NA
Canadian Utilities	47.66%	48.81%	46.58%	43.95%
Emera	51.93%	50.62%	51.36%	50.53%
Enersource Corporation	55.93%	56.09%	NA	NA
EPCOR Utilities	47.88%	42.26%	39.40%	37.92%
Fortis	59.03%	59.06%	57.17%	56.94%
GazMetro LP	59.86%	57.36%	54.76%	54.67%
Hydro One	48.38%	47.44%	47.39%	47.01%
Pacific Northern Gas	50.23%	49.22%	46.72%	44.42%
Toronto Hydro Corporation	56.78%	54.35%	NA	NA
TransAlta Corporation	44.85%	43.68%	43.47%	44.74%
Group Average	**51.84%**	**50.56%**	**48.36%**	**47.52%**
Pipelines - Subsidiaries				
Enbridge Pipelines	54.45%	45.89%	47.71%	45.31%
NOVA Gas Transmission	60.02%	61.96%	62.50%	63.28%
Terasen Pipelines	50.40%	43.22%	40.71%	51.84%
Group Average	**54.96%**	**50.36%**	**50.31%**	**53.48%**
Pipelines - Holdcos/Corporates				
Alliance Pipeline L.P.	68.29%	67.49%	67.58%	68.34%
Enbridge Inc.	56.23%	59.76%	57.60%	55.29%
TransCanada Corporation	58.11%	57.21%	56.11%	53.24%
Terasen Inc.	66.07%	65.16%	64.74%	64.72%
TQM Pipeline	69.75%	NA	NA	NA
Westcoast Energy	55.13%	53.25%	54.70%	54.29%
Group Average	**62.27%**	**60.57%**	**60.14%**	**59.17%**
Income Funds:				
Enbridge Income Fund	3.44%	6.71%	8.26%	7.49%
Inter Pipeline Income Fund	86.73%	28.30%	33.96%	31.80%
Pembina Pipeline Fund	16.90%	16.82%	16.73%	17.23%
Group Average	**35.69%**	**17.28%**	**19.65%**	**18.84%**

Source: BMO Nesbitt Burns' Equity Research Financial Models

Table 2. Cash Flow Statement (C$mm)

	Q1/04	Q1/05
Operating Activities:		
Net Earnings	82.2	66.3
Depreciation and Amortization	36.0	36.9
Equity Earnings	(3.9)	(3.3)
Future Income Taxes	2.3	(1.4)
Long-term Rate Stabilization Accounts	11.5	28.8
Other	2.9	0.6
	131.0	127.9
Change in Working Capital	37.2	(15.5)
Net Cash Provided by Operating Activities	**168.2**	**112.4**
Investing Activities		
Capital Expenditures	(28.9)	(83.8)
Acquisitions	-	-
Dispositions	7.6	-
Other	(6.1)	(1.6)
Cash Flow Provided by Investing Activities	**(27.4)**	**(85.4)**
Dividends:		
Capital Securities Distributions	(1.6)	-
Common Dividends	(20.3)	(23.7)
	(21.9)	**(23.7)**
Free Cash Flow	**118.9**	**3.3**
Financing Activities		
Short-term Debt	(121.4)	155.5
Long-term Debt	25.9	(40.6)
Terasen Gas Preference Shares	-	-
Capital Securities	-	-
Common Shares	7.7	4.1
Other	-	-
Change in Cash	(31.1)	(122.3)
Cash Flow Provided by Financing Activities	**(118.9)**	**(3.3)**
Cash (ST Debt), Beginning of Period	1.5	20.0
Change in Cash	31.1	122.3
Cash (ST Debt), End of Period	**32.6**	**142.3**

Source: Company Reports

Table 3. Capitalization

$mm	FY 2004	Q1/05
Bank Indebtedness	-	-
Short-term Debt	248.0	403.5
Long-term Debt	2,166.6	2,022.7
Current Maturities	416.7	516.8
Future Income Taxes/Deferred Credits	209.4	73.7
Capital Securities	125.0	125.0
Equity	1,422.1	1,418.5
Total Capitalization	**4,587.8**	**4,560.2**
%		
Bank Indebtedness	0.0%	0.0%
Short-term Debt	5.4%	8.8%
Long-term Debt	47.2%	44.4%
Current Maturities	9.1%	11.3%
Future Income Taxes	4.6%	1.6%
Capital Securities	2.7%	2.7%
Equity	31.0%	31.1%
Total Capitalization	**100.0%**	**100.0%**
Total Debt/Capitalization	**64.4%**	**67.3%**

Source: Company Reports

Terasen Inc.

Maturity Schedule

Company	Coupon	Maturity	Amount ($mm)	Instrument	Issue Date	Issue Spread	Callable	CUSIP	Outstanding ($mm)
Terasen Gas Inc.	9.800%	9-Feb-05	$40	MTNs	9-Feb-95	NA	Non-callable	05534ZAA4	$40
Terasen Gas Inc.	8.250%	29-Jun-05	$5	MTNs	29-Jun-95	NA	Non-callable	05534ZAB2	$5
Terasen Gas Inc.	6.500%	20-Jul-05	$200	MTNs	20-Jul-00	57.0 bps	Non-callable	05534ZAG1	$200
Terasen Gas Inc.	Floating[1]	26-Sep-05	$150	Floating Rate Notes	26-Sep-03	NA	Non-callable	88079ZAAZ	$150
Terasen Gas Inc.	4.850%	8-May-06	$100	MTNs	8-May-03	NA	Non-callable	88079ZAA1	$100
Terasen Gas Inc.	6.150%	31-Jul-06	$100	MTNs	30-Jul-01	73.0 bps	Make Whole + 18 bps	88079ZAL0	$100
Terasen Gas Inc.	9.750%	17-Dec-06	$20	Retractable Debentures	17-Dec-86	NA	Non-callable	NA	$20
Terasen Gas Inc.	6.500%	16-Oct-07	$100	MTNs	16-Oct-00	75.0 bps	Make Whole + 18 bps	05534ZAH9	$100
Terasen Gas Inc.	6.200%	2-Jun-08	$188	MTNs	21-Oct-97	80.0 bps	Non-callable	05534ZAC0	$188
Terasen Gas Inc.	6.300%	1-Dec-08	$200	MTNs	30-Nov-01	NA	Make Whole + 27 bps	11058ZAA8	$200
Terasen Gas Inc.	10.750%	8-Jun-09	$60	Debentures	8-Jun-89	NA	Make Whole + 40 bps	457452AH3	$60
Terasen Pipelines (Corridor)	4.240%	2-Feb-10	$150	Senior Unsecured	1-Feb-05	65.5 bps	Make Whole + 14 bps	88079VAA0	$150
Terasen Pipelines Inc.	11.500%	1-Jun-10	$35	Senior Unsecured	20-Jun-90	NA	Make Whole + 50 bps	NA	$35
Express Pipeline	6.470%	31-Dec-13	US$150	Senior Secured Notes	6-Feb-98	NA	Make Whole + 25 bps	30217VAA5	US$112.8
Terasen Inc.	5.560%	15-Sep-14	$125	MTNs	10-Sep-04	93.0 bps	Make Whole + 23 bps	88079ZAB9	$125
Terasen Pipelines (Corridor)	5.033%	2-Feb-15	$150	Senior Unsecured	1-Feb-05	81.1 bps	Make Whole + 19 bps	88079VAB8	$150
Terasen Gas Inc.	11.800%	30-Sep-15	$75	Mortgage	3-Dec-90	NA	Non-callable	05534RAA2	$75
Terasen Gas Inc.	10.300%	30-Sep-16	$200	Mortgage	21-Nov-91	104.0 bps	Make Whole + 35 bps	05534RAB0	$200
Express Pipeline	7.390%	31-Dec-19	US$250	Subordinated Secured Notes	6-Feb-98	NA	Make Whole + 50 bps	30217VAD9	US$239.2
Terasen Gas Inc.	6.950%	21-Sep-29	$150	MTNs	21-Sep-99	112.0 bps	Make Whole + 28 bps	05534ZAF3	$150
Terasen Gas Inc.	6.500%	1-May-34	$150	MTNs	29-Apr-04	127.0 bps	Make Whole + 31 bps	88078ZAB0	$150
Terasen Inc.	8.000%	19-Apr-40	$125	Subordinated Debentures	19-Apr-00	235.0 bps	Make Whole + 55 bps	05534KAA7	$125

[1] 35 basis points to 3 month Bankers Acceptances

Ownership Structure

Widely held.

Credit Facilities

Company	Facility Size	Amount Drawn Q2/04	Amount Drawn FY 2003	Letters of Credit Q2/04	Letters of Credit FY 2003	Maturity	Type
Terasen Inc.	$300	$200.0	$200.0			NA	Lines of Credit
Terasen Gas Inc.	$500	$70.0	$353.0			NA	Lines of Credit
Terasen Gas Vancouver	$213	$160.0	$160.0			NA	Lines of Credit
Corridor Pipelines	$525	$525.0	$525.0			NA	Lines of Credit

Shelf Prospectus

Company	Type	Amount	Remaining	Date	Expiry	Instruments
Terasen Gas Inc.	Shelf	$700	$550	10-Dec-03	10-Jan-05	MTNs
Terasen Inc.	Shelf	$800	$800	10-Dec-03	10-Jan-05	Unsecured Debentures

Pension Summary

	Pension Benefit Plans FY 2004 ($mm)	Pension Benefit Plans FY 2003 ($mm)	Other Benefit Plans FY 2004 ($mm)	Other Benefit Plans FY 2003 ($mm)
Accrued Benefit Obligation	298.0	276.7	67.3	61.0
Plan Assets	274.5	255.3	-	-
Funded Status	(23.5)	(21.4)	(67.3)	(61.0)
Accrued Benefit Asset (Liability) Net of Valuation Allowance	1.5	4.1	(32.3)	(24.6)
Discount Rate	6.00%	6.25%	6.00%	6.25%
Expected Long-term Rate of of Return on Assets	7.50%	7.50%	NA	NA
Rate of Future Increase in Compensation	3.50%	3.39%	NA	NA

Historical Ratings

DBRS Rating	DBRS Trend	DBRS Date	S&P Rating	S&P Trend	S&P Date	Moody's Rating	Moody's Trend	Moody's Date
A (L)	Stable	4-Apr-00	BBB	Stable	14-Nov-01	A3	Stable	8-Nov-01
			BBB	Credit Watch Negative	19-Nov-02	A3	Under Review - Negative	19-Nov-02
			BBB-	Stable	26-Jun-03	A3	Stable	12-Dec-02

Note: On March 12, 2004, Terasen Inc. disengaged its relationship with S&P. The rating agency will continue to provide ratings on Terasen and its subsidiaries using public information.

Company Risk Disclosure

In addition to the risks involved in investing in corporate debt securities generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Sue McNamara, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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Company Specific Disclosure

Disclosure 2: BMO Nesbitt Burns has undertaken an underwriting liability with respect to this issuer within the past 12 months.

Disclosure 3: BMO Nesbitt Burns has provided investment banking services with respect to this issuer within the past 12 months.

Disclosure 10: This issuer is a client (or was a client) of BMO Nesbitt Burns, HNC or an affiliate within the past 12 months: Investment Banking Services.

Dissemination of Research

BMO NBI Corporate Debt Research is available via our web site http://corporate.bmo.com/research/default.asp

Additional Matters

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Terasen Inc.

July 29, 2005
Research Comment
Corporate Debt – Pipelines & Utilities

Q2/05 Results – Leverage Concern Remains

Sue McNamara, CFA
(416)-359-4584
sue.mcnamara@bmonb.com

Event

Terasen reported Q2/05 EPS of $0.23 (after one-time adjustments), in line with our equity expectation.

Impact

Neutral.

Key Points

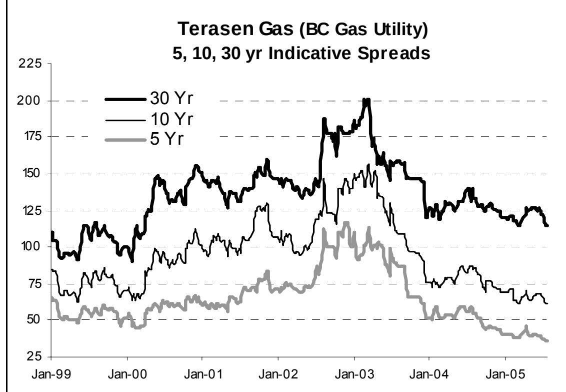
At June 30, 2005, the company's debt to total capital ratio was 64.6% versus 61.7% at year-end. If we assume that the company's available cash will be used to repay a portion of short-term debt, the company's ratio at quarter-end would decrease to 63.9%. We continue to believe that Terasen's leverage is higher than its peer group of comparable utilities. Although somewhat supported by the company's regulatory framework, we believe that the relatively high leverage could be a credit negative as the company pursues its robust list of development projects or undertakes a large scale acquisition.

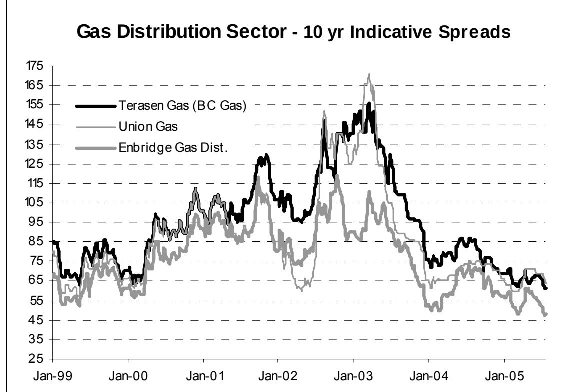
Recommendation

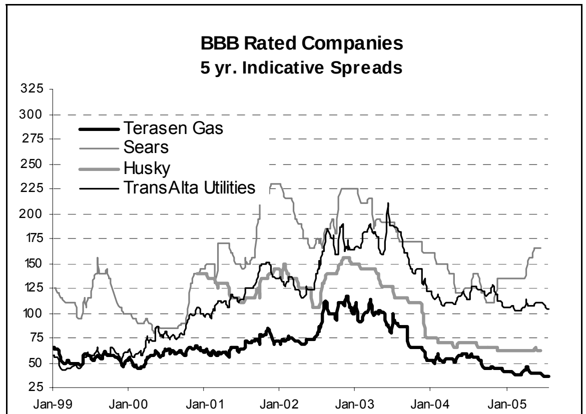
In 2005, Terasen Inc.'s 5-year, 10-year and 30-year generic credit spreads tightened by 8, 12 and 10 basis points, respectively. We believe that the company's spreads will likely widen over the next 12 months. We believe any significant spending by the company either through development projects or acquisitions (depending on how it is financed) could be a credit event, as the company is relatively thinly capitalized. We believe that a further credit risk is the expiry of the Trans Mountain system's negotiated toll settlement at the end of 2005. The company is currently in negotiations with shippers to extend or renew the toll agreement. The company's earnings and cash flow in 2006 could be negatively affected by the outcome of the negotiation. We also believe that regulatory risk at Terasen Gas is likely rising.

Senior Unsecured Debt Ratings

DBRS	S&P	Moody's
A (Low)	BBB-	A3
Stable	Stable	Stable







*S&P Rating

Q2/05 Results

Terasen reported Q2/05 EPS of $0.28. Q2/05 EPS were $0.23, directly in line with our equity expectation, after adjusting for: (i) a $3.9 million after-tax mark-to-market gain relating to Clean Energy's (40.4% - Terasen) price risk management activities; and (ii) approximately $1.15 million of tax benefits associated with the Express Pipeline attributable to Q1/05. For additional views, please refer to the equity research comment on Terasen Inc. by BMO Nesbitt Burns' equity analyst Karen Taylor.

Cash Flow

Terasen reported free cash of -$2.8 million during the quarter versus $25.4 million in Q2/04. The variance is largely attributable to an increase in capital expenditures ($43.1 million in Q2/05 versus $31.8 million in Q2/04) and a change in the working capital requirements contribution to operating cash flow ($9.8 million in Q2/05 versus $32.8 million in Q2/04). The free cash flow deficiency was funded with a draw on available cash.

Capital Resources

During the quarter, the company repaid $43 million and $6.4 million of short-term and long-term debt, respectively, from available cash. At quarter end, Terasen had $91.6 million of available cash remaining. Terasen Inc. has no debt maturities in 2005 and 2006, whereas Terasen Gas (100% - Terasen Inc.) has debt maturities of $350 million in 2005 and $220 million in 2006. We believe that the maturities will likely be refinanced or repaid with short-term debt issuance. At quarter-end, the company and its subsidiaries had $743 million available under its total lines of credit of $1.4 billion. At June 30, 2005, the company's debt to total capital ratio was 64.6% versus 61.7% at year-end. If we assume that the company's available cash will be used to repay a portion of short-term debt, the company's ratio at quarter-end would decrease to 63.9%. We continue to believe that Terasen's leverage is higher than its peer group of comparable utilities. Although somewhat supported by the company's regulatory framework, we believe that the relatively high leverage could be a credit negative as the company pursues its robust list of development projects or undertakes a large scale acquisition.

Table 1. Capitalization

	2004	Q2/05
$mm		
Bank Indebtedness	-	-
Short-term Debt	248.0	360.5
Long-term Debt	2,166.6	2,029.1
Current Maturities	416.7	628.9
Future Income Taxes/Deferred Credits	209.4	102.7
Capital Securities	125.0	125.0
Equity	1,422.1	1,427.5
Total Capitalization	**4,587.8**	**4,673.7**
Capitalization (%)		
Bank Indebtedness	0.0%	0.0%
Short-term Debt	5.4%	7.7%
Long-term Debt	47.2%	43.4%
Current Maturities	9.1%	13.5%
Future Income Taxes	4.6%	2.2%
Capital Securities	2.7%	2.7%
Equity	31.0%	30.5%
Total Capitalization	**100.0%**	**100.0%**
Debt/Total Capital	**61.7%**	**64.6%**

Source: Company Reports

Credit Ratings

Terasen Inc.'s senior unsecured debt is rated A(Low), BBB- and A3 by DBRS, S&P and Moody's, respectively. The outlook from all three rating agencies is Stable. S&P provides ratings coverage of the Terasen companies, based on publicly available information.

In its latest summary report on Terasen Inc., (June 3, 2005) S&P stated that the company's below average financial risk profile reflects the company's existing gas regulatory framework and is somewhat offset by the pipelines' negotiated shipper contracts. S&P expects that any acquisition or major development project will have risk profiles consistent with the regulated, energy infrastructure-type assets and will be financed in line with the company's current capital structure.

DBRS believes that the medium-term outlook for Terasen remains relatively stable given the increased asset diversification providing to earnings and operating cash flows. DBRS notes that the key risks to Terasen's credit ratings are related to the outcome of the large-scale projects currently under development. DBRS states that as the importance of Terasen's pipelines and non-regulated businesses continues to grow, the company will require a higher equity base to maintain its current ratings.

Moody's rates Terasen Inc. one notch below that senior unsecured rating of Terasen Gas, at A2. The one-notch differential reflects the structural subordination of Terasen's debt to operating subsidiary debt at Terasen Gas, Terasen Gas Vancouver Island, Corridor, Trans Mountain and Express as well as the lack of ring fencing or other restrictions that could limit Terasen Gas' ability to make dividend payments to Terasen Inc. Moody's expects that Terasen will take a prudent approach to the scale and financing of investments in the petroleum pipeline segment.

Recommendation

In 2005, Terasen Inc.’s 5-year, 10-year and 30-year generic credit spreads tightened by 8, 12 and 10 basis points, respectively. We note that Terasen Inc.’s credit spreads likely reflect a scarcity premium, as the holding company has only two maturities outstanding totalling $300 million. We believe that the company’s spreads will likely widen over the next 12 months. We believe any significant spending by the company either through development projects or acquisitions (depending on how it is financed) could be a credit event, as the company is relatively thinly capitalized. We believe that a further credit risk is the expiry of the Trans Mountain system’s negotiated toll settlement at the end of 2005. The company is currently in negotiations with shippers to extend or renew the toll agreement. The company’s earnings and cash flow in 2006 could be negatively affected by the outcome of the negotiation. We also believe that regulatory risk at Terasen Gas is likely rising. On July 11, the British Columbia Utilities Commission (BCUC) issued an Order and Notice of Procedural Conference regarding an application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. to determine the appropriate return on equity and capital structure, and to review and revise the automatic adjustment mechanism used by the BCUC to establish the allowed return on equity annually (please see Karen Taylor’s equity comment on Terasen Inc. dated July 15, 2005 for more details).

Table 3. Cash Flow Statement (C$mm)

	Q2/04	Q2/05
Operating Activities:		
Net Earnings	12.3	29.5
Depreciation and Amortization	37.8	36.3
Equity Earnings	(3.2)	(9.3)
Future Income Taxes	(0.2)	1.7
Long-term Rate Stabilization Accounts	2.2	(5.3)
Other	2.0	2.6
	50.9	55.5
Change in Working Capital	32.8	9.8
Net Cash Provided by Operating Activities	**83.7**	**65.3**
Investing Activities		
Capital Expenditures	(31.8)	(43.1)
Acquisitions	-	-
Dispositions	-	-
Other	(2.7)	(1.3)
Cash Flow Provided by Investing Activities	**(34.5)**	**(44.4)**
Dividends:		
Capital Securities Distributions	(1.7)	-
Common Dividends	(22.1)	(23.7)
	(23.8)	**(23.7)**
Free Cash Flow	**25.4**	**(2.8)**
Financing Activities		
Short-term Debt	(181.5)	(43.0)
Long-term Debt	139.6	(6.4)
Terasen Gas Preference Shares	-	-
Capital Securities	-	-
Common Shares	1.2	1.5
Other	-	-
Change in Cash	15.3	50.7
Cash Flow Provided by Financing Activities	**(25.4)**	**2.8**
Cash (ST Debt), Beginning of Period	32.6	142.3
Change in Cash	(15.3)	(50.7)
Cash (ST Debt), End of Period	**17.3**	**91.6**

Source: Company Reports

Terasen Inc.

Maturity Schedule

Company	Coupon	Maturity	Amount ($mm)	Instrument	Issue Date	Issue Spread	Callable	CUSIP	Outstanding ($mm)
Terasen Gas Inc.	9.800%	9-Feb-05	$40	MTNs	9-Feb-95	NA	Non-callable	05534ZAA4	$40
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Terasen Gas Inc.	6.500%	16-Oct-07	$100	MTNs	16-Oct-00	75.0 bps	Make Whole + 18 bps	05534ZAH9	$100
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Terasen Gas Inc.	6.300%	1-Dec-08	$200	MTNs	30-Nov-01	NA	Make Whole + 27 bps	11058ZAA8	$200
Terasen Gas Inc.	10.750%	8-Jun-09	$60	Debentures	8-Jun-89	NA	Make Whole + 40 bps	457452AH3	$60
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Terasen Pipelines Inc.	11.500%	1-Jun-10	$35	Senior Unsecured	20-Jun-90	NA	Make Whole + 50 bps	NA	$35
Express Pipeline	6.470%	31-Dec-13	US$150	Senior Secured Notes	6-Feb-98	NA	Make Whole + 25 bps	30217VAA5	US$112.8
Terasen Inc.	5.560%	15-Sep-14	$125	MTNs	10-Sep-04	93.0 bps	Make Whole + 23 bps	88079ZAB9	$125
Terasen Pipelines (Corridor)	5.033%	2-Feb-15	$150	Senior Unsecured	1-Feb-05	81.1 bps	Make Whole + 19 bps	88079VAB8	$150
Terasen Gas Inc.	11.800%	30-Sep-15	$75	Mortgage	3-Dec-90	NA	Non-callable	05534RAA2	$75
Terasen Gas Inc.	10.300%	30-Sep-16	$200	Mortgage	21-Nov-91	104.0 bps	Make Whole + 35 bps	05534RAB0	$200
Express Pipeline	7.390%	31-Dec-19	US$250	Subordinated Secured Notes	6-Feb-98	NA	Make Whole + 50 bps	30217VAD9	US$239.2
Terasen Gas Inc.	6.950%	21-Sep-29	$150	MTNs	21-Sep-99	112.0 bps	Make Whole + 28 bps	05534ZAF3	$150
Terasen Gas Inc.	6.500%	1-May-34	$150	MTNs	29-Apr-04	127.0 bps	Make Whole + 31 bps	88078ZAB0	$150
Terasen Inc.	8.000%	19-Apr-40	$125	Subordinated Debentures	19-Apr-00	235.0 bps	Make Whole + 55 bps	05534KAA7	$125

[1] 35 basis points to 3 month Bankers Acceptances

Ownership Structure

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Company	Facility Size	Amount Drawn Q2/04	Amount Drawn FY 2003	Letters of Credit Q2/04	Letters of Credit FY 2003	Maturity	Type
Terasen Inc.	$300	$200.0	$200.0			NA	Lines of Credit
Terasen Gas Inc.	$500	$70.0	$353.0			NA	Lines of Credit
Terasen Gas Vancouver	$213	$160.0	$160.0			NA	Lines of Credit
Corridor Pipelines	$525	$525.0	$525.0			NA	Lines of Credit

Shelf Prospectus

Company	Type	Amount	Remaining	Date	Expiry	Instruments
Terasen Gas Inc.	Shelf	$700	$550	10-Dec-03	10-Jan-05	MTNs
Terasen Inc.	Shelf	$800	$800	10-Dec-03	10-Jan-05	Unsecured Debentures

Pension Summary

	Pension Benefit Plans FY 2004 ($mm)	Pension Benefit Plans FY 2003 ($mm)	Other Benefit Plans FY 2004 ($mm)	Other Benefit Plans FY 2003 ($mm)
Accrued Benefit Obligation	298.0	276.7	67.3	61.0
Plan Assets	274.5	255.3	-	-
Funded Status	(23.5)	(21.4)	(67.3)	(61.0)
Accrued Benefit Asset (Liability) Net of Valuation Allowance	1.5	4.1	(32.3)	(24.6)
Discount Rate	6.00%	6.25%	6.00%	6.25%
Expected Long-term Rate of of Return on Assets	7.50%	7.50%	NA	NA
Rate of Future Increase in Compensation	3.50%	3.39%	NA	NA

Historical Ratings

DBRS Rating	DBRS Trend	DBRS Date	S&P Rating	S&P Trend	S&P Date	Moody's Rating	Moody's Trend	Moody's Date
A (L)	Stable	4-Apr-00	BBB	Stable	14-Nov-01	A3	Stable	8-Nov-01
			BBB	Credit Watch Negative	19-Nov-02	A3	Under Review - Negative	19-Nov-02
			BBB-	Stable	26-Jun-03	A3	Stable	12-Dec-02

Note: On March 12, 2004, Terasen Inc. disengaged its relationship with S&P. The rating agency will continue to provide ratings on Terasen and its subsidiaries using public information.

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In addition to the risks involved in investing in corporate debt securities generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Sue McNamara, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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Terasen Inc.

August 3, 2005
Research Comment
Corporate Debt – Pipelines & Utilities

Kinder Morgan Acquisition Appears Credit Negative for Bondholders

Sue McNamara, CFA
(416)-359-4584
sue.mcnamara@bmonb.com

Event

On August 1, 2005, Kinder Morgan Inc. announced a definitive agreement to acquire all of the outstanding shares of Terasen Inc.

Impact

Negative.

Key Points

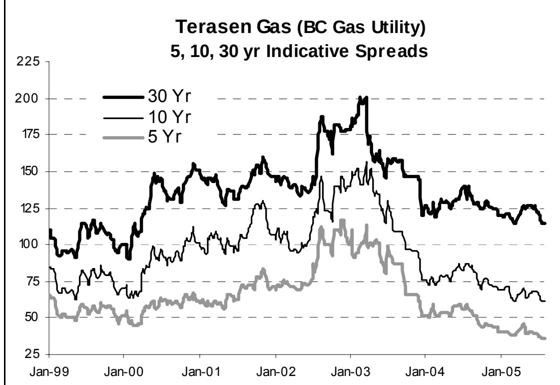
Kinder Morgan Inc. has stated that it intends to finance the acquisition with a combination of cash and equity up to a maximum proration of 65% cash and 35% equity. The company also stated on its conference call that it plans to fund the cash portion of the acquisition with debt financing provided by a Canadian subsidiary of Kinder Morgan Inc. After the closing of the transaction, Kinder Morgan expects that its debt to total capital ratio will likely increase to 56% versus 36.8% at June 30, 2005.

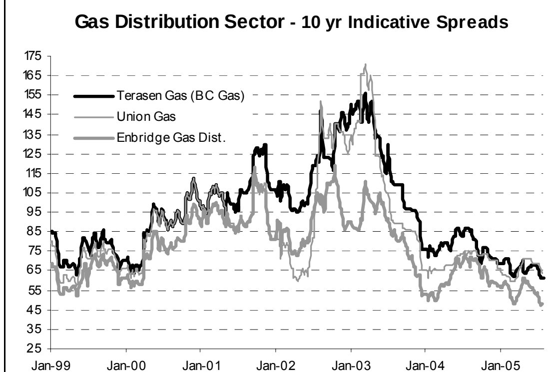
Recommendation

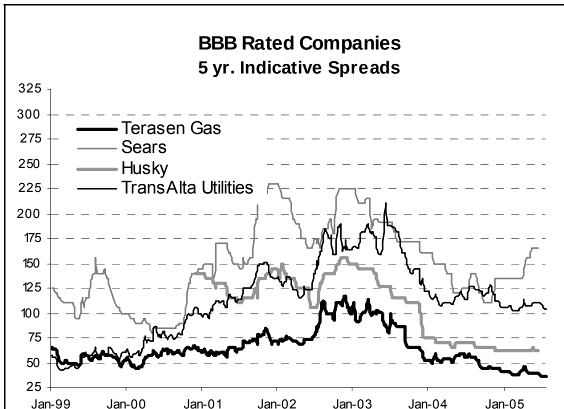
In 2005, Terasen Inc.'s 5-year, 10-year and 30-year generic credit spreads tightened by 8, 12 and 10 basis points, respectively. We note that Terasen Inc.'s credit spreads likely reflect a scarcity premium, as the holding company only has two maturities outstanding totalling $300 million. We believe that the acquisition is a credit negative and that the company's spreads will likely widen over the next 12 months. We believe that there is a risk that the credit ratings of the company could be negatively affected by the acquisition. As highlighted in detail within, Moody's, DBRS and S&P have placed Terasen Inc.'s credit Under Review with Negative Implications. S&P and DBRS have also placed KMI's credit ratings Under Review with Negative Implications. We note that the acquisition does address some of our previous credit concerns on Terasen Inc., namely the risk that any significant spending by Terasen Inc. either through development projects or acquisitions (depending on how it is financed) would be a credit event, as the company is relatively thinly capitalized.

Senior Unsecured Debt Ratings

DBRS	S&P	Moody's
A (Low)	BBB-	A3
UR - Negative	CW - Negative	UR - Negative







*S&P Rating

Acquisition

On August 1, 2005, Kinder Morgan Inc. announced a definitive agreement to acquire all of the outstanding shares of Terasen Inc. As part of the acquisition, Kinder Morgan will assume all of Terasen Inc's debt. The company had long- and short-term debt outstanding totalling $2.6 billion and $360.5 million, respectively, at June 30, 2005, of which $300 million was issued at the Terasen Inc. holding company level. Terasen Inc. has no debt maturities in the remainder of 2005, whereas Terasen Gas (100% - Terasen Inc.) has debt maturities of $350 million in 2005. We believe that the maturities will likely be refinanced or repaid with short-term debt issuance. The debt will likely mature prior to the expected close of the transaction (year-end 2005).

Kinder Morgan Inc. has stated that it intends to finance the acquisition with a combination of cash and equity up to a maximum proration of 65% cash and 35% equity. The company also stated on its conference call that it plans to fund the cash portion of the acquisition with debt financing provided by a Canadian subsidiary of Kinder Morgan Inc. After the closing of the transaction, Kinder Morgan expects that its debt to total capital ratio will likely increase to 56% versus 36.8% at June 30, 2005. For additional views on the acquisition, please refer to the equity research comment on Terasen Inc. by BMO Nesbitt Burns' equity analyst Karen Taylor, dated August 2, 2005.

Credit Ratings

Terasen Inc. Ratings

Terasen Inc.'s senior unsecured debt is rated A(Low), BBB- and A3 by DBRS, S&P and Moody's, respectively. The outlook is CreditWatch Negative by S&P and Under Review – Negative by DBRS and Moody's.

S&P has placed the credit ratings of Terasen Inc. and Terasen Gas on CreditWatch with Negative Implications. The outlook change reflects S&P's preliminary assessment that upon the closing of the transaction, the companies' credit quality will be assessed on a consolidated basis and will likely be equalized with the ratings on KMI, reflecting the same level of default risk. S&P states that the addition of significant amounts of debt will weaken KMI's balance sheet and debt protection measures. S&P must determine whether the effects of increased leverage eclipse the benefits of the addition of Terasen's asset base. Terasen's current credit quality reflects the average business profiles of the company's natural gas distribution business and liquids pipeline systems, offset by a weak financial profile. S&P further states that the company's below average deemed equity levels and allowed ROEs currently constrain the ratings on Terasen. We note that S&P provides ratings coverage of the Terasen companies, based on publicly available information.

DBRS has placed the ratings of Terasen Inc. Under Review with Negative Implications. DBRS states that the proposed transaction creates uncertainties with respect to the potential financing policies of Terasen, which could potentially have negative implications for its future financial profile. DBRS believes that ownership by a lower rated entity, KMI, could expose Terasen to increased dividend payments to support KMI's higher debt load. In its review, DBRS will also focus on the impact on the business and financial risk profile of the combined entity as well as tax, legal and regulatory issues of the cross-border transaction. We note that DBRS has maintained its Stable outlook on the A rated credit of Terasen Gas.

Moody's has placed the ratings of Terasen Inc. and Terasen Gas under review for possible downgrade. The change in outlook reflects the lower credit rating of KMI (Baa3) and its weak standalone financial profile relative to its peers. Moody's intends to assess what financial strategies KMI might employ for Terasen and what their implications might be for both Terasen and Terasen Gas. Moody's also states that Terasen Gas' ratings are being reviewed due to the lack of ringfencing or other restrictions that could limit its ability to make dividend payments to Terasen Inc. Moody's rates Terasen Inc. one notch below that senior unsecured rating of Terasen Gas at A2. The one-notch differential reflects the structural subordination of Terasen's debt to operating subsidiary debt at Terasen Gas, Terasen Gas Vancouver Island, Corridor, Trans Mountain and Express.

Kinder Morgan Inc. Ratings

DBRS rates Kinder Morgan Inc.'s senior unsecured debt BBB. The outlook is Under Review with Negative Implications. Based on its preliminary review, DBRS states that it expects the proposed transaction to have a positive effect on KMI's business risk as a result of the increased scope and scale of the company's regulated pipeline and gas distribution operations and growth potential. Conversely, DBRS states that the acquisition will likely increase KMI's balance sheet leverage to pre-2001 levels, which is relatively high and is expected to remain so for a few years.

S&P's credit rating on KMI is BBB. The outlook was changed to CreditWatch with Negative Implications from Stable following the announcement of the Terasen acquisition. The change in outlook reflects KMI's plan to increase financial leverage to fund the acquisition. S&P states that KMI's credit quality could be preserved if the potential improvement in KMI's business profile is capable of fully offsetting the higher financial risk. S&P stated in its latest summary on KMI (dated July 1, 2005) that the company's ratings are anchored by the company's regulated interstate natural gas pipeline and retail distribution assets, as well as the historically steady distributions that KMI receives from KMP.

Moody's rates the KMI's debt securities Baa2 with a Stable outlook. The company's credit rating and Stable outlook were affirmed following the acquisition announcement. Moody's believes that KMI will likely have sufficient free cash flow to cover the incremental interest expense and dividends from the acquisition financing. Moody's states that maintaining KMI's rating and outlook will entail achievement of the incremental earnings and cost savings that the company forecasts from Terasen as well as discipline in its dividend payouts. Moody's states that significant deviation from these expectations will cause the ratings agency to reassess KMI's ratings and outlook.

Recommendation

In 2005, Terasen Inc.'s 5-year, 10-year and 30-year generic credit spreads tightened by 8, 12 and 10 basis points, respectively. We note that Terasen Inc.'s credit spreads likely reflect a scarcity premium as the holding company has only two maturities outstanding, totalling $300 million. We believe that the acquisition is a credit negative and that the company's spreads will likely widen over the next 12 months. We believe that there is a risk that the credit ratings of the company could be negatively affected by the acquisition. As highlighted in detail above, Moody's, DBRS and S&P have placed Terasen Inc.'s credit Under Review with Negative Implications. S&P and DBRS have also placed KMI's credit ratings Under Review with Negative Implications. We note, however, that the acquisition does address some of our previous credit concerns on Terasen Inc., namely the risk that any significant spending by Terasen Inc., either through development projects or acquisitions (depending on how it is financed), would be a credit event, as the company is relatively thinly capitalized. We also believe that the following credit risks still remain:

1. The expiry of the Trans Mountain system's negotiated toll settlement at the end of 2005: the company is currently in negotiations with shippers to extend or renew the toll agreement. The company's earnings and cash flow in 2006 could be negatively affected by the outcome of the negotiation.
2. Regulatory risk at Terasen Gas: On July 11, the British Columbia Utilities Commission (BCUC) issued an Order and Notice of Procedural Conference regarding an application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. to determine the appropriate return on equity and capital structure and to review and revise the automatic adjustment mechanism used by the BCUC to establish the allowed return on equity, annually (please see Karen Taylor's equity comment on Terasen Inc. dated July 15, 2005 for more details).

Terasen Inc.

Maturity Schedule

Company	Coupon	Maturity	Amount ($mm)	Instrument	Issue Date	Issue Spread	Callable	CUSIP	Outstanding ($mm)
Terasen Gas Inc.	9.800%	9-Feb-05	$40	MTNs	9-Feb-95	NA	Non-callable	05534ZAA4	$40
Terasen Gas Inc.	8.250%	29-Jun-05	$5	MTNs	29-Jun-95	NA	Non-callable	05534ZAB2	$5
Terasen Gas Inc.	6.500%	20-Jul-05	$200	MTNs	20-Jul-00	57.0 bps	Non-callable	05534ZAG1	$200
Terasen Gas Inc.	Floating[1]	26-Sep-05	$150	Floating Rate Notes	26-Sep-03	NA	Non-callable	88079ZAAZ	$150
Terasen Gas Inc.	4.850%	8-May-06	$100	MTNs	8-May-03	NA	Non-callable	88079ZAA1	$100
Terasen Gas Inc.	6.150%	31-Jul-06	$100	MTNs	30-Jul-01	73.0 bps	Make Whole + 18 bps	88079ZAL0	$100
Terasen Gas Inc.	9.750%	17-Dec-06	$20	Retractable Debentures	17-Dec-86	NA	Non-callable	NA	$20
Terasen Gas Inc.	6.500%	16-Oct-07	$100	MTNs	16-Oct-00	75.0 bps	Make Whole + 18 bps	05534ZAH9	$100
Terasen Gas Inc.	6.200%	2-Jun-08	$188	MTNs	21-Oct-97	80.0 bps	Non-callable	05534ZAC0	$188
Terasen Gas Inc.	6.300%	1-Dec-08	$200	MTNs	30-Nov-01	NA	Make Whole + 27 bps	11058ZAA8	$200
Terasen Gas Inc.	10.750%	8-Jun-09	$60	Debentures	8-Jun-89	NA	Make Whole + 40 bps	457452AH3	$60
Terasen Pipelines (Corridor)	4.240%	2-Feb-10	$150	Senior Unsecured	1-Feb-05	65.5 bps	Make Whole + 14 bps	88079VAA0	$150
Terasen Pipelines Inc.	11.500%	1-Jun-10	$35	Senior Unsecured	20-Jun-90	NA	Make Whole + 50 bps	NA	$35
Express Pipeline	6.470%	31-Dec-13	US$150	Senior Secured Notes	6-Feb-98	NA	Make Whole + 25 bps	30217VAA5	US$112.8
Terasen Inc.	5.560%	15-Sep-14	$125	MTNs	10-Sep-04	93.0 bps	Make Whole + 23 bps	88079ZAB9	$125
Terasen Pipelines (Corridor)	5.033%	2-Feb-15	$150	Senior Unsecured	1-Feb-05	81.1 bps	Make Whole + 19 bps	88079VAB8	$150
Terasen Gas Inc.	11.800%	30-Sep-15	$75	Mortgage	3-Dec-90	NA	Non-callable	05534RAA2	$75
Terasen Gas Inc.	10.300%	30-Sep-16	$200	Mortgage	21-Nov-91	104.0 bps	Make Whole + 35 bps	05534RAB0	$200
Express Pipeline	7.390%	31-Dec-19	US$250	Subordinated Secured Notes	6-Feb-98	NA	Make Whole + 50 bps	30217VAD9	US$239.2
Terasen Gas Inc.	6.950%	21-Sep-29	$150	MTNs	21-Sep-99	112.0 bps	Make Whole + 28 bps	05534ZAF3	$150
Terasen Gas Inc.	6.500%	1-May-34	$150	MTNs	29-Apr-04	127.0 bps	Make Whole + 31 bps	88078ZAB0	$150
Terasen Inc.	8.000%	19-Apr-40	$125	Subordinated Debentures	19-Apr-00	235.0 bps	Make Whole + 55 bps	05534KAA7	$125

[1] 35 basis points to 3 month Bankers Acceptances

Ownership Structure

Widely held.

Credit Facilities

Company	Facility Size	Amount Drawn Q2/04	Amount Drawn FY 2003	Letters of Credit Q2/04	Letters of Credit FY 2003	Maturity	Type
Terasen Inc.	$300	$200.0	$200.0			NA	Lines of Credit
Terasen Gas Inc.	$500	$70.0	$353.0			NA	Lines of Credit
Terasen Gas Vancouver	$213	$160.0	$160.0			NA	Lines of Credit
Corridor Pipelines	$525	$525.0	$525.0			NA	Lines of Credit

Shelf Prospectus

Company	Type	Amount	Remaining	Date	Expiry	Instruments
Terasen Gas Inc.	Shelf	$700	$550	10-Dec-03	10-Jan-05	MTNs
Terasen Inc.	Shelf	$800	$800	10-Dec-03	10-Jan-05	Unsecured Debentures

Pension Summary

	Pension Benefit Plans FY 2004 ($mm)	Pension Benefit Plans FY 2003 ($mm)	Other Benefit Plans FY 2004 ($mm)	Other Benefit Plans FY 2003 ($mm)
Accrued Benefit Obligation	298.0	276.7	67.3	61.0
Plan Assets	274.5	255.3	-	-
Funded Status	(23.5)	(21.4)	(67.3)	(61.0)
Accrued Benefit Asset (Liability) Net of Valuation Allowance	1.5	4.1	(32.3)	(24.6)
Discount Rate	6.00%	6.25%	6.00%	6.25%
Expected Long-term Rate of of Return on Assets	7.50%	7.50%	NA	NA
Rate of Future Increase in Compensation	3.50%	3.39%	NA	NA

Historical Ratings

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CIBC World Markets

CORPORATE DEBT RESEARCH

www.cibcwm.com/research

Corporate Debt Comments

February 18, 2005

Joanna Zapior, CFA, CMC (416) 594-8498 Strategy, Utilities, Real Estate, CMBS

Trevor Bateman, CFA, CA (416) 594-7992 Banks, Non-bank financials, Autos, ABS

Kevin Yong, CFA (416) 956-6273 Oil & Gas, Aerospace

Phillip Armstrong (416) 956-3272 Telecom, Cable, Insurance, Retail, Consumer Products

Adam Bulley (416) 594-8626 Associate

Dina Giacomelli (416) 956-6056 Associate

Mark Litowitz (416) 956- 3858 Associate

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Terasen Inc: 4Q04 results.

Mark Litowitz, 416-956-3858 on behalf of Joanna Zapior.

CREDIT IMPACT: Neutral. Fourth quarter credit metrics were better, both year-over-year and sequentially, with leverage improving by roughly 2% and 1.6% from last quarter and a year ago, respectively. Solid operating cash flows and debt reduction were the primary drivers for the improvements in credit metrics. Strong growth in annual earnings from the pipelines business more than offset weaker annual earnings from the gas distribution segment. We continue to rate this company Market Perform.

Terasen: 4Q04	Debt to CF	EBITDA to Interest	Debt to Cap at book	Debt to Cap at Mkt	Realized ROE	LTM CF	YTD FCF	Adjusted debt
4Q04	10.0	3.0	68.3%	46.1%	11.7%	296	89	2,936
4Q03	10.5	2.7	69.9%	50.4%	11.0%	289	-229	3,030
3Q04	10.4	3.0	70.3%	50.6%	12.0%	304	-23	3,053

	4Q04	4Q03	YTD 04	YTD 03
Earnings contribution:				
GAS DISTRIBUTION				
Terasen Gas	36.2	37.5	69.7	72.6
Terasen Gas VC Island	6.4	7.3	26.2	26.2
PETROLEUM TRANSP.				
TransMountain	11.2	10.0	39.4	35.8
Corridor	3.8	4.0	15.6	10.7
Express	4.9	3.9	15.9	9.7
WATER & UTILITY	0.7	0.4	6.6	4.1
OTHER	(9.3)	(8.8)	(23.6)	(23.0)
Number of gas customers	NA	NA	875,166	859,183
Gas transportation volume (in petajoules)	19.6	20.2	72	72.2
Trans Mountain Canadian Mainline (bbl/d)	239,100	218,500	236,100	216,100
Trans Mountain US Mainline, included in Canadian Mainline (bbl/d)	89,300	57,700	91,700	54,600
Express System (bbl/d)	175,400	174,000	175,300	171,200

- Earnings from Terasen Gas were weaker in 2004 compared to 2003. Lower 2004 earnings were primarily due to lower allowed ROE, which offset efficiency gains from the integration of Vancouver Island and BC mainland operations. Gas customers grew by 1.86%, with about 16,000 new customers signed up during the year.
- Strong demand for oil in both Canada and south of the border helped to increase 2004 throughput volumes on TransMountain and Express pipelines compared to 2003. The increased year-over-year throughput was the main reason for stronger earnings contribution from Petroleum Transportation in 2004 compared with 2003 pipeline earnings. A full year of earnings contribution from Corridor, which commenced operation in May 2003, also contributed to year-over-year growth in pipeline earnings.
- Water and utility services segment earnings improved by $2.5 million in 2004. Most of this growth in earnings was due to organic growth from existing water and utility services business. Another source of earnings growth in this segment came from the acquisition of Fairbanks Sewer and Water.

	Analyst	Senior unsecured DBRS	Senior unsecured Moody's	Senior unsecured S&P	Credit fundamentals (1-3 years)	Rating change probab. (1 year)	Valuation	YTD total return: Shorter bond – Bond	Shorter bond – Return	Longer bond – Bond	Longer bond – Return	YTD change in spread: Shorter bond – Curr Sprd	Shorter bond – YTD Chng	Longer bond – Curr Sprd	Longer bond – YTD Chng
Pipelines: *Solid, largely regulated fundamentals, though regulatory environment disadvantages those companies that have North American growth plans as Cdn leverage is higher and returns lower. Our investment thesis rests on two pillars: 1) operating excellence and cost management will be key in light of 2) regulators pressuring for cost control, including returns. Holding company risk has been increasing with expansion in non-regulated areas, equity market push for growth, and still elevated leveragex*															
Gas distribution: *Stable sector, with strong operating franchises and good fundamentals. However, no standalone credits left (exceptand credit quality is affected by parent activities. See also our comment on the pipeline sector.*															
Enbridge Inc	**JZ**	A	A3	A-	May weaken (M&A, projects)	Medium	C	5.8% 2008	0.63%	8.2% 2024	2.58%	38	▲ 2	98	▼ 3
Enbridge Pipelines	**JZ**	A(high)	NR	A-	Stable	Medium	R	5.621% 2007	0.48%	7.2% 2032	3.52%	33	▲ 3	121	▼ 4
Enbridge Gas Dist.	**JZ**	A	NR	A-	Stable	Medium	R	11.15% 2009	0.81%	6.1% 2028	2.75%	53	▲ NA	101	⇔ 0
Alliance Pipe	**JZ**	A(low)	A3	BBB+	Strong	Very low	F	7.23% 2015	1.81%	7.217% 2025	2.04%	48	▼ 15	94	▼ 5
There is continued M&A and large project risk - lots of noise in the news as juggling for positions continues. The market now prices its uncertainty about committment to "A" ratings. Pipe acquisition in the GoM has eroded current balance sheet to the levels conti permissible under the S&P rating. Over time, we see balance sheet quality potentially weakening as more risky assets may be added while mature, stable assets end up in income trust. That it has historically been a defensive credit (low spread volatility) sible us a pause but history may not repeat itself. We view **opcos** as better credits in line with DBRS logic but not necessarily better value. Note **EGD** has a 2005 rate case. Regulatory stability has improved after a recent spate of decisions & PBR is possible. Mainline is renegotiating its settlement this fall. For **Alliance,** we like the "structuring premium" of an amortizer and the simplicity of this credit; not affected by how the ownership is structured; valuation reflects the defensive nature of this credit. It continues to perform as expected. Mgt turnover has been signficant (CFO earlier and now CEO) but this has no credit impact either for this contractually structured credit															
TransCanada	**JZ**	A	A2	A- Neg	Stable but event risk	Medium	R	6.05% 2007	0.60%	6.5% 2030	3.64%	31	▼ 5	110	▼ 5
Neg outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand (the most recent big one of a U.S. pipeline appears to have crystallized the agency thinking in a constructive way, subject to how conservative mgt will remainik will tak financing side) . Expansion in generation (including a now more likely restart of two more Bruce units), another potential large opportunistic acquisition & large projects in the longer term are credit risks. Regulatory environment continues to be unsate) . Expansi mgt's eyes which raises questions about whether the company will want to trustify some of the lower return regulated assets - a potential negative for bondholders.															
Duke (Westcoast)	**JZ**	A(low)	NR	BBB Pos	Improving	Low	R	5.7% 2008	0.66%	7.15% 2031	2.92%	48	▲ 2	123	⇔ 0
Duke (Union Gas)	**JZ**	A	NR	BBB Pos	Standalone stbl + DUK effect	Low	R	5.7% 2008	0.64%	8.65% 2025	2.51%	43	▲ 2	114	⇔ 0
MNEP	**JZ**	A	A1	A	Strong	Very low	F	NA	NA	6.9% 2019	1.45%	NA	NA	81	▲ 1
Duke took steps to turn the corner and the balance sheet repair actions have finally shown. Exit from non-core businesses continues & core regulated operations are stable. We think DENA will continue to be a source of grief for a while until markets improvtook until the new idea of contributing it to a joint venture hatches (lowering of risk). Resumed talk of opportunistic growth means that the golden age for bondholders is almost over (some upside remains from DENA cleanup & possible upgrade). We believe, in l th long run, **Union Gas's** distribution portion, as a non-core asset, is more separable from Duke than Westcoast. Its storage is a strategic asset to Duke. In the short term, Union provides solid cash flow to Duke and supports its credit quality. Spreads have performed reasonably well & are now in the middle of the utiltiy pack, leaving little further room for outperformance. For **MNEP**, we like structural protection and simplicity; valuation reflects the defensive nature of this credit.															
Terasen	**JZ**	A(low)	A3	BBB-	Stable but some event risk	Low	C	6.3% 2008	0.89%	NA	NA	55	▼ 3	NA	NA
Terasen Gas	**JZ**	A	A2	BBB	Stable	Low	C	NA	NA	6.95% 2029	2.87%	NA	NA	129	⇔ 0
Business fundamentals are a strong combination of a regulated gas distribution and pipelines, with aggressive financial profile determining the rating. Market pricing suggests that the market does not give full credence to the S&P rating (but still incorpoundamenta despite its now unsolicited status). Project CAPEX could be high. For **Terasen Gas**, we like the fundamentals of gas distribution at current spread, compared to historical spreads, but don't think that holdco spread can tighten much in the near term.															

Legal Disclaimers and Important Disclosure Footnotes

Important disclosures, including potential conflict of interest information, our system for rating investment opportunities and our dissemination policy can be obtained by visiting CIBC on the web at http://research.cibcwm.com/res/Policies/Policies.html or write to CIBC World Markets Inc. BCE Place, 161 Bay Street, 4th Floor, Toronto, Ontario M5J 2S8, Attention: Research Disclosures Request.

CIBC World Markets

CORPORATE DEBT RESEARCH

www.cibcwm.com/research

Corporate Debt Comments

May 5, 2005

Trevor Bateman, CFA, CA
(416) 594-7992
Banks, Non-bank financials, Autos, ABS

Phillip Armstrong
(416) 956-3272
Telecom, Cable, Insurance, Retail, Consumer Products

Kevin Yong, CFA
(416) 956-6273
Oil & Gas, Utilities, Aerospace

Joanna Zapior, CFA, CMC
(416) 594-8498
Strategy

See "Legal Disclaimer" section at the end of this report for important disclosures, including potential conflicts of interest.

Terasen: 1Q05 results weaker as expected but no impact on bonds

Kevin Yong (416) 956-6273 kevin.yong@cibc.ca
Joanna Zapior (416) 594-8498 joanna.zapior@cibc.ca

CREDIT IMPACT: Neutral. We maintain our Market Perform rating on Terasen Inc. and Terasen Gas bonds. As expected, Terasen reported weaker year-over-year earnings and cash flow. Since the main driver (lower pipeline throughput) for weaker cash flow was a temporary event, there should be no impact on bond spreads or credit ratings from 1Q05 results. Credit protection measures showed slight improvement on a year-over-year comparison despite the weaker cash flow. [Terasen Inc.: A(low)/Stable; A3/Stable] and [Terasen Gas: A/Stable; A2/Stable]

- Terasen's weaker cash flow was due to weaker earnings contribution from the Petroleum Transportation segment. Weaker earnings from this segment were a result of lower throughput at Trans Mountain and Express – both throughputs were negatively impacted by oil sands production outages and refinery maintenance. **Given that the lower throughputs were caused by temporary short-term production and refinery outages, the weaker cash flow reported in 1Q05 has no material impact on credit.**
- Although net borrowings increased in the quarter, the increase in leverage was offset by an increase in cash balance. As a result, net debt was essentially flat compared to net debt at the end of 2004 and increased by 1% compared to 1Q04 net debt level. This was the primary reason why credit metrics showed a slight improvement despite softer year-over-year cash flow generation.

CREDIT METRICS

Terasen: 1Q05	Debt to CF	Debt to Cap at book	EBITDA to Interest	FFO to Interest	LTM Realized ROE	LTM CF	LTM FCF
1Q05	10.6	67.3%	3.0	1.6	9.6%	276	-18
1Q04	10.0	67.9%	2.7	1.5	9.9%	289	28
4Q04	9.9	68.2%	3.0	1.7	11.7%	296	95

CONSOLIDATED QUARTERLY RESULTS SUMMARY

	Revenue	EBITDA	Net Interest Expense	Earnings	FFO	Free Cash Flow	Net borrowings (repayment) of debt	Share Issuance (repurchase)	Net Debt
year-over-year change	3%	-3%	0%	-2%	-6%	-96%	220%	-47%	1%
quarter-over-quarter change	8%	10%	-3%	19%	13%	-91%	159%	5%	0%
1Q05	$667	$172	$45	$66	$99	$5	$115	$4	$2,926
1Q04	$649	$177	$45	$68	$105	$117	-$96	$8	$2,904
4Q04	$616	$156	$47	$56	$87	$56	-$194	$4	$2,936

SELECTED OPERATING STATISTICS

	1Q05	1Q04	4Q04	YTD 03
Operating Statistics:				
Number of gas customers	878,560	862,631	875,166	875,166
Gas transportation volume (in petajoules)	21.6	21.9	19.6	72
Trans Mountain Canadian Mainline (bbl/d)	170,000	240,400	239,100	236,100
Trans Mountain US Mainline (bbl/d)	44,500	93,300	89,300	91,700
Express System (bbl/d)	166,900	171,300	175,400	175,300

- Despite lower reported earnings and cash flow from 1Q05, management is maintaining its full-year 2005 earnings guidance.
- The lower earnings contribution from the pipelines was partially offset by a small improvement in gas distribution earnings, earnings from water utilities, and lower corporate expenses.
- Terasen Gas earnings improved by $1 million in 1Q05 compared 1Q04. Operating efficiencies and customer growth more than offset lower allowed ROE in 2005.

Please refer to Our Opinions table (below) to place this credit in its sector-relative-value context

	Analyst	Senior unsecured DBRS	Senior unsecured Moody's	Senior unsecured S&P	Credit fundamentals (1-3 years)	Rating change probab. (1 year)	Valuation	YTD total return Shorter bond: Bond	Shorter bond: Return	Longer bond: Bond	Longer bond: Return	YTD change in spread Shorter bond: Curr Sprd	Shorter bond: YTD Chng	Longer bond: Curr Sprd	Longer bond: YTD Chng
Pipelines: *Solid, largely regulated fundamentals, though regulatory environment disadvantages those companies that have North American growth plans as Cdn leverage is higher and returns lower. Our investment thesis rests on two pillars: 1) operating excellence and cost management will be key in light of 2) regulators pressuring for cost control, including returns. Holding company risk has been increasing with expansion in non-regulated areas, equity market push for growth, and still elevated leveragex*															
Gas distribution: *Stable sector, with strong operating franchises and good fundamentals. However, no standalone credits left (exceptand credit quality is affected by parent activities. See also our comment on the pipeline sector.*															
Enbridge Inc	KY	A	A3	A-	May weaken (M&A, projects)	Medium	C	5.8% 2008	1.52%	8.2% 2024	3.93%	37	▲ 1	103	▲ 2
Enbridge Pipelines	KY	A(high)	NR	A-	Stable	Medium	R	5.621% 2007	1.07%	7.2% 2032	4.59%	37	▲ 7	130	▲ 5
Enbridge Gas Dist.	KY	A	NR	A-	Stable	Medium	R	11.15% 2009	1.74%	6.1% 2028	4.48%	57	▲ 6	104	▲ 3
Alliance Pipe	KY	A(low)	A3	BBB+	Strong	Very low	F	7.23% 2015	3.44%	7.217% 2025	3.42%	39	▼ 24	98	▼ 1
There are continued M&A and large project risks - lots of noise in the news as juggling for positions continues. The market now prices its uncertainty about committment to "A" ratings. Pipe acquisition in the GoM has eroded current balance sheet to the lev continue permissible under the S&P rating. Over time, we see balance sheet quality potentially weakening as more risky assets may be added while mature, stable assets end up in income trust. That it has historically been a defensive credit (low spread volatility) under the pause but history may not repeat itself. We view **opcos** as better credits in line with DBRS logic but not necessarily better value. Note **EGD** has a 2005 rate case. Regulatory stability has improved after a recent spate of decisions & PBR is possible. Mainline is renegotiating its settlement this fall. For **Alliance,** we like the "structuring premium" of an amortizer and the simplicity of this credit; not affected by how the ownership is structured; valuation reflects the defensive nature of this credit. It continues to perform as expected. Mgt turnover has been signficant (CFO earlier and now CEO) but this has no credit impact either for this contractually structured credit															
TransCanada	KY	A	A2	A- Neg	Stable but event risk	Medium	R	6.05% 2007	1.27%	6.5% 2030	3.90%	31	▼ 5	125	▲ 10
Neg outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand (the most recent big one of a U.S. pipeline appears to have crystallized the agency thinking in a constructive way, subject to how conservative mgt will remainik will tak financing side) . Expansion in generation and another potential large opportunistic acquisition & large projects in the longer term are credit risks. Regulatory environment continues to be unsatisfactory in mgt's eyes which raises questions about whetheing si company will want to trustify some of the lower return regulated assets - a potential negative for bondholders.															
Duke (Westcoast)	KY	A(low)	NR	BBB	Improving	Low	R	5.7% 2008	1.74%	7.15% 2031	3.02%	40	▼ 6	140	▲ 17
Duke (Union Gas)	KY	A	NR	BBB	Standalone stbl + DUK effect	Low	R	5.7% 2008	1.71%	8.65% 2025	3.19%	36	▼ 5	126	▲ 12
MNEP	KY	A	A1 UR-PD	A	Strong	Very low	F	NA	NA	6.9% 2019	2.86%	NA	NA	84	▲ 4
Duke took steps to turn the corner and the balance sheet repair actions have finally shown. Exit from non-core businesses continue & core regulated operations are stable. We think DENA will continue to be a source of grief for a while until markets improvesteps to t the new idea of contributing it to a joint venture hatches (lowering of risk). Resumed talk of opportunistic growth means that the golden age for bondholders is almost over (some upside remains from DENA cleanup & possible upgrade). We believe, in the loidea of **Union Gas's** distribution portion, as a non-core asset, is more separable from Duke than Westcoast. Its storage is a strategic asset to Duke. In the short term, Union provides solid cash flow to Duke and supports its credit quality. Spreads have performed reasonably well & are now in the middle of the utiltiy pack, leaving little further room for outperformance. For **MNEP**, we like structural protection and simplicity; valuation reflects the defensive nature of this credit.															
Terasen	KY	A(low)	A3	BBB-	Stable but some event risk	Low	C	6.3% 2008	1.92%	NA	NA	52	▼ 6	NA	NA
Terasen Gas	KY	A	A2	BBB	Stable	Low	C	NA	NA	6.95% 2029	5.57%	NA	NA	126	▼ 3
Business fundamentals are a strong combination of a regulated gas distribution and pipelines, with aggressive financial profile determining the rating. Market pricing suggests that the market does not give full credence to the S&P rating (but still incorpoundamental despite its now unsolicited status). Project CAPEX could be high. For **Terasen Gas**, we like the fundamentals of gas distribution at current spread, compared to historical spreads, but don't think that holdco spread can tighten much in the near term.															
Electric T&D: *Regulated; should have reasonably stable credit protection. Dark cloud of S&P and DBRS negative outlook on Ontario reflects political risk rather than material risk of deterioration in credit quality, and has by now almost dissipated though stability in the sector has not entirely returned. Our investment thesis is that given a general regulatory/rating agency/issuer stand-off, operating excellence and low cost structure will be key differentiating factors, given the aging assets and broad grid restructuot entirely retu North America.*															
Hydro One	KY	A Pos	A2	A	Stable	Low	R	7.15% 2010	2.21%	6.93% 2032	4.68%	34	▼ 1	85	▲ 4
Quasi-provincial credit nature still somewhat offset by political noise although the most recent policy changes appear to bypass Hydro One (with one exception being taking away from it the responsibility for long-term planning of the network); fairly valueovincial "provincially-supported" credit, otherwise expensive. Liberal government appears to be more constructive for the electricity sector than the Conservatives have been in terms of power market functionality, while the risk of divestiture remains very low.															
Toronto Hydro	KY	A	NR	A-	Stable	Low	R	6.11% 2013	2.42%	NA	NA	63	▲ 6	NA	NA
Some political and regulatory uncertainties remain. Scarcity value supports valuation. Recent political developments increase our confidence in a positive restructuring of the industry, including regulatory environment. Volatile non-regulated business ccal and reg impact earnings - mitigating factor is that TH said it will exit retail electricity by end 2006. We think that in the medium term performance-based regulation will introduce marginally higher operating risk.															

Our ratings:

Market Perform. The issuer's bonds are expected to perform in line with our universe of bonds over the next 12 months.
Outperfrom. The issuer's bonds are expected to outperform our universe of bonds over the next 12 months.
Underperform. The Issuer's bonds are expected to underperform our universe of bonds over the next 12 months.

Legal Disclaimers and Important Disclosure Footnotes

Important disclosures, including potential conflict of interest information, our system for rating investment opportunities and our dissemination policy can be obtained by visiting CIBC on the web at http://research.cibcwm.com/res/Policies/Policies.html or write to CIBC World Markets Inc. BCE Place, 161 Bay Street, 4th Floor, Toronto, Ontario M5J 2S8, Attention: Research Disclosures Request.

CIBC World Markets

Corporate Debt Research
Credit Comment

research.cibcwm.com/res/Crp/CrpResearch.html

Friday, July 29, 2005

Pipelines & Utilities

CIBCWM Bond Rating:

Market Perform

Credit Ratings: Terasen Inc.

S&P: BBB-/Stable

Moody's: A3/Stable

DBRS: A (low)/Stable

Credit Ratings: Terasen Gas

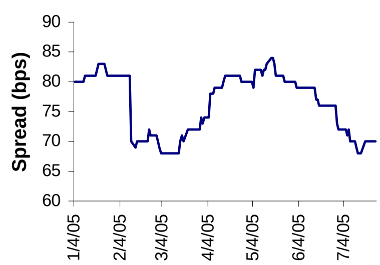
S&P: BBB/Stable

Moody's: A2/Stable

DBRS: A/Stable

Bond Spreads

TER 5.56% 9/15/2014



Source: CIBC World Markets

Kevin Yong

416-956-6273
kevin.yong@cibc.ca

Joanna Zapior

416-594-8498
joanna.zapior@cibc.ca

Terasen Inc.

Better 2Q05 financial results from all segments

CREDIT IMPACT: Neutral. Quarterly financial and operating results were neutral for credit and do not change our view on the credit of Terasen Inc. or Terasen Gas. Leverage ratios remain high, relative to peers such as Enbridge, but are stable to slightly improved on a year-over-year and quarter-over-quarter basis. As expected, year-over-year increases in quarterly earnings and cash flow were mostly attributed to improved earnings from the petroleum transportation segment, which was a result of increased throughput at Trans Mountain and Express expansion. Terasen Gas earnings also exhibited solid growth due to customer growth and lower operating expenses. We remain **Market Perform** on both Terasen Inc. and Terasen Gas.

Figure 1: Credit metrics are stable to slightly improved

Terasen Inc.	Net Debt to CF	Net Debt to Cap at book	EBITDA to Interest	FFO to Interest	LTM Realized ROE	LTM CF	LTM FCF
2Q05	9.9	67.2%	3.0	1.7	11.9%	297	-48
2Q04	10.0	67.9%	2.8	1.5	10.6%	287	78
1Q05	10.1	67.3%	2.9	1.6	11.1%	290	-18

Sources: Company reports, CIBC World Markets

- **Credit metrics slightly improved** – as shown in Figure 1, credit metrics are stable to slightly improved on a year-over-year and quarter-over-quarter comparison. Net debt to capitalization has been fairly stable over the last six quarters in and around the 68% level for five of the last six quarters; exception was 4Q04 when this ratio ticked up to 69.6%. Coverage ratios remain solid on a year-over-year and quarter-over-quarter comparison.
- **Cash flow improved but free cash flow was negative** – growth in cash flow before working capital (FFO) was mostly a result of higher quarterly earnings. Free cash flow was slightly negative due to lower cash from working capital and higher CAPEX.
- **Trans Mountain's new incentive tolling settlement (ITS)** – management said on the conference call that discussions with the shippers were going well and that it expects a new agreement by the end of 2005. Strong support from shippers for the first phase of TMX 1 is positive for ITS negotiation.
- **Corridor expansion** – this is estimated to cost about $800 million. The proposed expansion is two-fold. The first would be increasing pumping capacity on the existing line, with a second phase involving the construction of a new 42-inch pipeline. Current capacity of 258 mbbl/d should increase to 278 mbbl/d by April 2006. Addition of new pipeline is expected to increase capacity to about 480 mbbl/d by 2009. Terasen expects to have some third-party shippers on the expanded capacity.

Trevor Bateman, CFA, CA (416) 594-7992 Banks, Non-bank financials, Autos, ABS

Phillip Armstrong (416) 956-3272 Telecom, Cable, Insurance, Retail, Consumer Products

Kevin Yong, CFA (416) 956-6273 Oil & Gas, Utilities, Aerospace

Joanna Zapior, CFA, CMC (416) 594-8498 Strategy

Dina Giacomelli –Editor (416) 956-6056

CIBC World Markets Inc. PO Box 500, 161 Bay Street, BCE Place, Toronto, Canada M5J 2S8 Bloomberg@wgec1 **(416) 594-7000**
CIBC World Markets Corp. 300 Madison Avenue, New York, NY 10017 **(212) 856-4000, (800) 999-6726**

Figure 2: Earnings and FFO growing year-over-year

	Revenue	EBITDA	Net Interest Expense	Earnings	FFO	Free Cash Flow	Net borrowings (repayment) of debt	Share Issuance (repurchase)	Net Debt
year-over-year change	13%	9%	3%	65%	12%	-105%	-18%	25%	2%
quarter-over-quarter change	-38%	-37%	-3%	-56%	-39%	-131%	-143%	-63%	0%
2Q05	$412	$109	$44	$30	$61	-$1	-$49	$2	$2,927
2Q04	$365	$100	$43	$18	$54	$28	-$42	$1	$2,877
1Q05	$667	$172	$45	$66	$99	$5	$115	$4	$2,926

Sources: Company reports, CIBC World Markets

- **Year-over-year increase in earnings came from all segments.** Natural gas earnings improved by $2.6 million in 2Q05 compared to 2Q04. Petroleum transportation earnings improved by $4.7 million in 2Q05 relative to 2Q04. Water and utility services earnings grew by $1.2 million year-over-year in the quarter.

- **Terasen Gas grows steadily** – improvement in earnings was due to strong customer growth, which is a result of a healthy economic environment in B.C., and better operating efficiencies. Both of these positives more than offset the lower allowed ROE in 2005 versus 2004; therefore, 2Q05 earnings increased by $2.6 million over 2Q04 earnings. Improved efficiencies resulted in a year-over-year decline in quarterly operating and maintenance expense of $1.8 million in 2Q05.

- **Petroleum transportation earnings strengthened due to a rebound in volume on Trans Mountain and higher than expected earnings from Express expansion** – Trans Mountain earnings improved by $0.8 million in 2Q05 over 2Q04 earnings. The big lift in earnings came from the Express expansion, which surprised to the upside with earnings of $7.6 million in 2Q05 compared to $3.2 million in 2Q04. Realization of additional tax benefits helped to boost the earnings in the quarter.

- **Water and utility services continue to grow slowly and steadily** – 2Q05 earnings from this segment improved to $3.8 million in 2Q05 compared to $2.6 million in 2Q04. Improved earnings were a result of growth in the Waterworks business from Alberta and B.C. and contribution from Fairbanks Sewer and Water. Management indicated on the conference call that it will continue to grow this business through small projects that provide good steady growth opportunities.

Figure 3: Growing liquids pipeline throughput and natural gas customers

Operating Statistics:	2Q05	2Q04	1Q05	2004
Number of gas customers	879,647	862,752	878,560	875,166
Gas transportation volume (in petajoules)	15.8	16	21.6	72
Trans Mountain Canadian Mainline (bbl/d)	242,100	223,500	170,000	236,100
Trans Mountain US Mainline (bbl/d)	74,600	97,400	44,500	91,700
Express System (bbl/d)	226,500	176,200	166,900	175,300

Sources: Company reports

Please refer to Our Opinions table (below) to place this credit in its sector-relative-value context

26-Jul-05	Analyst	Senior unsecured DBRS	Moody's	S&P	Credit fundamentals (1-3 years)	Rating change probab. (1 year)	Valuation	YTD total return: Shorter bond — Bond	Return	Longer bond — Bond	Return	YTD change in spread: Shorter bond — Curr Sprd	YTD Chng	Longer bond — Curr Sprd	YTD Chng

Pipelines: *Solid, largely regulated fundamentals, though regulatory environment disadvantages those companies that have North American growth plans as Cdn leverage is higher and returns lower. Our investment thesis rests on two pillars: 1) operating excellence and cost management will be key in light of 2) regulators pressuring for cost control, including returns. Holding company risk has been increasing with expansion in non-regulated areas, equity market push for growth, and still elevated leverage.*

Gas distribution: *Stable sector, with strong operating franchises and good fundamentals. However, no standalone credits left (exceptand credit quality is affected by parent activities. See also our comment on the pipeline sector.*

Enbridge Inc	KY	A	A3	A-	May weaken (M&A, projects)	Medium	C	5.8% 2008	2.59%	8.2% 2024	8.73%	32	▼ 4	90	▼ 11
Enbridge Pipelines	KY	A(high)	NR	A-	Stable	Medium	R	5.621% 2007	1.86%	7.2% 2032	10.70%	29	▼ 1	116	▼ 9
Enbridge Gas Dist.	KY	A	NR	A-	Stable	Medium	R	11.15% 2009	2.96%	6.1% 2028	9.77%	55	▲ 4	95	▼ 6
Alliance Pipe	KY	A(low)	A3	BBB+	Strong	Very low	F	7.23% 2015	4.76%	7.217% 2025	5.82%	36	▼ 27	91	▼ 8

There are continued M&A and large project risks - lots of noise in the news as jockeying for positions continues. The market now prices its uncertainty about committment to "A" ratings. Pipe acquisition in the GoM has eroded current balance sheet to the lecontinued permissible under the S&P rating. Over time, we see balance sheet quality potentially weakening as more risky assets may be added while mature, stable assets end up in income trust. That it has historically been a defensive credit (low spread volatility) under the pause but history may not repeat itself. We view opcos as better credits in line with DBRS logic but not necessarily better value. Note EGD has a 2006 rate case. Regulatory stability has improved after a recent spate of decisions & PBR is possible. Mainline negotiated ITS is complete and is neutral to slightly positive from a credit perspective. For Alliance, we like the "structuring premium" of an amortizer and the simplicity of this credit; not affected by how the ownership is structured; valuation reflects the defensive nature of this credit. It continues to perform as expected. Mgt turnover has been signficant (CFO earlier and now CEO) but this has no credit impact either for this contractually structured credit

TransCanada	KY	A	A2	A- Neg	Stable but event risk	Medium	F	6.05% 2007	1.94%	6.5% 2030	9.36%	30	▼ 6	115	↔ 0

Negative outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand. We think that short-term acquisition risk is reduced with the announced sale of TransCanada Power LP interests to EPCOR, which should improve TRP's cash outlook w and balance sheet capacity when the transaction closes. Management's commitment to maintain TRP's "A" rating also mitigates short-term risks associated with acquisitions. We read this to mean that TRP will likely make acquisitions in a conservative way (ce sheet not be a detriment to bondholders). The improved balance sheet and renewed commitment to its "A" rating gives us more comfort that TRP's credit quality may not deteriorate if it were to make a large acquisition in the near-term.

Duke (Westcoast)	KY	A(low) UR-Dev	NR	BBB CW-Neg	Improving	Low	R	5.7% 2008	2.74%	7.15% 2031	8.29%	38	▼ 8	131	▲ 8
Duke (Union Gas)	KY	A UR-Dev	NR	BBB CW-Neg	Standalone stbl + DUK effect	Low	R	5.7% 2008	2.67%	8.65% 2025	7.85%	36	▼ 5	118	▲ 4
MNEP	KY	A	A1 UR-PD	A	Strong	Very low	F	NA	NA	6.9% 2019	6.57%	NA	NA	63	▼ 17

The announced merger with Cinergy should take some of the growth pressures off management, which is good for bondholders. Also good for bondholders in that this is an all stock deal and Cinergy's merchant assets (which is mostly coal) should diversify thenounce risks. Although S&P agrees with us that the transaction in itself is not a detriment to credit, it nevertheless put Duke on credit watch negative because of the uncertainty with regards to what Duke mgmt may do post merger - namely possibility of separatiS&P agrees with and unregulated utilities. We believe the separation of the regulated and unregulated businesses may actually be good for credit ratings of Westcoast and Union Gas. However, in the event that nothing happens post merger and Duke remains whole, as it is nunre ratings of Westcoast and Union Gas should remain unchanged. Of greater concern should be the talk of spinning out the Westcoast assets into an income trust, which we believe could be a mild negative (depending on how the trust is structured) for Westcoasta bondholders. Union Gas for now is not expected to be put into an income trust. For MNEP, we like structural protection and simplicity; valuation reflects the defensive nature of this credit.

Terasen	KY	A(low)	A3	BBB-	Stable but some event risk	Low	F	6.3% 2008	3.13%	NA	NA	46	▼ 12	NA	NA
Terasen Gas	KY	A	A2	BBB	Stable	Low	F	NA	NA	6.95% 2029	10.74%	NA	NA	118	▼ 11

Business fundamentals are a strong combination of a regulated gas distribution and pipelines, with aggressive financial profile. Although to be fair, we note that most of TER's consolidated debt resides at INL, which is a regulated utility that is restricts are a strong combi equity it can have in its capital structure by the BCUC. BCUC's allowed equity cushion for gas utilities is among the lowest in Canada. We also like the relatively conservative near-term growth of TER, with most of the growth focused on adding to regulatn have in it With ENB getting a new ITS, attention now is on Trans Mountain's ITS. We think that Trans Mountain's ROE will fall but not back to the allowed ROE. Producers will likely give Trans Mountain chances to make up most of the rebased earnings with incentives.B getti new ITS will have greater impact on TER's consolidated cash flow and credit metrics because all of Trans Mountain is under the current ITS.

Integrated electric: *A mixed bag of companies, ranging from trasnmission dominated, through fully integrated but in a regulated setting, to a mix of regulated T&D and non-regualated generation, and even E&P. Hence risk profiles vary and the companies in this group are not direct comparables.*

Emera	KY	BBB(high)	Baa2	BBB+ Neg	May weaken	Medium	R	NA	NA	NA	NA	NA	NA	NA	NA
Nova Scotia Power	KY	A(low)	Baa1	BBB+ Neg	May weaken	Medium	R	5.55% 2009	3.46%	8.85% 2025	8.78%	43	▼ 5	130	▲ 1

The negative regulatory decision for NSP that disallowed fuel adjustment clause and granted lower allowed ROE than anticipated is a negative for credit and may lead to increase rating risk. The potential negative cash flow impact of this decision means th regulatory increased risk that Emera will not be able to hit the credit metric targets that S&P has set for the company. Furthermore, the negative decision underscores the fact that NSP's relationship with its regulator has taken a step backwards rather than our expthat Emera will this relationship would improve. NSP recently filed 2006 rate case seeking 15% increase in rates in order to recover significant increase in fuel expense. We don't think that they will get the full amount, which puts NSP's cash flow and credit metrics atuld improve. NSP issuer here is really NSP, but even it has scarcity value.

EPCOR	KY	A(low)	NR	BBB+	Stable	Low	R	6.2% 2008	2.96%	6.8% 2029	11.11%	37	▼ 10	118	▼ 9

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or write to CIBC World Markets Inc. BCE Place, 161 Bay Street, 4th Floor, Toronto, Ontario M5J 2S8, Attention: Research Disclosures Request.

Our Ratings

Market Perform	The issuer's bonds are expected to perform in line with our universe of bonds over the next 12 months
Outperform	The issuer's bonds are expected to outperform our universe of bonds over the next 12 months.
Underperform	The issuer's bonds are expected to underperform our universe of bonds over the next 12 months

Rating Category	CIBC WM - CDR Universe (equally weighted)
Outperform	38%
Market Perform	46%
Underperform	15%

CIBC World Markets

Corporate Debt Research
Credit Comment

research.cibcwm.com/res/Crp/CrpResearch.html

Tuesday, August 02, 2005

Pipelines & Utilities

CIBCWM Bond Rating:

Market Perform

Credit Ratings: Terasen Inc.

S&P: BBB-/Stable

Moody's: A3/Stable

DBRS: A (low)/Stable

Credit Ratings: Terasen Gas

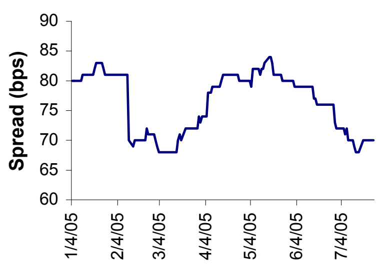
S&P: BBB/Stable

Moody's: A2/Stable

DBRS: A/Stable

Bond Spreads

TER 5.56% 9/15/2014



Source: CIBC World Markets

Kevin Yong

416-956-6273
kevin.yong@cibc.ca

Joanna Zapior

416-594-8498
joanna.zapior@cibc.ca

Terasen Inc.

Kinder Morgan to acquire Terasen Inc.

CREDIT IMPACT: Neutral. **From a credit perspective we continue to think that this transaction should be neutral for Terasen bondholders** since most of the Terasen operating company (opco) bonds will likely remain at the opcos and the opcos will likely retain the current operating autonomy that they now enjoy. So in effect other than a change of parent ownership, there should be no fundamental changes to the bonds of Terasen opcos. **There may be some rating volatility due to the transaction and given the difference between Terasen opco ratings and Kinder Morgan Inc. (BBB rated with one positive outlook) ratings. We think that it is reasonable to assume that Terasen Inc. and Terasen opco ratings in the "A" category may be at risk.** As we go to print, Moody's placed Terasen Inc and Terasen Gas senior unsecured ratings under review for possible downgrade. If Terasen Inc and Terasen Gas ratings were to get downgraded (Moody's and DBRS), then we should expect to see some softness in spreads. At this point though, **given the scarcity value of Terasen bonds, strong demand for utility bonds, and the fact that nothing fundamentally has changed, we will maintain our Market Perform rating on Terasen Inc. and Terasen Gas bonds.** Terasen Inc. and Terasen Gas bond spreads have been resilient today with spreads unchanged to a touch wider this morning.

Conference call highlights:

- **All current opco level debt will remain at the opco level** – this means that all bonds of Terasen Gas, Terasen Gas Vancouver Island, Terasen Pipelines (Trans Mountain), and Terasen Pipelines (Corridor) will remain at the opco level. See previous comment for Terasen corporate structure and capital structure.
- **Opcos will retain current operating autonomy according to Kinder Morgan Inc. (KMI) management on the conference call** – KMI management specifically mentioned that Terasen Gas is a stand-alone operating company and will continue to operate that way post acquisition.
- **Current Terasen holdco may be replaced with a new wholly owned Canadian subsidiary of KMI** – management said on the conference call that KMI will establish a wholly owned Canadian subsidiary to hold all of Terasen's opcos. On a follow-up call to KMI, we confirmed that current plan is for this new Canadian subsidiary of KMI to replace the existing Terasen Inc. holdco. **What is uncertain is whether or not the three bond issues currently at Terasen Inc. (i.e. 6.3% 2008, 4.85% 2006, and 5.56% 2014) will be held by the new subsidiary or will be consolidated as KMI bonds.** At the time of our telephone conversation, KMI's investor relations were not able to give us a definitive answer to this question.

Trevor Bateman, CFA, CA	Phillip Armstrong	Kevin Yong, CFA	Joanna Zapior, CFA, CMC
(416) 594-7992	(416) 956-3272	(416) 956-6273	(416) 594-8498
Banks, Non-bank financials, Autos, ABS	Telecom, Cable, Insurance, Retail, Consumer Products	Oil & Gas, Utilities, Aerospace	Strategy

Dina Giacomelli –Editor **(416) 956-6056**

CIBC World Markets Inc. PO Box 500, 161 Bay Street, BCE Place, Toronto, Canada M5J 2S8 Bloomberg@wgec1 **(416) 594-7000**
CIBC World Markets Corp. 300 Madison Avenue, New York, NY 10017 **(212) 856-4000, (800) 999-6726**

- **KMI will have to finance this acquisition with about US$2 billion in debt –** which KMI expects to financed with a bridge facility and then terming this facility out with a long-term bond issue. Management said that the **current plan calls for the new Canadian subsidiary to issue public bonds to repay the bridge facility upon closing of the transaction.** The uncertainty (again KMI investor relations could not shed any light on this on the phone) is in what market KMI will issue the new bonds. It may be a C$ bond issue, or a US$ bond issue, or it may be a combination of both. Additionally, future debt financing for growth projects of the Canadian assets will be issued from this new subsidiary. If the entire amount is issued in Canada at once, then we may see spread weakness.

- **Ratings may be at risk –** both KMI and Terasen have talked to the rating agencies about the transaction. Terasen said that the rating agencies have all the details of the transaction, including the plan to maintain debt at the opco level and operating autonomy of the opcos. Given the big difference in ratings between KMI and Terasen, it would not be a surprise to see a rating agency like Moody's downgrading the ratings of Terasen opco bonds in order to close the ratings gap between KMI and Terasen.

- **KMI likes gas LDC business and cannot roll these assets down to its MLP –** KMI management said that it likes Terasen's gas LDCs (Terasen Gas and Terasen Gas Vancouver Island) and expects to keep these natural gas LDCs rather than selling them. KMI is also legally not able to roll these assets down into its MLP (Kinder Morgan Energy Partners, which BBB+ rated, is a publicly traded master limited partnership), as gas distribution businesses are excluded from MLP qualified business activities.

- **Canadian pipeline assets not tax efficient for MLP roll-down –** management said that it would not be tax efficient for KMI to roll-down Terasen's Canadian pipeline assets into its MLP. The reason is that these Canadian assets still have to pay Canadian taxes even if they were in a U.S. MLP. That said though, management did not rule out putting the U.S. portion of Express and Platte into KMI's MLP. Also, management said that income trust for the Canadian pipeline assets is another option but that it was too early to say definitively what their plans will be for the Canadian pipeline assets.

- **Future growth plans in Canada –** KMI's growth plans in Canada will likely be focused on pipeline expansions, terminal expansions in Alberta, and potential growth of a CO_2 pipeline in Alberta. Management said that outside of steady organic growth, it does not have big growth plans for Terasen's gas distribution businesses.

Please refer to Our Opinions table (below) to place this credit in its sector-relative-value context

26-Jul-05	Analyst	Senior unsecured DBRS	Moody's	S&P	Credit fundamentals (1-3 years)	Rating change probab. (1 year)	Valuation	YTD total return: Shorter bond: Bond	Return	Longer bond: Bond	Return	YTD change in spread: Shorter bond: Curr Sprd	YTD Chng	Longer bond: Curr Sprd	YTD Chng
Pipelines: *Solid, largely regulated fundamentals, though regulatory environment disadvantages those companies that have North American growth plans as Cdn leverage is higher and returns lower. Our investment thesis rests on two pillars: 1) operating excellence and cost management will be key in light of 2) regulators pressuring for cost control, including returns. Holding company risk has been increasing with expansion in non-regulated areas, equity market push for growth, and still elevated leverage.*															
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Enbridge Inc	KY	A	A3	A-	May weaken (M&A, projects)	Medium	C	5.8% 2008	2.59%	8.2% 2024	8.73%	32	▼ 4	90	▼ 11
Enbridge Pipelines	KY	A(high)	NR	A-	Stable	Medium	R	5.621% 2007	1.86%	7.2% 2032	10.70%	29	▼ 1	116	▼ 9
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Negative outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand. We think that short-term acquisition risk is reduced with the announced sale of TransCanada Power LP interests to EPCOR, which should improve TRP's cash outlook w and balance sheet capacity when the transaction closes. Management's commitment to maintain TRP's "A" rating also mitigates short-term risks associated with acquisitions. We read this to mean that TRP will likely make acquisitions in a conservative way (ce sheet not be a detriment to bondholders). The improved balance sheet and renewed commitment to its "A" rating gives us more comfort that TRP's credit quality may not deteriorate if it were to make a large acquisition in the near-term.

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MNEP	KY	A	A1 UR-PD	A	Strong	Very low	F	NA	NA	6.9% 2019	6.57%	NA	NA	63	▼ 17

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Emera	KY	BBB(high)	Baa2	BBB+ Neg	May weaken	Medium	R	NA	NA	NA	NA	NA	NA	NA	NA
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Our Ratings

Market Perform The issuer's bonds are expected to perform in line with our universe of bonds over the next 12 months

Outperform The issuer's bonds are expected to outperform our universe of bonds over the next 12 months.

Underperform The issuer's bonds are expected to underperform our universe of bonds over the next 12 months

Rating Category	CIBC WM - CDR Universe (equally weighted)
Outperform	38%
Market Perform	46%
Underperform	15%

Tuesday, August 02, 2005

CIBCWM Bond Rating:

Market Perform

Credit Ratings: Terasen Inc.

S&P: BBB-/Stable

Moody's: A3/Stable

DBRS: A (low)/Stable

Credit Ratings: Terasen Gas

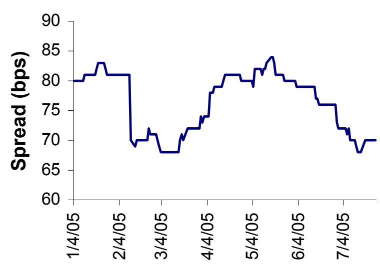
S&P: BBB/Stable

Moody's: A2/Stable

DBRS: A/Stable

Bond Spreads

TER 5.56% 9/15/2014



Source: CIBC World Markets

Kevin Yong

416-956-6273
kevin.yong@cibc.ca

Joanna Zapior

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Pipelines & Utilities

Terasen Inc.

Kinder Morgan to acquire Terasen Inc.

OUR INITIAL TAKE: Negative from a ratings perspective but neutral from a credit perspective. Kinder Morgan (KMI) is rated BBB/stable by S&P, Moody's, and DBRS, and Fitch rates KMI BBB/Positive. From a credit perspective, KMI has lower leverage and higher coverage ratios than Terasen. Although, KMI has a better financial profile than Terasen, its business risk profile is higher risk than Terasen's. As such, we think that the better financial risk profile is offset by the higher risk profile of KMI and this transaction should be credit neutral.

- **KMI has a better financial profile than Terasen** – KMI ended 2004 with a debt to capital of about 43%, total debt to cash flow of 5x, and EBIT coverage of about 5.6x. By comparison, Terasen ended 2004 with a debt to capital of 68%, total debt to cash flow of almost 10x, and EBIT coverage of 2.4x.
- **KMI has a higher risk business profile than Terasen** – KMI operates predominantly regulated and fee-based energy infrastructure businesses in the U.S. Rocky Mountains and mid-continent regions of the U.S. KMI's assets consists of Natural Gas Pipeline Company of America (which is the largest transporter of natural gas in the Chicago area), small retail natural gas distribution, power assets, and ownership in Kinder Morgan Energy Partners, L.P. (a publicly traded master limited partnership that owns and operates a diverse portfolio of largely fee-based pipelines and midstream energy assets.
- **KMI has high management ownership** – KMI is 23% owned by management.

Details of the transaction:

- KMI proposes to acquire all common shares and assume all debt of Terasen Inc.
- Annual dividend of KMI is expected to rise US$3.50 in 2006 from a current dividend of US$3.00. This is significant as KMI's high payout ratio is a credit concern.
- Upon closing of the transaction the total debt to capital ratio of KMI is expected by management to increase to about 56%. Management expects that KMI will be able to retain its BBB rating upon closing of the transaction.
- Transaction will require the approval of 75% of Terasen shareholders, who will vote at a special meeting to be held on or before October 31, 2005.
- KMI is offering to acquire Terasen for C$35.91 per share, which represents a 14% premium on Friday's closing price. The offer is for a combination of shares and cash (65% cash and 35% shares).
- Terasen has an agreed to a break-fee of C$75 million.
- Terasen conference call at 10 AM at 1-877-375-5688. KMI has a conference call at 8 AM (web cast at www.kindermorgan.com).

Please refer to Our Opinions table (below) to place this credit in its sector-relative-value context

26-Jul-05	Analyst	Senior unsecured DBRS	Senior unsecured Moody's	Senior unsecured S&P	Credit fundamentals (1-3 years)	Rating change probab. (1 year)	Valuation	YTD total return: Shorter bond Bond	Shorter bond Return	Longer bond Bond	Longer bond Return	YTD change in spread: Shorter bond Curr Sprd	Shorter bond YTD Chng	Longer bond Curr Sprd	Longer bond YTD Chng
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Enbridge Gas Dist.	KY	A	NR	A-	Stable	Medium	R	11.15% 2009	2.96%	6.1% 2028	9.77%	55	▲ 4	95	▼ 6
Alliance Pipe	KY	A(low)	A3	BBB+	Strong	Very low	F	7.23% 2015	4.76%	7.217% 2025	5.82%	36	▼ 27	91	▼ 8
There are continued M&A and large project risks - lots of noise in the news as jockeying for positions continues. The market now prices its uncertainty about committment to "A" ratings. Pipe acquisition in the GoM has eroded current balance sheet to the lecontinued permissible under the S&P rating. Over time, we see balance sheet quality potentially weakening as more risky assets may be added while mature, stable assets end up in income trust. That it has historically been a defensive credit (low spread volatility) under the pause but history may not repeat itself. We view **opcos** as better credits in line with DBRS logic but not necessarily better value. Note **EGD** has a 2006 rate case. Regulatory stability has improved after a recent spate of decisions & PBR is possible. Mainline negotiated ITS is complete and is neutral to slightly positive from a credit perspective. For **Alliance,** we like the "structuring premium" of an amortizer and the simplicity of this credit; not affected by how the ownership is structured; valuation reflects the defensive nature of this credit. It continues to perform as expected. Mgt turnover has been signficant (CFO earlier and now CEO) but this has no credit impact either for this contractually structured credit															
TransCanada	KY	A	A2	A- Neg	Stable but event risk	Medium	F	6.05% 2007	1.94%	6.5% 2030	9.36%	30	▼ 6	115	↔ 0
Negative outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand. We think that short-term acquisition risk is reduced with the announced sale of TransCanada Power LP interests to EPCOR, which should improve TRP's cash outlook w and balance sheet capacity when the transaction closes. Management's commitment to maintain TRP's "A" rating also mitigates short-term risks associated with acquisitions. We read this to mean that TRP will likely make acquisitions in a conservative way (ce sheet not be a detriment to bondholders). The improved balance sheet and renewed commitment to its "A" rating gives us more comfort that TRP's credit quality may not deteriorate if it were to make a large acquisition in the near-term.															
Duke (Westcoast)	KY	A(low) UR-Dev	NR	BBB CW-Neg	Improving	Low	R	5.7% 2008	2.74%	7.15% 2031	8.29%	38	▼ 8	131	▲ 8
Duke (Union Gas)	KY	A UR-Dev	NR	BBB CW-Neg	Standalone stbl + DUK effect	Low	R	5.7% 2008	2.67%	8.65% 2025	7.85%	36	▼ 5	118	▲ 4
MNEP	KY	A	A1 UR-PD	A	Strong	Very low	F	NA	NA	6.9% 2019	6.57%	NA	NA	63	▼ 17
The announced merger with Cinergy should take some of the growth pressures off management, which is good for bondholders. Also good for bondholders in that this is an all stock deal and Cinergy's merchant assets (which is mostly coal) should diversify thenounce risks. Although S&P agrees with us that the transaction in itself is not a detriment to credit, it nevertheless put Duke on credit watch negative because of the uncertainty with regards to what Duke mgmt may do post merger - namely possibility of separatiS&P agrees with and unregulated utilities. We believe the separation of the regulated and unregulated businesses may actually be good for credit ratings of Westcoast and Union Gas. However, in the event that nothing happens post merger and Duke remains whole, as it is nunre ratings of Westcoast and Union Gas should remain unchanged. Of greater concern should be the talk of spinning out the Westcoast assets into an income trust, which we believe could be a mild negative (depending on how the trust is structured) for Westcoasta bondholders. Union Gas for now is not expected to be put into an income trust. For **MNEP**, we like structural protection and simplicity; valuation reflects the defensive nature of this credit.															
Terasen	KY	A(low)	A3	BBB-	Stable but some event risk	Low	F	6.3% 2008	3.13%	NA	NA	46	▼ 12	NA	NA
Terasen Gas	KY	A	A2	BBB	Stable	Low	F	NA	NA	6.95% 2029	10.74%	NA	NA	118	▼ 11
Business fundamentals are a strong combination of a regulated gas distribution and pipelines, with aggressive financial profile. Although to be fair, we note that most of TER's consolidated debt resides at INL, which is a regulated utility that is restricts are a strong combi equity it can have in its capital structure by the BCUC. BCUC's allowed equity cushion for gas utilities is among the lowest in Canada. We also like the relatively conservative near-term growth of TER, with most of the growth focused on adding to regulatn have in it With ENB getting a new ITS, attention now is on Trans Mountain's ITS. We think that Trans Mountain's ROE will fall but not back to the allowed ROE. Producers will likely give Trans Mountain chances to make up most of the rebased earnings with incentives.B getti new ITS will have greater impact on TER's consolidated cash flow and credit metrics because all of Trans Mountain is under the current ITS.															
Integrated electric: *A mixed bag of companies, ranging from trasnmission dominated, through fully integrated but in a regulated setting, to a mix of regulated T&D and non-regualated generation, and even E&P. Hence risk profiles vary and the companies in this group are not direct comparables.*															
Emera	KY	BBB(high)	Baa2	BBB+ Neg	May weaken	Medium	R	NA	NA	NA	NA	NA	NA	NA	NA
Nova Scotia Power	KY	A(low)	Baa1	BBB+ Neg	May weaken	Medium	R	5.55% 2009	3.46%	8.85% 2025	8.78%	43	▼ 5	130	▲ 1
The negative regulatory decision for NSP that disallowed fuel adjustment clause and granted lower allowed ROE than anticipated is a negative for credit and may lead to increase rating risk. The potential negative cash flow impact of this decision means th regulatory increased risk that Emera will not be able to hit the credit metric targets that S&P has set for the company. Furthermore, the negative decision underscores the fact that NSP's relationship with its regulator has taken a step backwards rather than our expthat Emera will this relationship would improve. NSP recently filed 2006 rate case seeking 15% increase in rates in order to recover significant increase in fuel expense. We don't think that they will get the full amount, which puts NSP's cash flow and credit metrics atuld improve. NSP issuer here is really NSP, but even it has scarcity value.															
EPCOR	KY	A(low)	NR	BBB+	Stable	Low	R	6.2% 2008	2.96%	6.8% 2029	11.11%	37	▼ 10	118	▼ 9
Credit fundamentals (i.e. credit metrics and tighter management) and lack of liquidity in the bond are positive for spreads. EPCOR's strong credit fundamentals is founded on its relatively low-risk business profile and a very strong balance sheet (end of 1s (i.e. credit met these positives are continued soft electricity market in Alberta, increased merchant exposure, and event risk related to renewed focus on growth. We see EPCOR's recent acquisiton of TransCanada's interest in TransCanada Power LP as neutral for bondholderse po these assets are bondholder-friendly and this acquisition was small enough to not have a material negative impact on EPCOR's balance sheet in 2005. The risk here is that management may not be done with growth yet.															

Legal Disclaimers and Important Disclosure Footnotes

Important disclosures, including potential conflict of interest information, our system for rating investment opportunities and our dissemination policy can be obtained by visiting CIBC on the web at

http://research.cibcwm.com/res/Policies/Policies.html

or write to CIBC World Markets Inc. BCE Place, 161 Bay Street, 4th Floor, Toronto, Ontario M5J 2S8, Attention: Research Disclosures Request.

Our Ratings

Market Perform The issuer's bonds are expected to perform in line with our universe of bonds over the next 12 months

Outperform The issuer's bonds are expected to outperform our universe of bonds over the next 12 months.

Underperform The issuer's bonds are expected to underperform our universe of bonds over the next 12 months

Rating Category	CIBC WM - CDR Universe (equally weighted)
Outperform	38%
Market Perform	46%
Underperform	15%

Buy. Debt levels remain the principal knock in the credit markets against **Terasen Inc. (A(low)/ BBB-(pi)/ A3)** and its operating subsidiaries. The very thin deemed equity capitalization of its regulated gas distribution operations is the main driver of consolidated leverage. This leverage translates into weak credit ratios, with FFO interest coverage of just 2.8x in 2004, and only moderate prospects for improvement. Leverage appears to be the principal reason for the lowly "public information only" rating from S&P, which we think is far too conservative, but which we also acknowledge is unlikely to change. Apart from leverage, however, we see much to like in Terasen's businesses. All of its operating units exhibit very good stability of earnings, which is crucial to managing with leverage. Diversification is increasingly broad, with 2004 earnings split 56% from gas distribution, 40% from petroleum transportation, and 5% from water utility services. Compared to peers Enbridge and TransCanada PipeLines, we think Terasen's event risk is slightly lower, as we see Terasen management as less aggressive with acquisitions, and Terasen has a much lower likelihood of major participation in the big-ticket Alaska or Mackenzie Valley gas pipeline construction projects. Even if the big TMX project proceeds, it has distinct stages, and thus in our view less risk, than a one-shot line from Alberta to the West Coast of B.C. We see Terasen management's 6% earnings growth target as achievable with low-risk, incremental growth. In our judgement, these credit-positive features of Terasen compensate for most of its leverage handicap, and the roughly 10 bps of spread pickup over its peers make it, in our view, good value, in the context of today's expensive corporate market.

Gas Distribution

Terasen's current thrust in the gas distribution business is towards achieving operational efficiency gains. In particular, the company has already declared progress on "…improved operating efficiencies … through the ongoing integration of Terasen Gas and Terasen Gas Vancouver Island." This initiative brings to our mind a Toronto operations centre facilities tour staged in 2003 by sectoral peer Enbridge Gas Distribution, which left us very favourably impressed. The tour demonstrated what we see as solid, practical potential for operational efficiency gains in the gas distribution sector, opened up by the innovative application of modern information and communications technology, as well as other technical innovations. We believe similar applications are available to Terasen Gas Inc. and Terasen Gas Vancouver Island Inc. (TGVI), beyond the more direct synergies available on operational amalgamation of the two organizations. We note that an increasing amount of the efficiency gains must be shared with consumers under the multi-year performance based regulation settlement approved for 2004-2008 by the BCUC. The risk that efficiency gains could fail to meet targets, thereby lowering ROEs and interest coverage ratios, is a risk we take seriously, and it has been mentioned most recently by DBRS in its report on Terasen Gas this week. However, we think this risk is tempered by the ability to use technology to drive productivity in the sector.

TGVI has for some time pursued a project to increase natural gas capacity on Vancouver Island. TGVI's current proposal is for a compression facility with an adjacent LNG storage facility, with up to 1 billion cubic feet storage capacity. This would allow storage of gas shipped to the island during the off-peak season, and allow more efficient use of existing pipeline transmission capacity to the island. In February, the British Columbia Utilities Commission gave conditional approval to the LNG facility. The conditions included signing a long-term transportation service agreement with BC Hydro. BC Hydro, in turn, was to be the offtaker of the proposed Duke Point gas-fired power plant on Vancouver Island. Last week, BC Hydro abandoned the Duke Point project, as legal impediments achieved by the opposition of environmental activist groups had introduced delays that jeopardized the project's targeted 2007-2008 availability date. At present, it appears that the cancellation of Duke Point will delay TGVI's proposed LNG facility, perhaps by one to three years. TGVI will thus have a scaled-back capex program over the next few years, though some amounts (we believe less than $50 million) will probably be spent to allow the island's existing natural gas-fired electricity generation plant to shift towards base load operation (from peaking operation), to help meet electricity demand prior to BC Hydro's installation of a new electric transmission cable, probably in 2008. Part of BC Hydro's back-up plan to ensure electric system reliability on the Island until the new transmission cable is operative may include curtailment of industrial loads, though we understand that this curtailment will probably not stimulate near-term natural gas demand. Terasen believes that the LNG facility remains desirable to meet medium-term demand for natural gas on Vancouver Island, and we think the company will approach the regulator with a similar storage facility proposal at some future date.

Petroleum Transportation

Terasen has a one-third share in the Express pipeline, and is the operating partner. The Express expansion was completed on time, and a little under budget, in April, representing a capacity increase (on Express) of over

60%. The capital cost was about US$100 million, and was entirely debt financed through the $110 million US market debt issue last July. The earnings impact should be evident in Q2 results, and should annualize to about $5 million, or a 3% increase in Terasen's consolidated earnings. Express earnings are sensitive to changes in throughput, subject to a floor provided by ship-or-pay contracts for most of its capacity. Q1 throughputs on Express were weak, affected by temporary interruptions in Albertan oil sands production, notably at Suncor, though Q2 should show improvement.

The Trans-Mountain pipeline also saw lower volumes in Q1 due to Alberta production outages, but should also rebound in Q2. The Corridor pipeline is contracted (primarily to Shell Canada) on a ship-or-pay basis, and its earnings are not sensitive to throughput. Terasen continues to work with Shell towards a capacity expansion of Corridor from the current 155,000 bpd, which would occur in stages. The first of these, already approved by shippers, is a simple pumping capacity upgrade, good for an incremental 35,000 bpd for only $6.5 million. The second is a much larger expansion, for roughly $800 to $900 million. It is as yet unapproved, but could be available for service as soon as 2009.

Terasen management continues development work on the TMX proposal. Should Enbridge's Gateway proposal prevail, we would not view the "loss" as negative for Terasen credit quality. Nonetheless, we continue to think the staged nature of TMX probably makes it a less risky project from a credit perspective than a single-stage Edmonton to West Coast B.C. alternative (subject, of course, to financing, contracting, and other details).

Water

Terasen's water segment's second and third quarters (the strongest quarters seasonally) should see materially higher earnings this year, reflecting the inclusion of the Fairbanks, Alaska water utility's results. The Fairbanks acquisition, for US$30 million, closed on August 1, 2004. Management expects about one-third of Terasen's targeted average 6% future earnings growth will come from water utilities. We continue to think that the acquisition of assets in the sector is at present politically contentious among some interest groups in Canada, and even in the U.S. Nonetheless, we also think that Terasen should be able to appeal to some municipal councils by offering efficient, effective, consistently high-quality facility management, and thus expand its business gradually, with fairly small, low-risk capital or operating contracts, or acquisitions. Terasen has allocated up to $50 million of its capital plan for 2005 to the sector, though the availability and attractiveness of opportunities will always be hard to predict, and we anticipate "lumpy" growth for the segment. We note EPCOR's valuable water utility business (which contributed 27% of 2004 earnings), and we continue to view the water business line as a very attractive, diversifying complement to Terasen's gas distribution and petroleum transportation core business lines.

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Terasen Inc.

(TER-TSX)

Stock Rating: Underperform
Industry Rating: Market Perform

February 1, 2005
Research Comment
Pipelines

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

Preliminary Interest in TMX - Phase I; Underperform Rating Unchanged

Event

Terasen Pipelines (100% - Terasen Inc.) has announced that it has received favourable preliminary interest from potential shippers on the planned, phased expansion of the Trans Mountain Pipeline. The first phase of expansion, TMx1, would increase the capacity by 75,000 bbls/d to 300,000 bbls/d at a total cost of $570 million; 35,000 bbls/d of incremental capacity would be added by late 2006 at a planned cost of $205 million and involve the installation of additional pump stations; and a further 40,000 bbls/d would be added by late 2008, at a cost of $365 million and involve the construction of a pipeline loop. Terasen has received sufficient shipper interest to continue with its development effort on the TMx expansion, and we expect a further open-season process to obtain term, unconditional shipping agreements by mid-2005.

Impact

Potentially positive.

Forecasts

No change. We have incorporated the first portion of TMx1 into our financial model, however: (1) definitive transportation agreements and regulatory approvals have not yet been obtained; and (2) terms of the new incentive agreement governing the Trans Mountain pipeline commencing January 1, 2006 are not yet known, and the potential contribution from the expansion is unknown.

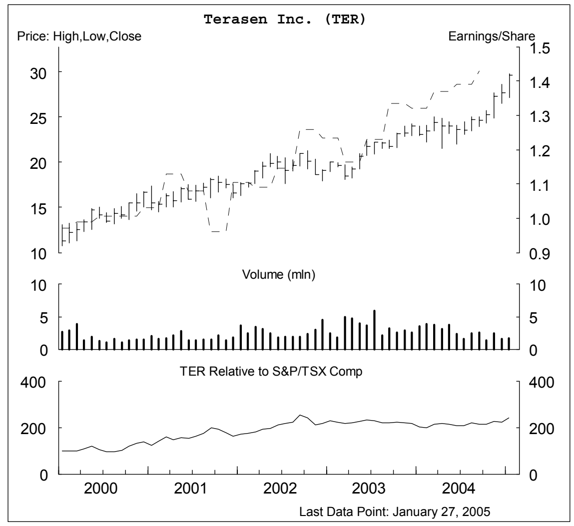
Valuation

Our target price reflects a weighted average valuation approach: 15x diluted 2006 EPS of $1.53 (12.5%), 1.75x 2006E book value of $14.29 (12.5%), and a target yield of 3.25% (75%), assuming 2005 dividends per share of $0.91.

Recommendation

We believe that the shares are fully valued and we rate them Underperform.

Price (28-Jan)	$29.02	**52-Week High**	$29.79
Target Price	$27.00	**52-Week Low**	$21.50



(FY-Dec.)	2003A	2004E	2005E	2006E
EPS	$1.28	$1.40	$1.49	$1.53
P/E		20.7x	19.5x	19.0x
CFPS	$2.58	$2.39	$2.48	$2.54
P/CFPS		12.2x	11.7x	11.4x
Div.	$0.77	$0.83	$0.87	$0.91
EV ($mm)	$5,296	$6,113	$6,143	$6,139
EBITDA ($mm)	$503	$546	$575	$589
EV/EBITDA	10.5x	11.2x	10.7x	10.4x

Quarterly EPS	Q1	Q2	Q3	Q4
2003A	$0.71	$0.08	-$0.07	$0.60
2004E	$0.76a	$0.10a	-$0.03a	$0.59
2005E	$0.81	$0.10	-$0.03	$0.61

Dividend	$0.84	**Yield**	2.9%
Book Value	$13.29	**Price/Book**	2.2x
Shares O/S (mm)	104.7	**Mkt. Cap ($mm)**	$3,038
Float O/S (mm)	104.7	**Float Cap ($mm)**	$3,038
Wkly Vol (000s)	597	**Wkly $ Vol (mm)**	$14.7
Net Debt ($mm)	$3,137.3	**Next Rep. Date**	17-Feb (E)

Notes: Quarterlies reflect timing of equity issues
Major Shareholders: Widely held
First Call Mean Estimates: TERASEN INC. (C$) 2004E: $1.41; 2005E: $1.51; 2006E: $1.56

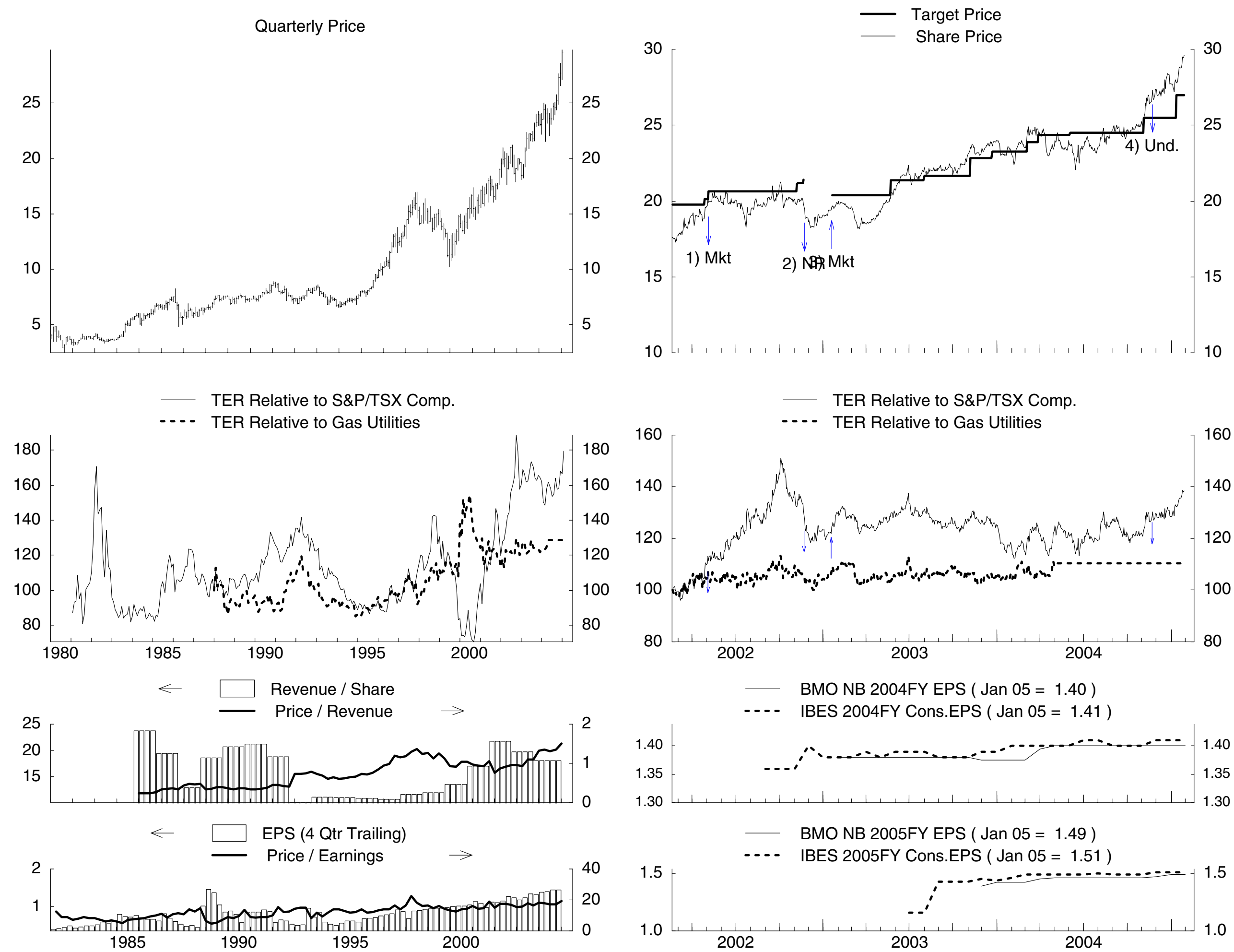
Please refer to pages 3 to 5 for Disclosure Statements, including the Analyst's Certification.

Table 1. Consolidated Summary Sheet

1/31/2005	Karen J. Taylor
Current Price: $29.35	BMO Nesbitt Burns Inc
12-Month Target Price: $27.00	
Rate of Return: -5.04%	Rating: Underperform

	Year Ending December 31							
	1999	**2000**	**2001**	**2002**	**2003**	**2004E**	**2005E**	**2006E**
Diluted EPS (Prior to One-Time Items)	$0.96	$0.99	$1.01	$1.26	$1.28	$1.40	$1.49	$1.53
Total EPS (Prior to One-Time Items)	$0.97	$1.00	$1.02	$1.27	$1.29	$1.41	$1.50	$1.55
Segmented EPS: Terasen Gas Utility	$0.68	$0.77	$0.89	$1.07	$0.93	$0.94	$0.95	$0.95
Trans Mountain Pipe Line	$0.26	$0.25	$0.27	$0.34	$0.54	$0.66	$0.69	$0.70
Water/Other Businesses	$0.04	($0.02)	($0.14)	($0.14)	($0.18)	($0.19)	($0.14)	($0.10)
Corporate Activities	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dividends	$0.58	$0.61	$0.65	$0.69	$0.77	$0.83	$0.87	$0.91
Payout Ratio	60.1%	61.3%	63.7%	54.5%	59.3%	58.5%	58.0%	58.7%
Average Shares (mm)	76.6	76.6	76.6	86.4	103.8	104.7	104.7	104.7
Net Book Value	$8.31	$9.02	$9.39	$12.10	$12.44	$13.02	$13.65	$14.29
Market Valuation								
Price: High	$15.50	$16.73	$18.20	$21.25	$24.00	$28.40	-	-
Price: Low	$10.50	$10.75	$14.88	$16.32	$18.18	$22.05	-	-
Price: Current	-	-	-	-	-	-	$29.35	-
P/E Ratio: High	16.0	16.24	17.84	16.73	18.60	20.14	-	-
P/E Ratio: Low	10.8	10.44	14.58	12.85	14.09	15.64	-	-
P/E Ratio: Current	-	-	-	-	-	-	19.6	18.9
Price/Book Value: High	1.92	1.85	1.94	1.76	1.93	2.18	-	-
Price/Book Value: Low	1.30	1.19	1.58	1.35	1.46	1.69	-	-
Price/Book Value: Current	-	-	-	-	-	-	2.15	2.05
Yield: High Price	3.76%	3.66%	3.57%	3.26%	3.19%	2.90%	-	-
Yield: Low Price	5.55%	5.70%	4.37%	4.24%	4.21%	3.74%	-	-
Yield: Current Price	-	-	-	-	-	-	2.96%	3.10%
Balance Sheet ($mm)								
Debt (S-T)	508.5	314.2	528.4	426.2	610.0	779.3	1,647.2	1,649.3
Debt (L-T)	1,001.8	1,561.9	1,928.0	2,123.4	2,301.1	2,174.9	1,336.0	1,533.7
Deferred Taxes	35.0	47.3	56.8	58.1	67.5	58.1	58.1	58.1
Minority Interest	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Securities	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Shareholders' Equity	645.1	701.5	718.7	1,244.5	1,302.3	1,363.4	1,429.4	1,495.6
	2,265.4	2,749.9	3,356.9	3,977.2	4,405.9	4,500.7	4,595.8	4,861.7
Balance Sheet (%)								
Debt (S-T)	22.4%	11.4%	15.7%	10.7%	13.8%	17.3%	35.8%	33.9%
Debt (L-T)	44.2%	56.8%	57.4%	53.4%	52.2%	48.3%	29.1%	31.5%
Deferred Taxes	1.5%	1.7%	1.7%	1.5%	1.5%	1.3%	1.3%	1.2%
Minority Interest	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred Securities	0.0%	4.5%	3.7%	3.1%	2.8%	2.8%	2.7%	2.6%
Shareholders' Equity	28.5%	25.5%	21.4%	31.3%	29.6%	30.3%	31.1%	30.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Income Statement ($mm)								
Net Profit After-Tax	82.8	80.7	77.9	109.5	133.9	147.5	157.1	161.4
Preferred Share Dividends	8.7	4.0	0.0	0.0	0.0	0.0	0.0	0.0
Earnings to Common Shareholders	74.1	76.7	77.9	109.5	133.9	147.5	157.1	161.4
Cash Flow from Operations ($mm)	117.0	173.3	53.6	311.4	267.7	250.0	263.3	270.5

Terasen Inc. (TER)



FYE (Dec.)	EPS $	P/E	DPS $	Yield %	Payout %	BV $	P/B	ROE %
1982	0.48	7	0.28	8.1	58	3.01	1.1	16
1983	0.48	8	0.28	7.0	58	3.47	1.1	15
1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
Current*	1.43	19	0.84	3.0	59	13.29	2.1	11
Average:		12		5.1	59		1.5	13.9
Growth(%):								
5 Year:	8.1		7.3			10.2		
10 Year:	11.4		6.4			7.2		
20 Year:	4.4		5.7			6.7		

* Current EPS is the 4 Quarter Trailing to Q3/2004.

TER - Rating as of 18-Feb-02 = OP

	Date	Rating Change	Share Price
1	3-May-02	OP to Mkt	$20.25
2	21-Nov-02	Mkt to NR	$19.76
3	17-Jan-03	NR to Mkt	$19.39
4	23-Nov-04	Mkt to Und.	$26.95

Last Daily Data Point: January 27, 2005

Company Risk Disclosure

In addition to the risks involved in investing in common stocks generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

General Disclosure

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Company Specific Disclosure

Disclosure 2: BMO Nesbitt Burns has undertaken an underwriting liability with respect to this issuer within the past 12 months.

Disclosure 3: BMO Nesbitt Burns has provided investment banking services with respect to this issuer within the past 12 months.

Disclosure 10: This issuer is a client (or was a client) of BMO Nesbitt Burns, HNC or an affiliate within the past 12 months: Investment Banking Services.

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Rating Category	BMO NB Rating	BMO NB Universe	BMO NB I.B. Clients*	First Call Universe**
Buy	Outperform	37%	39%	45%
Hold	Market Perform	48%	47%	47%
Sell	Underperform	15%	14%	8%

* Reflects rating distribution of all companies where BMO NB has received compensation for Investment Banking services.
** Reflects rating distribution of all North American equity research analysts.

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^ Market performance as measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company.

Prior to September 1, 2003, a fourth rating tier—Top Pick—was used to designate those stocks we felt would be the best performers relative to the market. Our six Top 15 lists which guide investors to our best ideas according to six different objectives (large, small, growth, value, income and quantitative) have replaced the Top Pick rating.

Dissemination of Research

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Additional Matters

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Terasen Inc.

(TER-TSX)

Stock Rating: Underperform
Industry Rating: Market Perform

May 5, 2005
Research Comment
Pipelines

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

Q1/05 EPS Moderately Lower Than Expected; Underperform Rating Maintained

Event

Terasen reported Q1/05 EPS of $0.63 (basic) per share. After adjusting for the positive affect of a mark-to-market gain on Clean Energy's (45% - Terasen Inc.) price risk management activities recorded during the quarter, reported basic EPS were $0.60, moderately lower than our expectation of $0.64 per share. The variance between expected and actual performance is largely attributable to a $0.05 per share reduction in the contribution from the Trans Mountain Liquids Pipeline System, due to production outages in Q1/05 at Syncrude and Suncor and refinery turnarounds at facilities connected to the system in British Columbia and Washington State.

Impact

Slightly negative.

Forecasts

Our 2005 and 2006 diluted EPS estimates of $1.47 and $1.55 are unchanged. We note that despite lower Q1/05 performance, management indicated that it remains comfortable with its established EPS growth rate of 6% per annum.

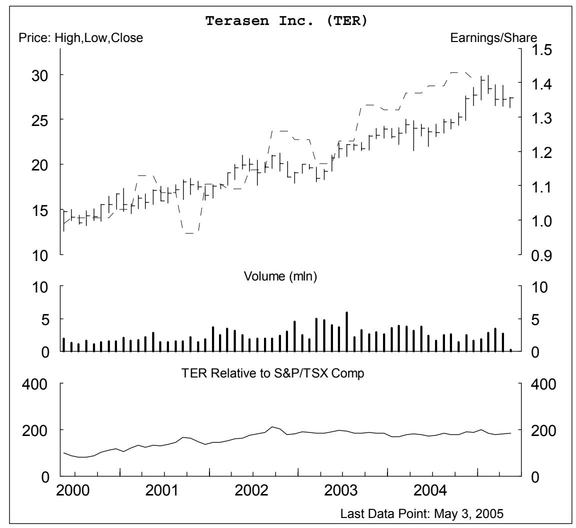
Valuation

Our target price of $27.75 reflects a weighted average valuation approach: 15x diluted 2006E EPS of $1.55 (12.5%), 1.75x 2006E book value of $14.34 (12.5%) and a target yield of 3.25% (75%), assuming 2006E dividends per share of $0.94.

Recommendation

We believe that the shares are fully valued at present levels and we rate them Underperform.

Price (4-May)	$27.45	**52-Week High**	$29.91
Target Price	$27.75	**52-Week Low**	$22.00



(FY-Dec.)	2003A	2004A	2005E	2006E
EPS	$1.28	$1.39	$1.47	$1.55
P/E			18.7x	17.7x
CFPS	$2.58	$3.27	$3.07	$3.25
P/CFPS			8.9x	8.5x
Div.	$0.77	$0.83	$0.90	$0.94
EV ($mm)	$5,296	$5,725	$6,098	$6,243
EBITDA ($mm)	$503	$521	$588	$625
EV/EBITDA	10.5x	11.0x	10.4x	10.0x

Quarterly EPS	Q1	Q2	Q3	Q4
2003A	$0.71	$0.08	-$0.07	$0.60
2004A	$0.76	$0.10	-$0.03	$0.58
2005E	$0.60a	$0.23↑	$0.09↑	$0.55

Dividend	$0.90	**Yield**	3.3%
Book Value	$13.47	**Price/Book**	2.0x
Shares O/S (mm)	105.3	**Mkt. Cap ($mm)**	$2,890
Float O/S (mm)	105.3	**Float Cap ($mm)**	$2,890
Wkly Vol (000s)	563	**Wkly $ Vol (mm)**	$14.6
Net Debt ($mm)	$3,165.7	**Next Rep. Date**	28-Jul (E)

Notes: Quarterlies reflect timing of equity issues
Major Shareholders: Widely held
First Call Mean Estimates: TERASEN INC. (C$) 2005E: $1.49; 2006E: $1.56

Changes

Quarterly EPS
Q2/05E $0.22 to $0.23
Q3/05E $0.07 to $0.09

Please refer to pages 7 to 9 for Disclosure Statements, including the Analyst's Certification.

Details & Analysis

Terasen reported Q1/05 EPS of $0.63 (basic) per share. After adjusting for the positive affect of a mark-to-market gain on Clean Energy's (45% - Terasen Inc.) price risk management activities recorded during the quarter, reported basic EPS were $0.60, moderately lower than our expectation of $0.64 per share. The variance between expected and actual performance is largely attributable to a $0.05 per share reduction in the contribution from the Trans Mountain Liquids Pipeline System, due to production outages in Q1/05 at Syncrude and Suncor and refinery turnarounds at facilities connected to the system in British Columbia and Washington State.

Q1/05 financial performance is set out in Table 1.

Table 1: Quarterly Performance by Segment

Q1/05	Earnings ($mm)			EPS		
	Q1/05	**Q1/04**	**% Chg.**	**Q1/05**	**Q1/04**	**% Chg.**
Natural Gas Distribution						
Terasen Gas	49.0	48.0	2.1%	0.47	0.46	2.2%
Terasen Gas (Vancouver Island)	6.7	6.7	0.0%	0.06	0.06	0.0%
	55.7	54.7	1.8%	0.53	0.52	1.9%
Petroleum Transportation						
Trans Mountain	5.4	10.4	-48.1%	0.05	0.10	-50.0%
Corridor	3.6	3.9	-7.7%	0.03	0.04	-25.0%
Express Pipeline	3.7	4.0	-7.5%	0.04	0.04	0.0%
	12.7	18.3	-30.6%	0.12	0.18	-33.3%
Water	0.8	-	n/a	0.01	-	n/a
Other	(5.5)	(6.8)	-19.1%	(0.06)	(0.06)	0.0%
Total	**63.7**	**66.2**	-3.8%	**0.60**	**0.64**	-6.3%

Source: Company Reports

We believe that the following remarks are relevant about Q1/05 performance:

- Average transportation volumes on the Trans Mountain and Express Pipeline systems were adversely affected by oil sands production issues: throughput on the Express System declined by 2.6% to 166,900 bbls/d and throughput on the Trans Mountain System declined by a more substantive 29.3% to average 170,00 bbls/d during the quarter. The two systems have a certain amount of volume-related income variability, due to the nature of the tolling arrangements in place:

  Trans Mountain – shipping tariffs are determined pursuant to an Incentive Tolling Agreement that expires at the end of 2005. Under this agreement, base tolls are calculated on an agreed throughput level of 189,000 bbls/d for each year of the settlement. Trans Mountain accepts the risk and benefit associated with variations in actual throughput within a defined band of 179,000 bbls/d to 201,000 bbls/d. For volumes greater than 201,000 bbls/d, Trans Mountain and its shippers share the associated benefits 50/50. If average throughput is below 179,000 bbls/d, then shippers bear 100% of the risk. Average volumes shipped on the system in Q1/05 were lower than the minimum threshold and revenues were based on a minimum ship-or-pay level of 179,000 bbls/d in the quarter.

Express – approximately 126,000 bbls/d of the initial 172,000 bbls/d of capacity is subject ship-or-pay transportation service agreements with terms through 2014 and 2015. Approximately 84% of the incremental 108,000 bbls/d of new capacity placed in-service in April 2005 is also subject to long-term ship-or-pay transportation service agreements. Approximately 77% of the 280,000 bbls/d capacity of the pipeline is now subject to ship-or-pay agreements with terms through 2012 to 2015. We note that the tariffs under the transportation service agreements are payable only if the pipeline is available to transport crude to Casper, Wyoming from Hardisty, Alberta.

- Our estimates are exclusive of mark-to-market gains and losses. We note that the company has deconsolidated Clean Energy and is now equity accounting for the entity, as a result of changes due to restructuring and amendments to voting arrangements of Clean Energy's Board of Directors. New financing expected to support the growth of the entity is expected to dilute Terasen's interest in Clean Energy, from the current level of 45% to just less than 30%. We do not assume a material contribution from Clean Energy in our estimates and we normalized for periodic mark-to-market gains and losses associated with Clean Energy's fuel risk management activities.
- Performance in the natural gas distribution segment was largely in line with expectations, as was the contribution from the Corridor Pipeline and Express Pipeline.

Estimates

Our target price of $27.75 reflects a weighted average valuation approach: 15x diluted 2006E EPS of $1.55 (12.5%), 1.75x 2006E book value of $14.34 (12.5%) and a target yield of 3.25% (75%), assuming 2006E dividends per share of $0.94. We note the following:

- The company has a robust "pipeline" of projects, as set out below in Table 2. Our estimates include the following projects: Phase I expansion of the Trans Mountain System (completed in 2004 at a cost of approximately $16 million); Express/Platte System Expansion – Phases I and II (108,000 bbls/d of incremental capacity, completed and in-service April 1 at a cost of US$100 million); Corridor Pipeline debottlenecking (in-service date of Fall 2005 and $6.5 million cost); Part 1 of the TMX1 to add pump stations to increase the capacity of the Trans Mountain System by 35,000 bbls/d by late 2006 at a cost of $205 million; and LNG storage facility at Terasen Gas Vancouver Island at a cost of $100 million by 2007/08. We do not yet assume that the Anchor TMX 1 expansion proceeds (adds 40,000 bbls/d by late 2008 at a cost of $370 million).
- We do not yet assume a contribution from the more ambitious Southern or Northern capacity increases on the Trans Mountain mainline. We expect further open seasons in the future to more definitively establish shipper need and wiliness to enter into long-term

transportation services agreement. An open season is expected in Q3/05 to determine shipper interest in the Anchor TMX 1 looping project, highlighted previously.

Table 2. Projects Under Development

Name	Expansion Volume	Cost (Millions)	In-Service Date	Estimated Contribution (Per Share)	Comments
Trans Mountain - Phase I	27,000 bbls/d	C$16	Mid-2004	$0.005	Increase Capacity to 225,000 from 200,000 bbls/d
Trans Mountain - Phase II	17,000 bbls/d	C$20	Early 2005	NA	Dropped December 8/03
Express/Platte - Phase I & II	108,000 bbls/d	US$100	Apr-05	$0.10	Increase Capacity to 280,000 from 172,000 bbls/d
Corridor Pipeline	35,000 bbls/d	C$6.5	Fall 2005	NA	Increase Capacity to 190,000 from 155,000 bbls/d; Debottlenecking
Corridor Pipeline	110,000 bbls/d	C$5-600	2009	NA	Looping of Pipeline; Third Train Muskeg to 300,000 bbls/d
Bison Pipeline	175,000 bbls/d	C$410	Post 2010	NA	New Pipeline Proposal - Dependent Upon Jackpine Mine Development
Bison Pipeline - Phase I	150,000 bbls/d	C$190	Post 2010	NA	Increase Capacity to 325,000 from 172,000 bbls/d
Bison Pipeline - Phase II	345,000 bbls/d	C$430	Post 2010	NA	Increase Capacity to 670,000 from 325,000 bbls/d
Pump Station & Anchor TMX 1	75,000 bbls/d	C$575	Late 2008	NA	Increase Capacity to 300,000 from 225,000 bbls/d; Part I 35 k bpd late '06
Southern Leg - TMPL - Loop I	100,000 bbls/d	C$1,000	Late 2009	NA	Increase Capacity to 400,000 from 300,000 bbls/d
Southern Leg - TMPL - Loop II	450,000 bbls/d	C$1,200	Late 2010	NA	Increase Capacity to 850,000 from 400,000 bbls/d
Northern Leg - Trans Mountain	550,000 bbls/d	C$2,600	Late 2010	NA	850,000 bpd capacity; 500,000 bpd to North; 350,000 bpd to South
Eastern Leg - Trans Mountain	100,000 bbls/d	C$200	2007	NA	New Capacity from Edmonton to Hardisty on Trans Mountain
Terasen Gas Vancouver Island	NA	C$20+	2007/08	$0.04	Compression on existing gas transmission line
Terasen Gas Vancouver Island	NA	C$100	2007/08	$0.06	LNG Storage Facility
Whistler Gas Pipeline	NA	C$40	NA	NA	Potential to replace existing propane system
Inland Pacific Connector	NA	C$3-500	2007/08	NA	Natural Gas; Terminum of Southern Crossing Pipeline to market hub at Sumas
Heartland Terminal	NA	C$30-$120	2006/10	NA	5-7 million bbls of tank and cavern storage

Source: BMO Nesbitt Burns, Company Reports

- Our working assumption is that Terasen will negotiate on an exclusive basis with Shell as it relates to the planned development of that company's oil sands reserves near Fort McMurray. We note Shell's April 29, 2005 announcement that it plans to develop additional mining areas on the west side of Lease 13 and on Lease 90, adding another bitumen extraction train to the existing plant and a number of debottlenecking projects. These plans would increase the capacity of the existing Muskeg River Mine from 155,000 bbls/d to about 300,000 bbls/d, assuming regulatory approval is in place by mid-2006. Combined with planned volumes from the Jackpine Mine (approved in 2004), Shell could have approvals for up to 500,000 bbls/d of bitumen. Shell's development plan would add blocks of production of approximately 100,000 bbls/d, beginning on Lease 13 in 2006, concurrent with a similar-sized expansion of the Scotfold Upgrader and debottlenecking projects. Synthetic crude production would increase by about 300,000 bbls/d by 2010.

- The final outcome of the negotiation with Terasen regarding the required pipeline facilities is likely to change the project list highlighted above, combining projects and/or eliminating certain projects.

- The tolling arrangements on the Trans Mountain facilities are unclear at present, due to the present status of the Incentive Agreement on the system. As highlighted above, the agreement expires December 31, 2005, and negotiations to implement a new agreement are not well advanced. We do not expect material discussions to begin until Enbridge's Incentive Tolling Agreement for its Mainline System is substantially in-place. We also believe that shippers may also be inclined to reflect the change in the risk profile of the liquids transportation business versus the natural gas pipeline business into new agreements. We believe that there is a material risk that 2006E EPS may be adversely affected by the outcome of this negotiation.

- The company also disclosed that it too is in discussions with Chinese companies about potential investment in a new oils sands pipeline and have letter agreements that could be construed as Memorandums of Understanding.
- We have not priced an equity issue into our financial model over the forecast period. As highlighted in the attached consolidated summary sheet, Terasen is relatively thinly capitalized and a major pipeline project may require the issuance of equity to maintain balance sheet strength.

Valuation

Our target price of $27.75 reflects a weighted average valuation approach: 15x diluted 2006E EPS of $1.55 (12.5%), 1.75x 2006E book value of $14.34 (12.5%) and a target yield of 3.25% (75%), assuming 2006E dividends per share of $0.94.

Recommendation

We believe that the shares are fully valued at present levels and we rate them Underperform.

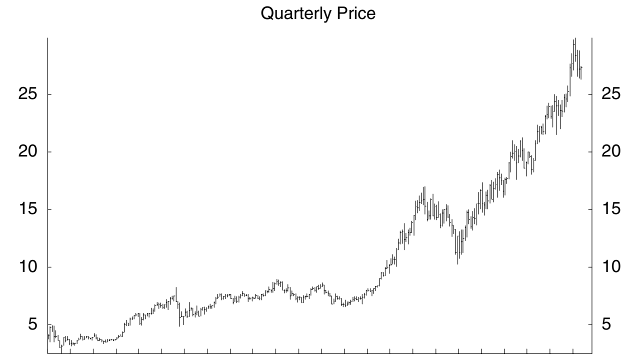
Table 3. Consolidated Summary Sheet

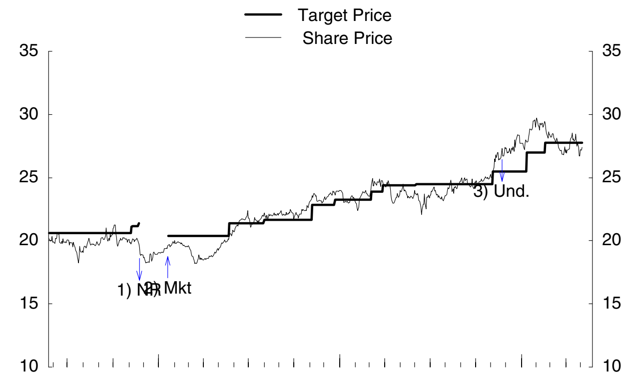
04/05/2005 — Karen J. Taylor
Current Price: $27.45 — BMO Nesbitt Burns Inc.
12-Month Target Price: $27.75
Rate of Return: 4.37% — Recommendation: Underperform

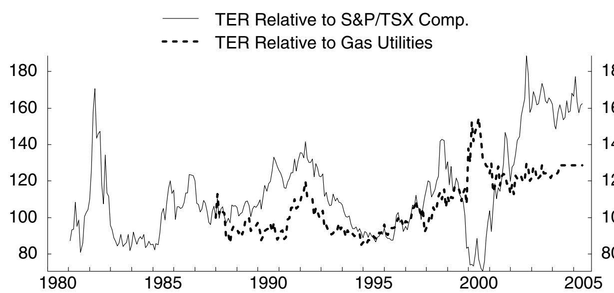
	Year Ending December 31							
	1999	**2000**	**2001**	**2002**	**2003**	**2004**	**2005E**	**2006E**
Diluted EPS (Prior to One-Time Items)	$0.96	$0.99	$1.01	$1.26	$1.28	$1.39	$1.47	$1.55
Total EPS (Prior to One-Time Items)	$0.97	$1.00	$1.02	$1.27	$1.29	$1.40	$1.48	$1.56
Segmented EPS: Terasen Gas Utility	$0.68	$0.77	$0.89	$1.07	$0.93	$0.92	$0.94	$0.97
Trans Mountain Pipe Line	$0.26	$0.25	$0.27	$0.34	$0.54	$0.68	$0.71	$0.73
Other/**Water & Utility Services**	$0.04	($0.02)	($0.14)	($0.14)	($0.18)	$0.06	$0.12	$0.15
Corporate Activities	$0.00	$0.00	$0.00	$0.00	$0.00	($0.26)	($0.30)	($0.29)
Dividends	$0.58	$0.61	$0.65	$0.69	$0.77	$0.83	$0.90	$0.94
Payout Ratio	60.1%	61.3%	63.7%	54.5%	59.3%	59.0%	60.7%	60.1%
Average Shares (mm)	76.6	76.6	76.6	86.4	103.8	104.7	105.3	105.7
Net Book Value	$8.31	$9.02	$9.39	$12.10	$12.44	$13.04	$13.67	$14.34
Market Valuation								
Price: High	$15.50	$16.73	$18.20	$21.25	$24.00	$28.40	-	-
Price: Low	$10.50	$10.75	$14.88	$16.32	$18.18	$22.05	-	-
Price: Current	-	-	-	-	-	-	$27.45	-
P/E Ratio: High	16.0	16.24	17.84	16.73	18.60	20.30	-	-
P/E Ratio: Low	10.8	10.44	14.58	12.85	14.09	15.76	-	-
P/E Ratio: Current	-	-	-	-	-	-	18.5	17.6
Price/Book Value: High	1.92	1.85	1.94	1.76	1.93	2.18	-	-
Price/Book Value: Low	1.30	1.19	1.58	1.35	1.46	1.69	-	-
Price/Book Value: Current	-	-	-	-	-	-	2.01	1.91
Yield: High Price	3.76%	3.66%	3.57%	3.26%	3.19%	2.90%	-	-
Yield: Low Price	5.55%	5.70%	4.37%	4.24%	4.21%	3.74%	-	-
Yield: Current Price	-	-	-	-	-	-	3.28%	3.42%
Balance Sheet ($mm)								
Debt (S-T)	508.5	314.2	528.4	426.2	610.0	664.7	1,424.7	1,202.8
Debt (L-T)	1,120.9	1,561.9	1,717.1	2,123.4	2,301.1	2,166.6	1,483.7	1,841.4
Deferred Taxes/Other Deferred Items	35.0	47.3	56.8	58.1	67.5	209.4	209.4	209.4
Minority Interest	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Securities	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Shareholders' Equity	645.1	701.5	718.7	1,244.5	1,302.3	1,371.1	1,442.6	1,518.5
	2,384.5	2,749.9	3,146.0	3,977.2	4,405.9	4,536.8	4,685.4	4,897.2
Balance Sheet (%)								
Debt (S-T)	21.3%	11.4%	16.8%	10.7%	13.8%	14.7%	30.4%	24.6%
Debt (L-T)	47.0%	56.8%	54.6%	53.4%	52.2%	47.8%	31.7%	37.6%
Deferred Taxes/Other Deferred Items	1.5%	1.7%	1.8%	1.5%	1.5%	4.6%	4.5%	4.3%
Minority Interest	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred Securities	0.0%	4.5%	4.0%	3.1%	2.8%	2.8%	2.7%	2.6%
Shareholders' Equity	27.1%	25.5%	22.8%	31.3%	29.6%	30.2%	30.8%	31.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Income Statement ($mm)								
Net Profit After-Tax	82.8	80.7	77.9	109.5	133.9	146.5	156.3	165.3
Preferred Share Dividends	8.7	4.0	0.0	0.0	0.0	0.0	0.0	0.0
Earnings to Common Shareholders	74.1	76.7	77.9	109.5	133.9	146.5	156.3	165.3
Cash Flow from Operations ($mm)	117.0	173.3	53.6	311.4	267.7	342.0	323.0	342.0

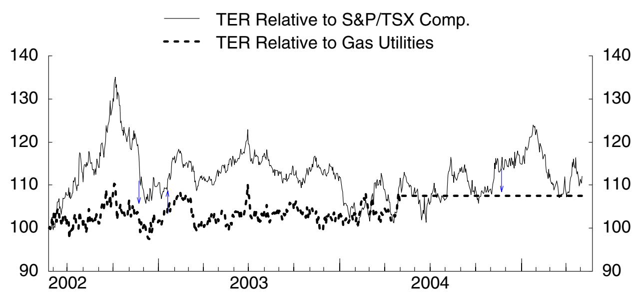
Source: BMO Nesbitt Burns

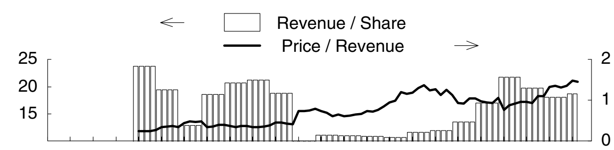
Terasen Inc. (TER)

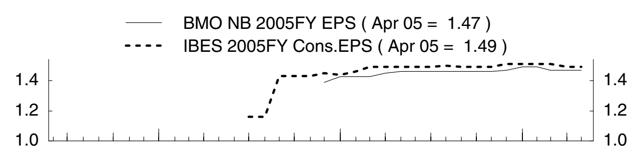


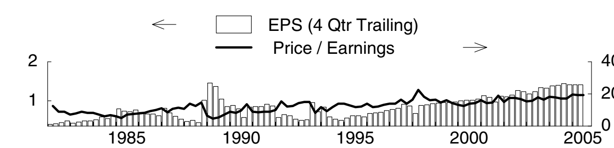


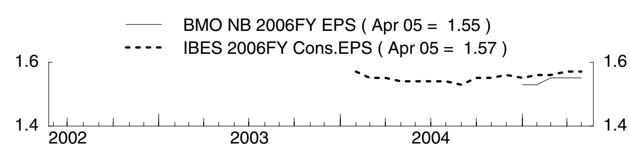












FYE (Dec.)	EPS $	P/E	DPS $	Yield %	Payout %	BV $	P/B	ROE %
1982	0.48	7	0.28	8.1	58	3.01	1.1	16
1983	0.48	8	0.28	7.0	58	3.47	1.1	15
1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
2004	1.39	20	0.84	3.0	60	13.04	2.1	11
Current*	1.41	19	0.90	3.3	64	13.04	2.1	11
Average:		13		5.0	59		1.5	13.7
Growth(%):								
5 Year:	7.3		8.8			9.8		
10 Year:	10.0		7.2			7.0		
20 Year:	3.0		5.6			6.6		

* Current EPS is the 4 Quarter Trailing to Q4/2004.

TER - Rating as of 23-May-02 = Mkt

	Date	Rating Change	Share Price
1	21-Nov-02	Mkt to NR	$19.76
2	17-Jan-03	NR to Mkt	$19.39
3	23-Nov-04	Mkt to Und.	$26.95

Last Daily Data Point: May 3, 2005

Company Risk Disclosure

In addition to the risks involved in investing in common stocks generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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Company Specific Disclosure

Disclosure 2: BMO Nesbitt Burns has undertaken an underwriting liability with respect to this issuer within the past 12 months.

Disclosure 3: BMO Nesbitt Burns has provided investment banking services with respect to this issuer within the past 12 months.

Disclosure 10: This issuer is a client (or was a client) of BMO Nesbitt Burns, HNC or an affiliate within the past 12 months: Investment Banking Services.

Distribution of Ratings

Rating Category	BMO NB Rating	BMO NB Universe	BMO NB I.B. Clients*	First Call Universe**
Buy	Outperform	37%	43%	45%
Hold	Market Perform	47%	44%	47%
Sell	Underperform	16%	13%	8%

* Reflects rating distribution of all companies where BMO NB has received compensation for Investment Banking services.

** Reflects rating distribution of all North American equity research analysts.

Ratings Key

BMO Nesbitt Burns uses the following ratings system definitions. **OP = Outperform** - Forecast to outperform the market; **Mkt = Market Perform** - Forecast to perform roughly in line with the market; **Und = Underperform** - Forecast to underperform the market; **(S) = speculative investment**; **NR = No rating at this time** - usually due to a company being in registration or coverage being initiated.

^ Market performance as measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company.

Prior to September 1, 2003, a fourth rating tier—Top Pick—was used to designate those stocks we felt would be the best performers relative to the market. Our six Top 15 lists which guide investors to our best ideas according to six different objectives (large, small, growth, value, income and quantitative) have replaced the Top Pick rating.

Dissemination of Research

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Additional Matters

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Terasen Inc.

May 5, 2005
Research Comment
Corporate Debt – Pipelines & Utilities

Q1/05 Results – Increased Leverage Is a Credit Concern

Sue McNamara, CFA
(416)-359-4584
sue.mcnamara@bmonb.com

Event

Terasen reported Q1/05 EPS of $0.63 (basic). After adjusting for the positive effect of a mark-to-market gain on Clean Energy's (45% - Terasen) price risk management activities recorded during the quarter, reported basic EPS were $0.60, moderately lower than our equity expectation of $0.64. For additional views, please refer to the equity research comment on Terasen Inc. by BMO Nesbitt Burns' equity analyst Karen Taylor.

Impact

Slightly negative.

Key Points

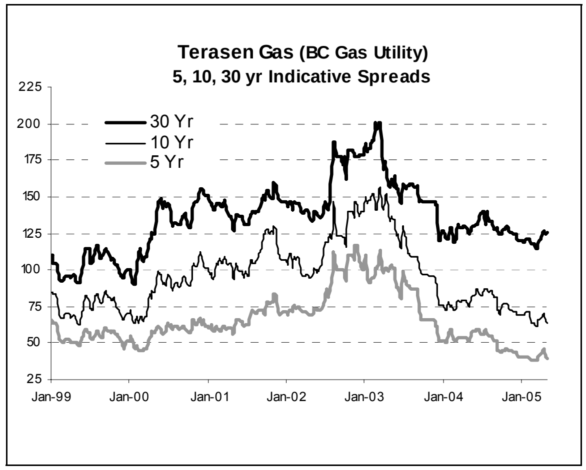
In Q1/05, Terasen Inc.'s total debt to capitalization ratio increased to 67.3% versus 64.4% at December 31, 2004 (including preferred securities as long-term debt). Our 2005 and 2006 debt to capitalization estimates are 64.74% and 64.72%, respectively, considerably higher than the averages for the pipeline and utility universe of 47.85% and 47.77%, respectively (Table 1).

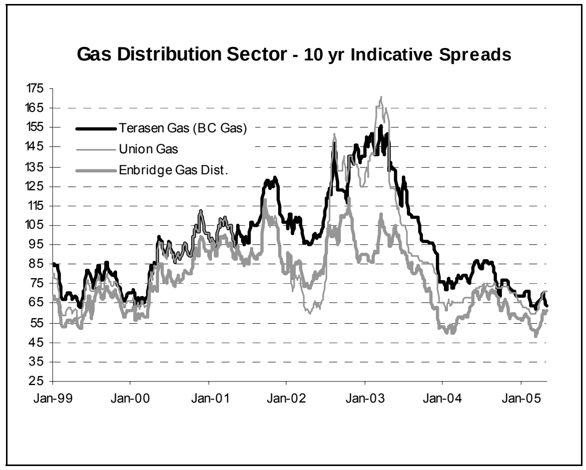
Recommendation

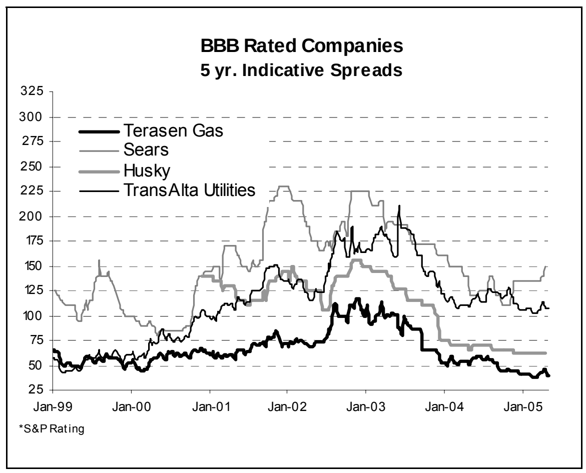
In 2005, Terasen Inc.'s 5-year and 10-year generic credit spreads tightened by 5 and 9 basis points, respectively, and the 30-year spreads have widened by 1 basis point. We believe that the company's spreads will likely widen over the next 12 months. We believe any significant spending by the company either through development projects or acquisitions (depending on how it is financed) could be a credit event, as the company is relatively thinly capitalized. We believe that a further credit risk is the expiry of the Trans Mountain system's negotiated toll settlement at the end of 2005. The company is currently in negotiations with shippers to extend or renew the toll agreement. The company's earnings and cash flow in 2006 could be negatively affected by the outcome of the negotiation.

Senior Unsecured Debt Ratings

DBRS	S&P	Moody's
A (Low)	BBB-	A3
Stable	Stable	Stable







Please refer to page 6 for Disclosure Statements, including the Analyst's Certification.

Table 1. Comparable Pipeline and Utility Capitalization Ratios

Company	2003A	2004A	2005E	2006E
Utilities - Subsidiaries				
CU Inc.	51.90%	52.32%	52.07%	51.82%
Enbridge Gas Distribution	61.28%	61.06%	55.53%	56.54%
Maritime Electric	66.26%	69.14%	79.36%	80.86%
Newfoundland Power	54.04%	53.42%	52.13%	46.52%
Nova Scotia Power	50.61%	51.32%	50.79%	49.17%
Terasen Gas	66.96%	63.60%	68.90%	69.53%
TransAlta Utilities	22.28%	72.29%	69.53%	67.06%
Union Gas	58.25%	58.34%	57.86%	57.31%
Group Average	**53.95%**	**60.19%**	**60.77%**	**59.85%**
Utilities - Holdcos/Corporates				
AltaGas	47.44%	45.55%	NA	NA
AltaLink LP	52.09%	52.30%	NA	NA
Canadian Utilities	47.66%	48.81%	46.58%	43.95%
Emera	51.93%	50.62%	51.36%	50.53%
Enersource Corporation	55.93%	56.09%	NA	NA
EPCOR Utilities	47.88%	42.26%	39.40%	37.92%
Fortis	59.03%	59.06%	57.17%	56.94%
GazMetro LP	59.86%	57.36%	54.76%	54.67%
Hydro One	48.38%	47.44%	47.39%	47.01%
Pacific Northern Gas	50.23%	49.22%	46.72%	44.42%
Toronto Hydro Corporation	56.78%	54.35%	NA	NA
TransAlta Corporation	44.85%	43.68%	43.47%	44.74%
Group Average	**51.84%**	**50.56%**	**48.36%**	**47.52%**
Pipelines - Subsidiaries				
Enbridge Pipelines	54.45%	45.89%	47.71%	45.31%
NOVA Gas Transmission	60.02%	61.96%	62.50%	63.28%
Terasen Pipelines	50.40%	43.22%	40.71%	51.84%
Group Average	**54.96%**	**50.36%**	**50.31%**	**53.48%**
Pipelines - Holdcos/Corporates				
Alliance Pipeline L.P.	68.29%	67.49%	67.58%	68.34%
Enbridge Inc.	56.23%	59.76%	57.60%	55.29%
TransCanada Corporation	58.11%	57.21%	56.11%	53.24%
Terasen Inc.	66.07%	65.16%	64.74%	64.72%
TQM Pipeline	69.75%	NA	NA	NA
Westcoast Energy	55.13%	53.25%	54.70%	54.29%
Group Average	**62.27%**	**60.57%**	**60.14%**	**59.17%**
Income Funds:				
Enbridge Income Fund	3.44%	6.71%	8.26%	7.49%
Inter Pipeline Income Fund	86.73%	28.30%	33.96%	31.80%
Pembina Pipeline Fund	16.90%	16.82%	16.73%	17.23%
Group Average	**35.69%**	**17.28%**	**19.65%**	**18.84%**

Source: BMO Nesbitt Burns' Equity Research Financial Models

Table 2. Cash Flow Statement (C$mm)

	Q1/04	Q1/05
Operating Activities:		
Net Earnings	82.2	66.3
Depreciation and Amortization	36.0	36.9
Equity Earnings	(3.9)	(3.3)
Future Income Taxes	2.3	(1.4)
Long-term Rate Stabilization Accounts	11.5	28.8
Other	2.9	0.6
	131.0	127.9
Change in Working Capital	37.2	(15.5)
Net Cash Provided by Operating Activities	**168.2**	**112.4**
Investing Activities		
Capital Expenditures	(28.9)	(83.8)
Acquisitions	-	-
Dispositions	7.6	-
Other	(6.1)	(1.6)
Cash Flow Provided by Investing Activities	**(27.4)**	**(85.4)**
Dividends:		
Capital Securities Distributions	(1.6)	-
Common Dividends	(20.3)	(23.7)
	(21.9)	**(23.7)**
Free Cash Flow	**118.9**	**3.3**
Financing Activities		
Short-term Debt	(121.4)	155.5
Long-term Debt	25.9	(40.6)
Terasen Gas Preference Shares	-	-
Capital Securities	-	-
Common Shares	7.7	4.1
Other	-	-
Change in Cash	(31.1)	(122.3)
Cash Flow Provided by Financing Activities	**(118.9)**	**(3.3)**
Cash (ST Debt), Beginning of Period	1.5	20.0
Change in Cash	31.1	122.3
Cash (ST Debt), End of Period	**32.6**	**142.3**

Source: Company Reports

Table 3. Capitalization

$mm	FY 2004	Q1/05
Bank Indebtedness	-	-
Short-term Debt	248.0	403.5
Long-term Debt	2,166.6	2,022.7
Current Maturities	416.7	516.8
Future Income Taxes/Deferred Credits	209.4	73.7
Capital Securities	125.0	125.0
Equity	1,422.1	1,418.5
Total Capitalization	**4,587.8**	**4,560.2**
%		
Bank Indebtedness	0.0%	0.0%
Short-term Debt	5.4%	8.8%
Long-term Debt	47.2%	44.4%
Current Maturities	9.1%	11.3%
Future Income Taxes	4.6%	1.6%
Capital Securities	2.7%	2.7%
Equity	31.0%	31.1%
Total Capitalization	**100.0%**	**100.0%**
Total Debt/Capitalization	**64.4%**	**67.3%**

Source: Company Reports

Terasen Inc.

Maturity Schedule

Company	Coupon	Maturity	Amount ($mm)	Instrument	Issue Date	Issue Spread	Callable	CUSIP	Outstanding ($mm)
Terasen Gas Inc.	9.800%	9-Feb-05	$40	MTNs	9-Feb-95	NA	Non-callable	05534ZAA4	$40
Terasen Gas Inc.	8.250%	29-Jun-05	$5	MTNs	29-Jun-95	NA	Non-callable	05534ZAB2	$5
Terasen Gas Inc.	6.500%	20-Jul-05	$200	MTNs	20-Jul-00	57.0 bps	Non-callable	05534ZAG1	$200
Terasen Gas Inc.	Floating[1]	26-Sep-05	$150	Floating Rate Notes	26-Sep-03	NA	Non-callable	88079ZAAZ	$150
Terasen Gas Inc.	4.850%	8-May-06	$100	MTNs	8-May-03	NA	Non-callable	88079ZAA1	$100
Terasen Gas Inc.	6.150%	31-Jul-06	$100	MTNs	30-Jul-01	73.0 bps	Make Whole + 18 bps	88079ZAL0	$100
Terasen Gas Inc.	9.750%	17-Dec-06	$20	Retractable Debentures	17-Dec-86	NA	Non-callable	NA	$20
Terasen Gas Inc.	6.500%	16-Oct-07	$100	MTNs	16-Oct-00	75.0 bps	Make Whole + 18 bps	05534ZAH9	$100
Terasen Gas Inc.	6.200%	2-Jun-08	$188	MTNs	21-Oct-97	80.0 bps	Non-callable	05534ZAC0	$188
Terasen Gas Inc.	6.300%	1-Dec-08	$200	MTNs	30-Nov-01	NA	Make Whole + 27 bps	11058ZAA8	$200
Terasen Gas Inc.	10.750%	8-Jun-09	$60	Debentures	8-Jun-89	NA	Make Whole + 40 bps	457452AH3	$60
Terasen Pipelines (Corridor)	4.240%	2-Feb-10	$150	Senior Unsecured	1-Feb-05	65.5 bps	Make Whole + 14 bps	88079VAA0	$150
Terasen Pipelines Inc.	11.500%	1-Jun-10	$35	Senior Unsecured	20-Jun-90	NA	Make Whole + 50 bps	NA	$35
Express Pipeline	6.470%	31-Dec-13	US$150	Senior Secured Notes	6-Feb-98	NA	Make Whole + 25 bps	30217VAA5	US$112.8
Terasen Inc.	5.560%	15-Sep-14	$125	MTNs	10-Sep-04	93.0 bps	Make Whole + 23 bps	88079ZAB9	$125
Terasen Pipelines (Corridor)	5.033%	2-Feb-15	$150	Senior Unsecured	1-Feb-05	81.1 bps	Make Whole + 19 bps	88079VAB8	$150
Terasen Gas Inc.	11.800%	30-Sep-15	$75	Mortgage	3-Dec-90	NA	Non-callable	05534RAA2	$75
Terasen Gas Inc.	10.300%	30-Sep-16	$200	Mortgage	21-Nov-91	104.0 bps	Make Whole + 35 bps	05534RAB0	$200
Express Pipeline	7.390%	31-Dec-19	US$250	Subordinated Secured Notes	6-Feb-98	NA	Make Whole + 50 bps	30217VAD9	US$239.2
Terasen Gas Inc.	6.950%	21-Sep-29	$150	MTNs	21-Sep-99	112.0 bps	Make Whole + 28 bps	05534ZAF3	$150
Terasen Gas Inc.	6.500%	1-May-34	$150	MTNs	29-Apr-04	127.0 bps	Make Whole + 31 bps	88078ZAB0	$150
Terasen Inc.	8.000%	19-Apr-40	$125	Subordinated Debentures	19-Apr-00	235.0 bps	Make Whole + 55 bps	05534KAA7	$125

[1] 35 basis points to 3 month Bankers Acceptances

Ownership Structure

Widely held.

Credit Facilities

Company	Facility Size	Amount Drawn Q2/04	Amount Drawn FY 2003	Letters of Credit Q2/04	Letters of Credit FY 2003	Maturity	Type
Terasen Inc.	$300	$200.0	$200.0			NA	Lines of Credit
Terasen Gas Inc.	$500	$70.0	$353.0			NA	Lines of Credit
Terasen Gas Vancouver	$213	$160.0	$160.0			NA	Lines of Credit
Corridor Pipelines	$525	$525.0	$525.0			NA	Lines of Credit

Shelf Prospectus

Company	Type	Amount	Remaining	Date	Expiry	Instruments
Terasen Gas Inc.	Shelf	$700	$550	10-Dec-03	10-Jan-05	MTNs
Terasen Inc.	Shelf	$800	$800	10-Dec-03	10-Jan-05	Unsecured Debentures

Pension Summary

	Pension Benefit Plans		Other Benefit Plans	
	FY 2004 ($mm)	FY 2003 ($mm)	FY 2004 ($mm)	FY 2003 ($mm)
Accrued Benefit Obligation	298.0	276.7	67.3	61.0
Plan Assets	274.5	255.3	-	-
Funded Status	(23.5)	(21.4)	(67.3)	(61.0)
Accrued Benefit Asset (Liability) Net of Valuation Allowance	1.5	4.1	(32.3)	(24.6)
Discount Rate	6.00%	6.25%	6.00%	6.25%
Expected Long-term Rate of of Return on Assets	7.50%	7.50%	NA	NA
Rate of Future Increase in Compensation	3.50%	3.39%	NA	NA

Historical Ratings

DBRS Rating	DBRS Trend	DBRS Date	S&P Rating	S&P Trend	S&P Date	Moody's Rating	Moody's Trend	Moody's Date
A (L)	Stable	4-Apr-00	BBB	Stable	14-Nov-01	A3	Stable	8-Nov-01
			BBB	Credit Watch Negative	19-Nov-02	A3	Under Review - Negative	19-Nov-02
			BBB-	Stable	26-Jun-03	A3	Stable	12-Dec-02

Note: On March 12, 2004, Terasen Inc. disengaged its relationship with S&P. The rating agency will continue to provide ratings on Terasen and its subsidiaries using public information.

BMO Nesbitt Burns

Company Risk Disclosure

In addition to the risks involved in investing in corporate debt securities generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Sue McNamara, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

General Disclosure

The information and opinions in this report were prepared by BMO Nesbitt Burns Inc., and BMO Nesbitt Burns Ltee/Ltd. ("BMO Nesbitt Burns"). Harris Nesbitt Corp. ("HNC") is an affiliate of BMO Nesbitt Burns. BMO Nesbitt Burns and HNC are subsidiaries of Bank of Montreal. The reader should assume that BMO Nesbitt Burns, HNC or their affiliates may have a conflict of interest and should not rely solely on this report in evaluating whether or not to buy or sell securities of issuers discussed herein.

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Company Specific Disclosure

Disclosure 2: BMO Nesbitt Burns has undertaken an underwriting liability with respect to this issuer within the past 12 months.

Disclosure 3: BMO Nesbitt Burns has provided investment banking services with respect to this issuer within the past 12 months.

Disclosure 10: This issuer is a client (or was a client) of BMO Nesbitt Burns, HNC or an affiliate within the past 12 months: Investment Banking Services.

Dissemination of Research

BMO NBI Corporate Debt Research is available via our web site http://corporate.bmo.com/research/default.asp

Additional Matters

TO U.S. RESIDENTS: HNC and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO Nesbitt Burns, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through HNC and/or BMO Nesbitt Burns Securities Ltd.

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Terasen Inc.

(TER-TSX)

Stock Rating: Underperform
Industry Rating: Market Perform

May 26, 2005
Research Comment
Pipelines

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

Investor Meetings with Management; No Change in View - Underperform

Event

On May 19 and May 20, we hosted a series of investor meetings and luncheon with Terasen Inc.'s senior management, including Randy Jesperson, President, Terasen Gas Inc., Gordon Barefoot, SVP and Chief Financial Officer, Terasen Inc. and David Bryson, Treasurer, Terasen Inc.

Impact

Neutral.

Forecasts

No change.

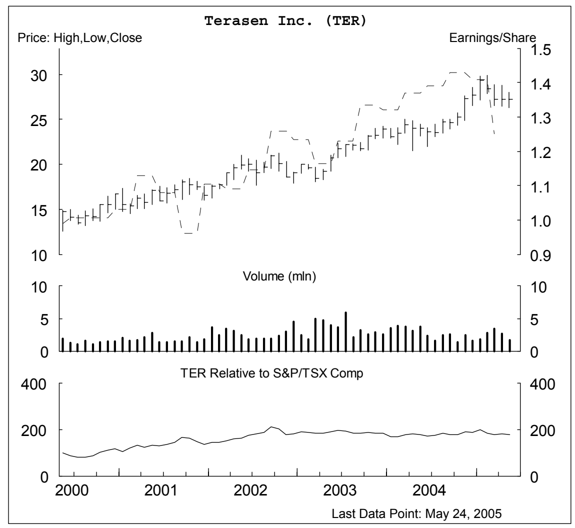
Valuation

Our target price of $27.75 reflects a weighted average valuation approach: 15x diluted 2006E EPS of $1.55 (12.5%), 1.75x 2006E book value per share of $14.34 (12.5%), and a target yield of 3.25% (75%), assuming 2006 dividends per share of $0.94.

Recommendation

We rate the shares of Terasen Underperform.

Price (24-May)	$27.25	**52-Week High**	$29.91
Target Price	$27.75	**52-Week Low**	$22.00



(FY-Dec.)	2003A	2004A	2005E	2006E
EPS	$1.28	$1.39	$1.47	$1.55
P/E			18.5x	17.6x
CFPS	$2.58	$3.27	$3.07	$3.24
P/CFPS			8.9x	8.4x
Div.	$0.77	$0.83	$0.90	$0.94
EV ($mm)	$5,296	$5,725	$6,113	$6,259
EBITDA ($mm)	$503	$521	$588	$625
EV/EBITDA	10.5x	11.0x	10.4x	10.0x

Quarterly EPS	Q1	Q2	Q3	Q4
2003A	$0.71	$0.08	-$0.07	$0.60
2004A	$0.76	$0.10	-$0.03	$0.58
2005E	$0.60a	$0.23	$0.09	$0.55

Dividend	$0.90	**Yield**	3.3%
Book Value	$13.47	**Price/Book**	2.0x
Shares O/S (mm)	105.3	**Mkt. Cap ($mm)**	$2,869
Float O/S (mm)	105.3	**Float Cap ($mm)**	$2,869
Wkly Vol (000s)	529	**Wkly $ Vol (mm)**	$13.9
Net Debt ($mm)	$3,165.7	**Next Rep. Date**	28-Jul (E)

Notes: Quarterlies reflect timing of equity issues
Major Shareholders: Widely held
First Call Mean Estimates: TERASEN INC. (C$) 2005E: $1.49; 2006E: $1.57

Please refer to pages 6 to 8 for Disclosure Statements, including the Analyst's Certification.

Details & Analysis

On May 19 and May 20, we hosted a series of investor meetings and luncheon with Terasen Inc.'s senior management, including Randy Jesperson, President, Terasen Gas Inc., Gordon Barefoot, SVP and Chief Financial Officer, Terasen Inc. and David Bryson, Treasurer, Terasen Inc. We believe that the presentation by management had the following key points:

- There has been no material change to the company's value proposition and vision since its investor day in late 2004. The company continues to target being a leading provider of energy transportation and utility infrastructure management services, characterized by operational excellence, consistent financial performance and sustained growth.
- We continue to expect that the company will remain focused on its core natural gas utility and oil pipeline operations, strive to produce reliable and consistent financial results from low risk businesses and continue to grow.
- Targeted EPS growth continues to be approximately 6% per annum, and dividend growth is expected to be sufficient to maintain an average payout ratio of approximately 60% (plus or minus 1%).
- The company continues to pursue the development of a robust list of natural gas and liquids pipeline opportunities, as set out in Table 1.

Table 1. Projects Under Development

Name	Expansion Volume	Cost (Millions)	In-Service Date	Estimated Contribution (Per Share)	Comments
Trans Mountain - Phase I	27,000 bbls/d	C$16	Mid-2004	$0.005	Increase Capacity to 225,000 from 200,000 bbls/d
Trans Mountain - Phase II	17,000 bbls/d	C$20	Early 2005	-	Dropped December 8/03
Express/Platte - Phase I & II	108,000 bbls/d	US$100	Apr-05	$0.10	Increase Capacity to 280,000 from 172,000 bbls/d
Corridor Pipeline	35,000 bbls/d	C$6.5	Fall 2005	NM	Increase Capacity to 190,000 from 155,000 bbls/d; Debottlenecking
Corridor Pipeline	110,000 bbls/d	C$7-800	2009	NA	Looping of Pipeline; Third Train Muskeg to 300,000 bbls/d
Bison Pipeline	175,000 bbls/d	C$410	Post 2010	NA	New Proposal - Combined with Corridor
Bison Pipeline - Phase I	150,000 bbls/d	C$190	Post 2010	NA	Incr Capacity to 325,000 from 172,000 bbls/d - Combined with Corridor
Bison Pipeline - Phase II	345,000 bbls/d	C$430	Post 2010	NA	Incr Capacity to 670,000 from 325,000 bbls/d - Combined with Corridor
Pump Station & Anchor TMX 1	75,000 bbls/d	C$570	Late 2008	NA	Incr Capacity to 300,000 from 225,000 bbls/d; Part I 35,000 bbls/d late '06 at cost of $205 mln; Part II 40,000 bbls/d by '08 at cost of $365 mln
Southern Leg - TMPL - Loop I	100,000 bbls/d	C$1,000	Late 2009	NA	Increase Capacity to 400,000 from 300,000 bbls/d
Southern Leg - TMPL - Loop II	450,000 bbls/d	C$1,200	Late 2010	NA	Increase Capacity to 850,000 from 400,000 bbls/d
Northern Leg - Trans Mountain	550,000 bbls/d	C$2,600	Late 2010	NA	850,000 bpd capacity; 500,000 bpd to North; 350,000 bpd to South
Eastern Leg - Trans Mountain	100,000 bbls/d	C$200	2007	NA	New Capacity from Edmonton to Hardisty on Trans Mountain
Terasen Gas Vancouver Island	NA	C$50	2007/08	$0.02	Compression on existing gas transmission line
Terasen Gas Vancouver Island	NA	C$100	2007/08	$0.06	LNG Storage Facility
Whistler Gas Pipeline	NA	C$50	2006/07	NA	Potential to replace existing propane system
Inland Pacific Connector	NA	C$3-500	2007/08	NA	Natural Gas; Terminum of Southern Crossing Pipeline to market hub at Sumas
Heartland Terminal	NA	C$30-$120	2007/10	NA	5-7 million bbls of tank and cavern storage

Source: Company Reports, BMO Nesbitt Burns

- Management updated the major projects under development, with a particular focus on natural gas distribution opportunities in Terasen Gas and Terasen Gas Vancouver Island, and liquids pipeline opportunities. The company plans to hold an Open Season process beginning in the last week of June or the first week of July to ascertain definitive shipper interest in the Pump Station & Anchor facilities of TMx1. We note that the company intends to seek expressions of interest for the current capacity of the Trans Mountain Pipe Line (approximately 225,000–250,000 bbls/d of capacity) plus the 75,000 bbls/d of capacity from the two-staged expansion (35,000 bbls/d of incremental capacity by 2006 at a cost of $205 million and a further 40,000 bbls/d at a cost of $365 million by late 2008, as highlighted above in Table 1). Open season results are likely near the end of Q3 or early Q4 2005.

- No further updates were available regarding the status of the negotiation to implement a new incentive tolling agreement on the existing Trans Mountain Pipe Line. The current ITA expires on December 31, 2005. Management indicated that discussions have not yet advanced materially, largely due to the ongoing nature of a similar negotiation for Enbridge Pipelines (100% - Enbridge Inc.). The lack of clarity with respect to this agreement is a significant concern; we do not know how the existing facility will be tolled subsequent to year-end 2005 and we are equally uncertain of the commercial arrangements regarding the planned expansion of the Trans Mountain Pipe Line. We believe that there is a material risk that 2006 EPS may be adversely affected by the outcome of this negotiation.
- We do not expect the company to issue common share equity over the forecast period. Our financial model presently reflects an assumption that equity will be required in late 2007 or early 2008, subject to the number and magnitude of projects that proceed and whether the company develops these opportunities alone or with joint venture partners.

Estimates

Our diluted 2005 and 2006 EPS estimates of $1.47 and $1.55 are unchanged. We have reviewed and updated our financial model to reflect incremental information from management's presentation. Our estimates reflect a number of projects:

- $100 million LNG storage terminal on Vancouver Island, with a proposed in-service date of late 2007.
- $50 million of compression on the Terasen Gas Vancouver Island pipeline system, with a proposed in-service date of late 2006. We note that the company does not yet have a certificate of public convenience and necessity for this project.
- Construction of $35 million of natural gas distribution facilities in Whistler, with a proposed in-service date of late 2006, and $15 million for a ground pump heating system, also for Whistler, with a proposed in-service date of mid-2007.
- Construction of the Pump Station & Anchor facilities of TMx1, as highlighted above in Table 1. We have assumed that the facilities are tolled on a conventional cost of service methodology, with a return on equity that is closer to that allowed by the National Energy Board than the return currently earned on the existing Trans Mountain oil pipeline system.
- The contribution from the water business is expected to contribute approximately 2% of the company's targeted 6% EPS growth rate over the forecast period.

- No equity issues are assumed over the forecast period (2005 and 2006).

Valuation

Our target price of $27.75 reflects a weighted average valuation approach: 15x diluted 2006E EPS of $1.55 (12.5%), 1.75x 2006E book value per share of $14.34 (12.5%), and a target yield of 3.25% (75%), assuming 2006 dividends per share of $0.94.

Recommendation

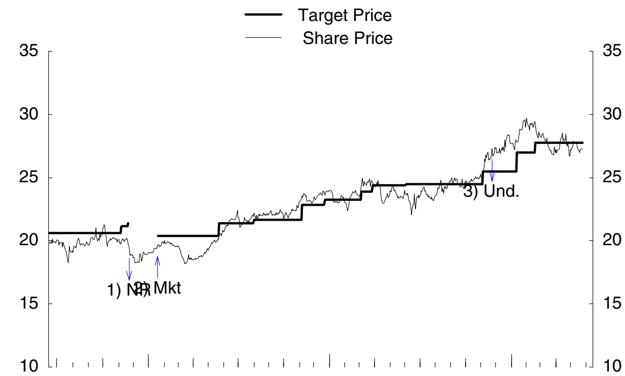
We believe that the shares are fully valued and we rate the shares Underperform.

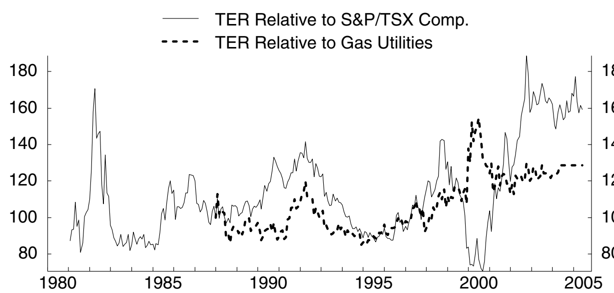
Table 2. Consolidated Summary Sheet

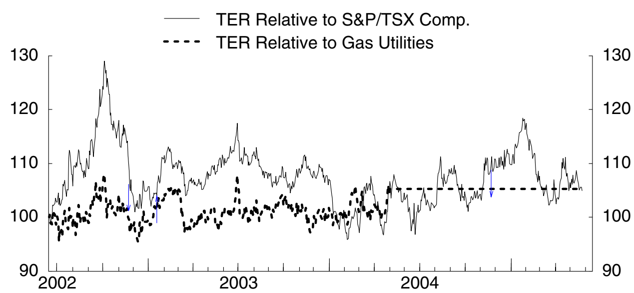
5/25/2005								Karen J. Taylor
Current Price:	$27.20							BMO Nesbitt Burns Inc.
12-Month Target Price:	$27.75							
Rate of Return:	5.33%				Recommendation:		Underperform	
	Year Ending December 31							
	1999	2000	2001	2002	2003	2004	2005E	2006E
Diluted EPS (Prior to One-Time Items)	$0.96	$0.99	$1.01	$1.26	$1.28	$1.39	$1.47	$1.55
Total EPS (Prior to One-Time Items)	$0.97	$1.00	$1.02	$1.27	$1.29	$1.40	$1.48	$1.56
Segmented EPS: Terasen Gas Utility	$0.68	$0.77	$0.89	$1.07	$0.93	$0.92	$0.94	$0.98
Trans Mountain Pipe Line	$0.26	$0.25	$0.27	$0.34	$0.54	$0.68	$0.71	$0.73
Other/**Water & Utility Services**	$0.04	($0.02)	($0.14)	($0.14)	($0.18)	$0.06	$0.12	$0.14
Corporate Activities	$0.00	$0.00	$0.00	$0.00	$0.00	($0.26)	($0.30)	($0.29)
Dividends	$0.58	$0.61	$0.65	$0.69	$0.77	$0.83	$0.90	$0.94
Payout Ratio	60.1%	61.3%	63.7%	54.5%	59.3%	59.0%	60.7%	60.1%
Average Shares (mm)	76.6	76.6	76.6	86.4	103.8	104.7	105.3	105.7
Net Book Value	$8.31	$9.02	$9.39	$12.10	$12.44	$13.04	$13.67	$14.34
Market Valuation								
Price: High	$15.50	$16.73	$18.20	$21.25	$24.00	$28.40	-	-
Price: Low	$10.50	$10.75	$14.88	$16.32	$18.18	$22.05	-	-
Price: Current	-	-	-	-	-	-	$27.20	-
P/E Ratio: High	16.0	16.24	17.84	16.73	18.60	20.30	-	-
P/E Ratio: Low	10.8	10.44	14.58	12.85	14.09	15.76	-	-
P/E Ratio: Current	-	-	-	-	-	-	18.4	17.4
Price/Book Value: High	1.92	1.85	1.94	1.76	1.93	2.18	-	-
Price/Book Value: Low	1.30	1.19	1.58	1.35	1.46	1.69	-	-
Price/Book Value: Current	-	-	-	-	-	-	1.99	1.90
Yield: High Price	3.76%	3.66%	3.57%	3.26%	3.19%	2.90%	-	-
Yield: Low Price	5.55%	5.70%	4.37%	4.24%	4.21%	3.74%	-	-
Yield: Current Price	-	-	-	-	-	-	3.31%	3.46%
Balance Sheet ($mm)								
Debt (S-T)	508.5	314.2	528.4	426.2	610.0	664.7	1,457.1	1,292.0
Debt (L-T)	1,120.9	1,561.9	1,717.1	2,123.4	2,301.1	2,166.6	1,483.7	1,841.4
Deferred Taxes/Other Deferred Items	35.0	47.3	56.8	58.1	67.5	209.4	209.4	209.4
Minority Interest	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Securities	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Shareholders' Equity	645.1	701.5	718.7	1,244.5	1,302.3	1,371.1	1,442.4	1,518.3
	2,384.5	2,749.9	3,146.0	3,977.2	4,405.9	4,536.8	4,717.6	4,986.2
Balance Sheet (%)								
Debt (S-T)	21.3%	11.4%	16.8%	10.7%	13.8%	14.7%	30.9%	25.9%
Debt (L-T)	47.0%	56.8%	54.6%	53.4%	52.2%	47.8%	31.5%	36.9%
Deferred Taxes/Other Deferred Items	1.5%	1.7%	1.8%	1.5%	1.5%	4.6%	4.4%	4.2%
Minority Interest	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred Securities	0.0%	4.5%	4.0%	3.1%	2.8%	2.8%	2.6%	2.5%
Shareholders' Equity	27.1%	25.5%	22.8%	31.3%	29.6%	30.2%	30.6%	30.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Income Statement ($mm)								
Net Profit After-Tax	82.8	80.7	77.9	109.5	133.9	146.5	156.1	165.3
Preferred Share Dividends	8.7	4.0	0.0	0.0	0.0	0.0	0.0	0.0
Earnings to Common Shareholders	74.1	76.7	77.9	109.5	133.9	146.5	156.1	165.3
Cash Flow from Operations ($mm)	117.0	173.3	53.6	311.4	267.7	342.0	324.8	345.2

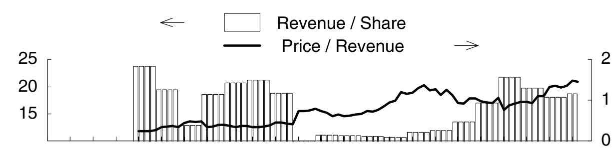
Source: BMO Nesbitt Burns

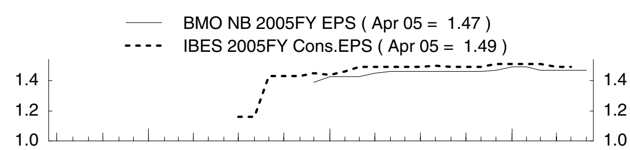
Terasen Inc. (TER)

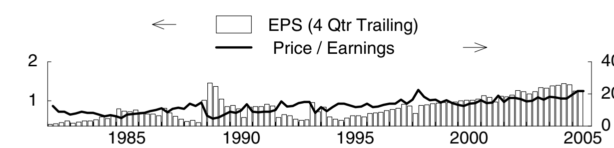


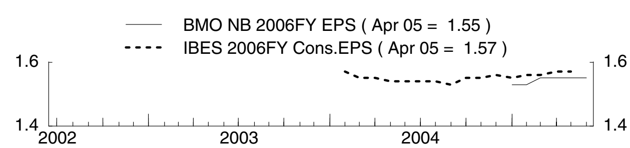












FYE (Dec.)	EPS $	P/E	DPS $	Yield %	Payout %	BV $	P/B	ROE %
1982	0.48	7	0.28	8.1	58	3.01	1.1	16
1983	0.48	8	0.28	7.0	58	3.47	1.1	15
1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
2004	1.39	20	0.84	3.0	60	13.04	2.1	11
Current*	1.25	22	0.90	3.3	72	13.47	2.0	9
Average:		13		5.0	59		1.5	13.7
Growth(%):								
5 Year:	4.8		8.8			10.5		
10 Year:	8.7		7.2			7.4		
20 Year:	2.4		5.6			6.8		

* Current EPS is the 4 Quarter Trailing to Q1/2005.

TER - Rating as of 13-Jun-02 = Mkt

	Date	Rating Change	Share Price
1	21-Nov-02	Mkt to NR	$19.76
2	17-Jan-03	NR to Mkt	$19.39
3	23-Nov-04	Mkt to Und.	$26.95

Last Daily Data Point: May 24, 2005

Company Risk Disclosure

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Analyst's Certification

I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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Sell	Underperform	16%	13%	8%

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Terasen Inc.

(TER-TSX)

Stock Rating: Underperform
Industry Rating: Market Perform

June 21, 2005
Research Comment
Pipelines

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

BC Hydro Abandons Duke Point Power Project; Underperform Rating Maintained

Event

On June 17, British Columbia Hydro and Power Authority (BC Hydro) announced that it is abandoning the proposed 252 MW Duke Point Power Project, pursuant to a decision on June 14 by the British Columbia Court of Appeal to hear an appeal of the project by a number of intervenors. BC Hydro indicated that the continuing appeal process involving this project (majority owned by Macquarie Essential Assets Partnership, together with Pristine Power Inc., and a group of private investors) increases the risk that the plant will not be built in time to meet peak load requirements on Vancouver Island in the winter of 2007/2008.

Impact

Slightly negative.

Forecasts

We have revised our financial model to reflect the consequence of this decision by BC Hydro on Terasen Gas Vancouver Island's plan to construct a $100 million LNG storage facility and add approximately $50 million of pipeline compression. Our diluted 2005 and 2006 EPS estimates decline slightly to $1.46 and $1.52, respectively, from $1.47 and $1.55 per share previously.

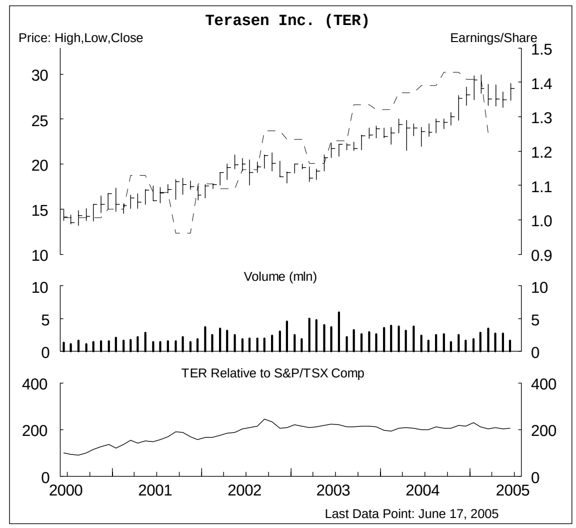
Valuation

Our target price reflects a weighted average valuation approach: 15x diluted 2006E EPS of $1.52 (12.5%), 1.75x 2006E book value of $14.31 (12.5%), and a target yield of 3.25% (75%), assuming 2006 dividends per share of $0.94.

Recommendation

We believe that the shares are fully valued at present levels and we rate them Underperform.

Price (17-Jun)	$28.40	**52-Week High**	$29.91
Target Price	$27.75	**52-Week Low**	$22.02



(FY-Dec.)	2003A	2004A	2005E	2006E
EPS	$1.28	$1.39	$1.46↓	$1.52↓
P/E			19.5x	18.7x
CFPS	$2.58	$3.27	$3.08	$3.27
P/CFPS			9.2x	8.7x
Div.	$0.77	$0.83	$0.90	$0.94
EV ($mm)	$5,296	$5,725	$6,225	$6,427
EBITDA ($mm)	$503	$521	$591	$633
EV/EBITDA	10.5x	11.0x	10.5x	10.2x

Quarterly EPS	Q1	Q2	Q3	Q4
2003A	$0.71	$0.08	-$0.07	$0.60
2004A	$0.76	$0.10	-$0.03	$0.58
2005E	$0.60a	$0.23	$0.09	$0.55

Dividend	$0.90	**Yield**	3.2%
Book Value	$13.47	**Price/Book**	2.1x
Shares O/S (mm)	105.3	**Mkt. Cap ($mm)**	$2,991
Float O/S (mm)	105.3	**Float Cap ($mm)**	$2,991
Wkly Vol (000s)	546	**Wkly $ Vol (mm)**	$14.5
Net Debt ($mm)	$3,065.8	**Next Rep. Date**	28-Jul (E)

Notes: Quarterlies reflect timing of equity issues
Major Shareholders: Widely held
First Call Mean Estimates: TERASEN INC (C$) 2005E: $1.49; 2006E: $1.57

Changes
Annual EPS
2005E $1.47 to $1.46
2006E $1.55 to $1.52

Please refer to pages 5 to 7 for Disclosure Statements, including the Analyst's Certification.

Details & Analysis

On June 17, British Columbia Hydro and Power Authority (BC Hydro) announced that it is abandoning the proposed 252 MW Duke Point Power Project, pursuant to a decision on June 14 by the British Columbia Court of Appeal to hear an appeal of the project by a number of intervenors. BC Hydro indicated that the continuing appeal process involving this project (majority owned by Macquarie Essential Assets Partnership, together with Pristine Power Inc., and a group of private investors) increases the risk that the plant will not be built in time to meet peak load requirements on Vancouver Island in the winter of 2007/2008.

The decision to abandon the Duke Point Power Project is expected to result in the following for Terasen:

- The Certificate of Public Convenience and Necessity (CPCN) issued by the British Columbia Utilities Commission (BCUC) on February 15 relating to the $100 million liquefied natural gas storage project at Mount Hayes, Vancouver Island is likely to expire, as the CPCN was conditional on a number of requirements (as set out in our comment dated February 18, 2005) that are not likely to be fulfilled. In order for the facilities to be constructed, Terasen Gas Vancouver Island (TGVI) may have to refile a facilities application with the BCUC, with a revised analysis pertaining to the economic need for the project. We believe that such an application may be filed in the fall of 2005.
- The planned in-service date of the LNG storage facility is now likely deferred at least one year. We have assumed a new in-service date of 2008 for modelling purposes versus 2007 previously.
- The planned construction of approximately $50 million of pipeline compression is now likely deferred and may not be required over the near to medium term. We have assumed for modelling purposes that the facilities are in service in 2008 versus 2007 previously.

Table 1 highlights Terasen's prospective projects under development.

Table 1. Projects Under Development

Name	Expansion Volume	Cost (Millions)	In-Service Date	Estimated Contribution (Per Share)	Comments
Trans Mountain - Phase I	27,000 bbls/d	C$16	Mid-2004	$0.005	Increase Capacity to 225,000 from 200,000 bbls/d
Trans Mountain - Phase II	17,000 bbls/d	C$20	Early 2005	-	Dropped December 8/03
Express/Platte - Phase I & II	108,000 bbls/d	US$100	Apr-05	$0.10	Increase Capacity to 280,000 from 172,000 bbls/d
Corridor Pipeline	35,000 bbls/d	C$6.5	Fall 2005	NM	Increase Capacity to 190,000 from 155,000 bbls/d; Debottlenecking
Corridor Pipeline	110,000 bbls/d	C$7-800	2009	NA	Looping of Pipeline; Third Train Muskeg to 300,000 bbls/d
Bison Pipeline	175,000 bbls/d	C$410	Post 2010	NA	New Proposal - Combined with Corridor
Bison Pipeline - Phase I	150,000 bbls/d	C$190	Post 2010	NA	Incr Capacity to 325,000 from 172,000 bbls/d - Combined with Corridor
Bison Pipeline - Phase II	345,000 bbls/d	C$430	Post 2010	NA	Incr Capacity to 670,000 from 325,000 bbls/d - Combined with Corridor
Pump Station & Anchor TMX 1	75,000 bbls/d	C$570	Late 2008	NA	Incr Capacity to 300,000 from 225,000 bbls/d; Part I 35,000 bbls/d late '06 at cost of $205 mln; Part II 40,000 bbls/d by '08 at cost of $365 mln
Southern Leg - TMPL - Loop I	100,000 bbls/d	C$1,000	Late 2009	NA	Increase Capacity to 400,000 from 300,000 bbls/d
Southern Leg - TMPL - Loop II	450,000 bbls/d	C$1,200	Late 2010	NA	Increase Capacity to 850,000 from 400,000 bbls/d
Northern Leg - Trans Mountain	550,000 bbls/d	C$2,600	Late 2010	NA	850,000 bpd capacity; 500,000 bpd to North; 350,000 bpd to South
Eastern Leg - Trans Mountain	100,000 bbls/d	C$200	2007	NA	New Capacity from Edmonton to Hardisty on Trans Mountain
Terasen Gas Vancouver Island	NA	C$50	Late 2008	$0.02	Compression on existing gas transmission line
Terasen Gas Vancouver Island	NA	C$100	Late 2008	$0.06	LNG Storage Facility
Whistler Gas Pipeline	NA	C$50	2006/07	NA	Potential to replace existing propane system
Inland Pacific Connector	NA	C$3-500	2007/08	NA	Natural Gas; Terminum of Southern Crossing Pipeline to market hub at Sumas
Heartland Terminal	NA	C$30-$120	2007/10	NA	5-7 million bbls of tank and cavern storage

Source: BMO Nesbitt Burns, Company Reports

Estimates

We have revised our financial model to reflect the consequence of this decision by BC Hydro on Terasen Gas Vancouver Island's plan to construct a $100 million LNG storage facility and add approximately $50 million of pipeline compression. Our diluted 2005 and 2006 EPS estimates decline slightly to $1.46 and $1.52, respectively, from $1.47 and $1.55 per share previously.

We assume that:

- Capital expenditures relating to the LNG storage facility are $23 million in 2006 and $38.5 million in each of 2007 and 2008, such that the in-service date of the facility is late 2008.
- Capital expenditures relating to the pipeline compression are $25 million in each of 2007 and 2008, such that the in-service date of the facilities is late 2008.

Valuation

Our target price reflects a weighted average valuation approach: 15x diluted 2006E EPS of $1.52 (12.5%), 1.75x 2006E book value of $14.31 (12.5%), and a target yield of 3.25% (75%), assuming 2006 dividends per share of $0.94.

Recommendation

We believe that the shares are fully valued at present levels and we rate them Underperform.

Table 2. Consolidated Summary Sheet

6/20/2005 — Karen J. Taylor, BMO Nesbitt Burns Inc.

Current Price: $28.75

12-Month Target Price: $27.75

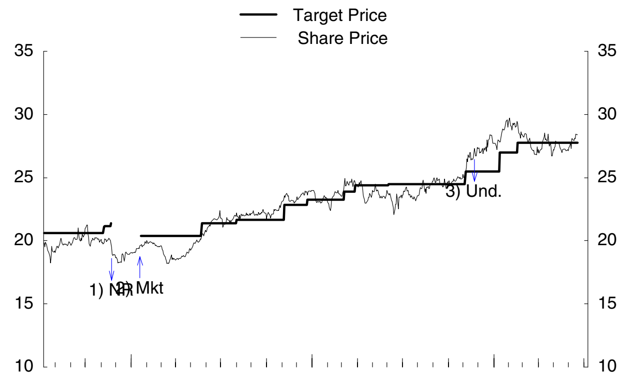
Rate of Return: -0.35%

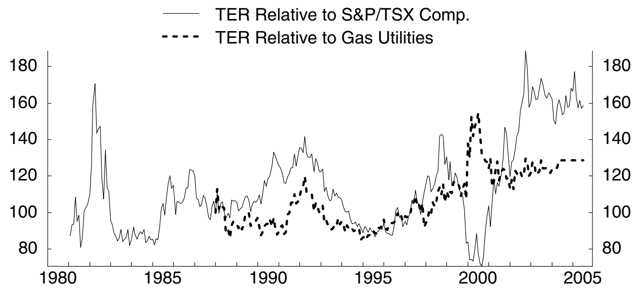
Recommendation: Underperform

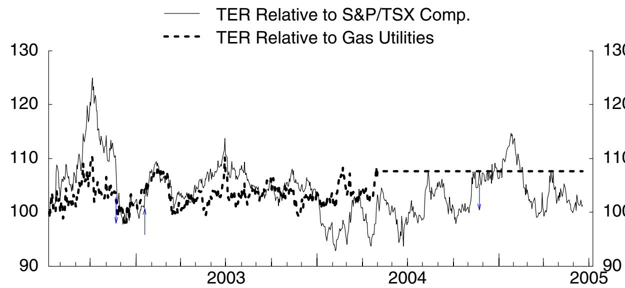
	Year Ending December 31							
	1999	**2000**	**2001**	**2002**	**2003**	**2004**	**2005E**	**2006E**
Diluted EPS (Prior to One-Time Items)	$0.96	$0.99	$1.01	$1.26	$1.28	$1.39	$1.46	$1.52
Total EPS (Prior to One-Time Items)	$0.97	$1.00	$1.02	$1.27	$1.29	$1.40	$1.47	$1.54
Segmented EPS: Terasen Gas Utility	$0.68	$0.77	$0.89	$1.07	$0.93	$0.92	$0.93	$0.96
Trans Mountain Pipe Line	$0.26	$0.25	$0.27	$0.34	$0.54	$0.68	$0.71	$0.73
Other/**Water & Utility Services**	$0.04	($0.02)	($0.14)	($0.14)	($0.18)	$0.06	$0.12	$0.14
Corporate Activities	$0.00	$0.00	$0.00	$0.00	$0.00	($0.26)	($0.30)	($0.29)
Dividends	$0.58	$0.61	$0.65	$0.69	$0.77	$0.83	$0.90	$0.94
Payout Ratio	60.1%	61.3%	63.7%	54.5%	59.3%	59.0%	61.1%	61.1%
Average Shares (mm)	76.6	76.6	76.6	86.4	103.8	104.7	105.3	105.7
Net Book Value	$8.31	$9.02	$9.39	$12.10	$12.44	$13.04	$13.66	$14.31
Market Valuation								
Price: High	$15.50	$16.73	$18.20	$21.25	$24.00	$28.40	-	-
Price: Low	$10.50	$10.75	$14.88	$16.32	$18.18	$22.05	-	-
Price: Current	-	-	-	-	-	-	$28.75	-
P/E Ratio: High	16.0	16.24	17.84	16.73	18.60	20.30	-	-
P/E Ratio: Low	10.8	10.44	14.58	12.85	14.09	15.76	-	-
P/E Ratio: Current	-	-	-	-	-	-	19.5	18.7
Price/Book Value: High	1.92	1.85	1.94	1.76	1.93	2.18	-	-
Price/Book Value: Low	1.30	1.19	1.58	1.35	1.46	1.69	-	-
Price/Book Value: Current	-	-	-	-	-	-	2.10	2.01
Yield: High Price	3.76%	3.66%	3.57%	3.26%	3.19%	2.90%	-	-
Yield: Low Price	5.55%	5.70%	4.37%	4.24%	4.21%	3.74%	-	-
Yield: Current Price	-	-	-	-	-	-	3.13%	3.27%
Balance Sheet ($mm)								
Debt (S-T)	508.5	314.2	528.4	426.2	610.0	664.7	1,410.0	1,207.0
Debt (L-T)	1,120.9	1,561.9	1,717.1	2,123.4	2,301.1	2,166.6	1,483.7	1,841.4
Deferred Taxes/Other Deferred Items	35.0	47.3	56.8	58.1	67.5	209.4	209.4	209.4
Minority Interest	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Securities	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Shareholders' Equity	645.1	701.5	718.7	1,244.5	1,302.3	1,371.1	1,441.5	1,514.8
	2,384.5	2,749.9	3,146.0	3,977.2	4,405.9	4,536.8	4,669.6	4,897.7
Balance Sheet (%)								
Debt (S-T)	21.3%	11.4%	16.8%	10.7%	13.8%	14.7%	30.2%	24.6%
Debt (L-T)	47.0%	56.8%	54.6%	53.4%	52.2%	47.8%	31.8%	37.6%
Deferred Taxes/Other Deferred Items	1.5%	1.7%	1.8%	1.5%	1.5%	4.6%	4.5%	4.3%
Minority Interest	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred Securities	0.0%	4.5%	4.0%	3.1%	2.8%	2.8%	2.7%	2.6%
Shareholders' Equity	27.1%	25.5%	22.8%	31.3%	29.6%	30.2%	30.9%	30.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Income Statement ($mm)								
Net Profit After-Tax	82.8	80.7	77.9	109.5	133.9	146.5	155.2	162.7
Preferred Share Dividends	8.7	4.0	0.0	0.0	0.0	0.0	0.0	0.0
Earnings to Common Shareholders	74.1	76.7	77.9	109.5	133.9	146.5	155.2	162.7
Cash Flow from Operations ($mm)	117.0	173.3	53.6	311.4	267.7	342.0	323.9	342.6

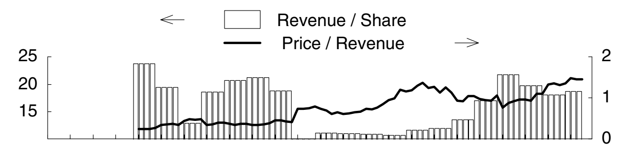
Source: BMO Nesbitt Burns

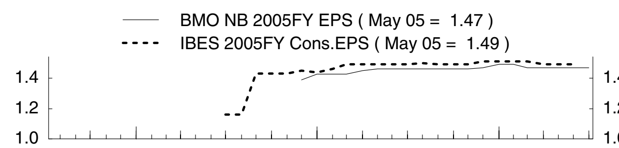
Terasen Inc. (TER)

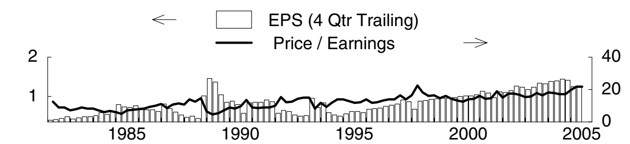


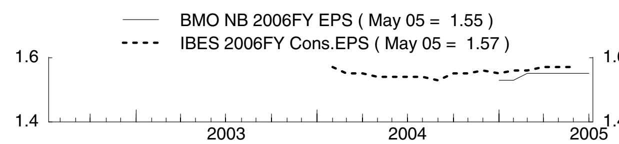












FYE (Dec.)	EPS $	P/E	DPS $	Yield %	Payout %	BV $	P/B	ROE %
1982	0.48	7	0.28	8.1	58	3.01	1.1	16
1983	0.48	8	0.28	7.0	58	3.47	1.1	15
1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
2004	1.39	20	0.84	3.0	60	13.04	2.1	11
Current*	1.25	22	0.90	3.3	72	13.47	2.0	9
Average:		13		5.0	59		1.5	13.7
Growth(%):								
5 Year:	4.8		7.7			10.5		
10 Year:	8.7		7.2			7.4		
20 Year:	2.4		5.6			6.8		

* Current EPS is the 4 Quarter Trailing to Q1/2005.

TER - Rating as of 9-Jul-02 = Mkt

	Date	Rating Change	Share Price
1	21-Nov-02	Mkt to NR	$19.76
2	17-Jan-03	NR to Mkt	$19.39
3	23-Nov-04	Mkt to Und.	$26.95

Last Daily Data Point: June 17, 2005

Company Risk Disclosure

In addition to the risks involved in investing in common stocks generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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Distribution of Ratings

Rating Category	BMO NB Rating	BMO NB Universe	BMO NB I.B. Clients*	First Call Universe**
Buy	Outperform	43%	48%	47%
Hold	Market Perform	45%	39%	46%
Sell	Underperform	12%	13%	7%

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** Reflects rating distribution of all North American equity research analysts.

BMO Nesbitt Burns

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^ Market performance as measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company.

Prior to September 1, 2003, a fourth rating tier—Top Pick—was used to designate those stocks we felt would be the best performers relative to the market. Our six Top 15 lists which guide investors to our best ideas according to six different objectives (large, small, growth, value, income and quantitative) have replaced the Top Pick rating.

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Terasen Inc

(TER-TSX)

Stock Rating: **Underperform**
Stock Price: **$29.78**
Target Price: **$28.00**

July 12, 2005
Brief Research Note
Pipelines

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

Trans Mountain Expansion Filed with NEB

Impact

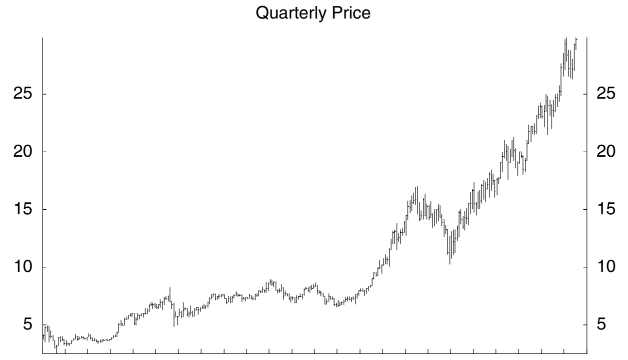
Neutral

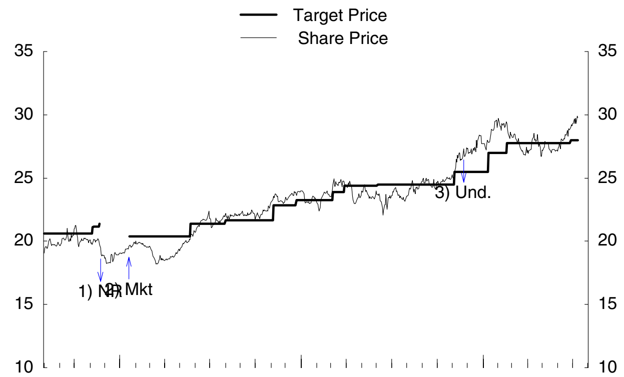
Details & Analysis

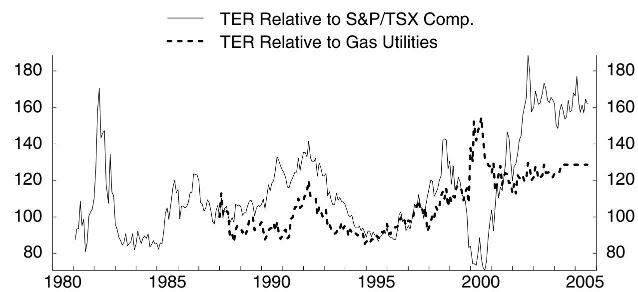
Terasen has announced that it has filed an application with the National Energy Board (NEB) to increase the capacity of the Trans Mountain pipeline system to 260,000 bbls/d from 225,000 bbls/d. The $210 million expansion includes building new and upgrading existing pump stations between Edmonton, Alberta and Burnaby, BC to meet increased demand for petroleum products in West Coast markets. The proposed expansion is projected to be available in the first quarter of 2007, subject to regulatory approval. The Trans Mountain project is fully reflected in our model. The additional facilities will now be integrated with the renegotiation of the Incentive Tolling Arrangement. Our estimates for earnings per share are unchanged. We continue to review the application.

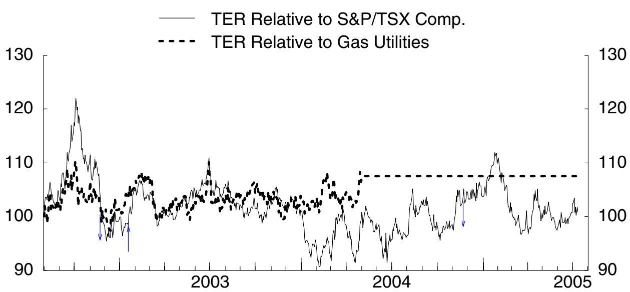
Please refer to pages 2 to 4 for Disclosure Statements, including the Analyst's Certification.

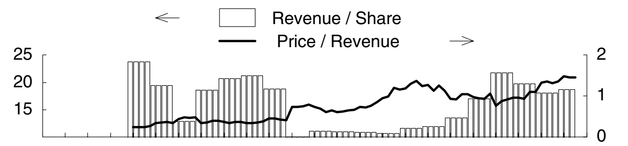
Terasen Inc. (TER)

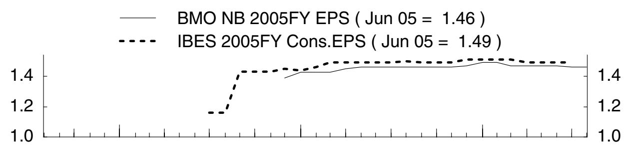


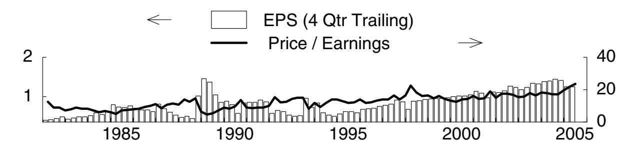


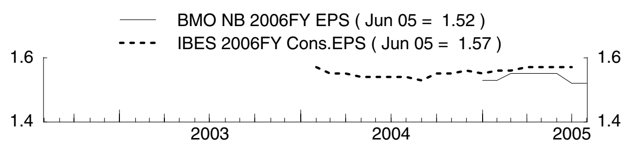












FYE (Dec.)	EPS $	P/E	DPS $	Yield %	Payout %	BV $	P/B	ROE %
1982	0.48	7	0.28	8.1	58	3.01	1.1	16
1983	0.48	8	0.28	7.0	58	3.47	1.1	15
1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
2004	1.39	20	0.84	3.0	60	13.04	2.1	11
Current*	1.25	23	0.90	3.1	72	13.47	2.2	9
Average:		13		5.0	59		1.5	13.7
Growth(%):								
5 Year:	4.5		7.7			10.5		
10 Year:	7.4		7.2			7.4		
20 Year:	2.8		5.6			6.5		

* Current EPS is the 4 Quarter Trailing to Q1/2005.

TER - Rating as of 31-Jul-02 = Mkt

	Date	Rating Change	Share Price
1	21-Nov-02	Mkt to NR	$19.76
2	17-Jan-03	NR to Mkt	$19.39
3	23-Nov-04	Mkt to Und.	$26.95

Last Daily Data Point: July 11, 2005

Company Risk Disclosure

In addition to the risks involved in investing in common stocks generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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BMO Nesbitt Burns Research

Terasen Inc.

(TER-TSX)

Stock Rating: Underperform
Industry Rating: Market Perform

July 15, 2005
Research Comment
Pipelines

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

BCUC Sets Process in Motion to Review Capital Structure and ROE – Underperform Maintained

Event

On July 11, the British Columbia Utilities Commission (BCUC) issued an Order and Notice of Procedural Conference regarding an application by Terasen Gas Inc. (100% - Terasen Inc.) and Terasen Gas (Vancouver Island) Inc. (100% - Terasen Inc.) to determine the appropriate return on equity and capital structure and to review and revise the automatic adjustment mechanism used by the BCUC to establish the allowed return on equity, annually. On July 12, Terasen Pipelines (Trans Mountain) Inc. filed an application with the National Energy Board requesting approval for the construction and operation of facilities that will comprise the Trans Mountain Pump Station Expansion Project – 35,000 bbl/d expansion of the pipeline to 260,000 bbl/d at a cost of $210 million. The planned in-service date of the project is early 2007.

Impact

Neutral.

Forecasts

Our 2005 and 2006 diluted EPS estimates are unchanged and we note: (1) we typically do not price in requested ROE and deemed equity benchmarks, due to the lack of certainty that they will be approved as filed; and (2) the Trans Mountain Pump Station Expansion Project is currently reflected in our financial model.

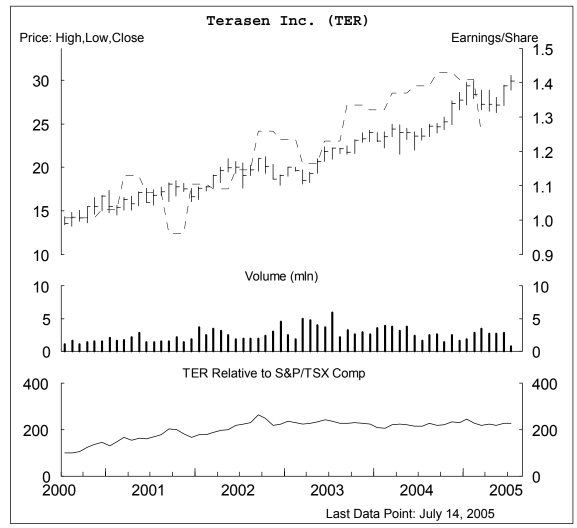
Valuation

Our target price reflects a weighted average: 17x 2006E diluted EPS of $1.52 (12.5%), 1.8x 2006E BV per share of $14.31 (12.5%) and a target yield of 3.25%, assuming 2006 dividends per share of $0.94.

Recommendation

We believe the shares are fully valued and we rate them Underperform.

Price (14-Jul)	$29.90	**52-Week High**	$30.60
Target Price	$28.00	**52-Week Low**	$23.07



(FY-Dec.)	2003A	2004A	2005E	2006E
EPS	$1.28	$1.39	$1.46	$1.52
P/E			20.5x	19.7x
CFPS	$2.58	$3.27	$3.08	$3.27
P/CFPS			9.7x	9.2x
Div.	$0.77	$0.83	$0.90	$0.94
EV ($mm)	$5,296	$5,725	$6,378	$6,543
EBITDA ($mm)	$503	$521	$588	$626
EV/EBITDA	10.5x	11.0x	10.9x	10.5x

Quarterly EPS	Q1	Q2	Q3	Q4
2003A	$0.71	$0.08	-$0.07	$0.60
2004A	$0.76	$0.10	-$0.03	$0.58
2005E	$0.60a	$0.23	$0.09	$0.55

Dividend	$0.90	**Yield**	3.0%
Book Value	$13.47	**Price/Book**	2.2x
Shares O/S (mm)	105.3	**Mkt. Cap ($mm)**	$3,148
Float O/S (mm)	105.3	**Float Cap ($mm)**	$3,148
Wkly Vol (000s)	551	**Wkly $ Vol (mm)**	$14.8
Net Debt ($mm)	$3,018.7	**Next Rep. Date**	28-Jul (E)

Notes: Quarterlies reflect timing of equity issues
Major Shareholders: Widely held
First Call Mean Estimates: TERASEN INC (C$) 2005E: $1.49; 2006E: $1.56

Please refer to pages 6 to 8 for Disclosure Statements, including the Analyst's Certification.

Details & Analysis

On July 11, the British Columbia Utilities Commission (BCUC) issued an Order and Notice of Procedural Conference regarding an application by Terasen Gas Inc. (100% - Terasen Inc.) and Terasen Gas (Vancouver Island) Inc. (100% - Terasen Inc.) to determine the appropriate return on equity and capital structure and to review and revise the automatic adjustment mechanism used by the BCUC to establish the allowed return on equity, annually.

Terasen Gas and Terasen Gas Vancouver Island filed an application with the BCUC on June 30 asserting that:

- Pursuant to the existing automatic adjustment mechanism and the prevailing long-term government of Canada bond yields, the 2006 benchmark ROE would be 7.71%. Under this scenario, Terasen is significantly discouraged from, and potentially challenged to be able to continue to invest capital in the province beyond that which is required to meet its basic obligation to serve in existing service areas.
- The need for change is established with the following six themes:

  1. The mechanism produces the lowest allowed return on equity of any regulated gas or electric utility in Canada and is out of step with other utility regulation in Canada.
  2. Good Intentions – Unintended Outcomes: when Government of Canada bond yields are below 6.00%, the sliding scale equal to 80% increases to 100% and reductions in forecast yield reduces the allowed return on equity on a one-for-one basis, fixing the equity risk premium to long-term yields at 350 basis points. This sliding scale results in a return penalty, making the formula the most punitive of those used by Canadian regulators.
  3. The Financial Times and Circumstances Have Changed: since the formula was constructed and first implemented there have been a number of changes, including the implementation of the North American Free Trade Agreement, a change in the yields of long-term Canada bonds versus the yields on long-term U.S. treasuries, and the evolution of the income trust market.
  4. A Single Test Does not Ensure the Best Outcome: regulators have all but abandoned the discounted cash flow and comparable earnings test and are relying almost exclusively on the equity risk premium test. Sole reliance on this latter test has resulted in unfairly low returns on equity for investors and may impair the financial integrity of the utilities and limit their ability to attract incremental capital on reasonable terms and conditions.
  5. Financial Flexibility to Compete: the bond rating agencies that rate the utilities' outstanding debt capital have expressed concern regarding the low allowed ROE and equity components in Canada versus those in the United States and that a credit

favourable regulatory environment is not so favourable as to justify the low returns and thin common equity capital structures typically seen in historically in Canada.

6. Risks of Terasen Gas and Terasen Gas Vancouver Island are Growing: key risks include: (i) erosion of natural gas' operating cost advantage over electricity; (ii) lower customer capture rates, resulting in substantially lower customer additions at similar housing start levels; (iii) greater penetration of multi-family dwellings in new housing starts due to lower new home affordability. Electricity has a dominant market share in the multi-family segment; (iv) a greater number of alternative energy sources are available now to prospective customers; (v) high natural gas prices have resulted in fuel switching and behavioural changes resulting in lower throughput.

7. Terasen Gas Vancouver Island: there are a number of issues specific to this utility: (i) low market penetration rate; (ii) recovery of a deficit of that reached $88 million in 2002; (iii) elimination of the Provincial royalty revenues in 2012, equal to $35 million per annum and covering 20% of the current cost of service; (iv) highly dependent on industrial load totalling more than 65% of throughput, for which approximately 2/3 is contracted on a year-to-year basis; (v) security of supply risk due to dependency on a single undersea high pressure transmission facility; and (vi) $75 million non-interest-bearing senior government debt, currently a credit to rate base.

- Terasen Gas Inc.: has requested an allowed return on equity of 10.5% for rate making purposes and deemed equity for rate purposes of 38%, versus 33% currently.

- Terasen Gas Vancouver Island: has requested an allowed return on equity of 11.25%, a 75 basis point premium to that of Terasen Gas (versus 50 basis points currently) and deemed equity of 40%, versus 35% currently.

We believe the following points are relevant regarding this application:

- The potential effective date of a revised automatic adjustment mechanism and higher deemed equity is January 1, 2006. We note that Terasen Gas' current multi-year incentive agreement expires on December 31, 2007 and the agreement governing Terasen Gas Vancouver Island expires December 31, 2005. Due to the proliferation of deferral accounts in Terasen Gas' incentive arrangements, it is unclear whether the implementation of a new return on equity and deemed equity would require a reopening of this incentive arrangement.

- If approved, the higher deemed equity would increase the utility requirement for equity by approximately $103 million at Terasen Gas and Terasen Gas Vancouver Island by approximately $24 million, for a total of $127 million. If we assume that Terasen Inc. must have, on a weighted basis, sufficient equity to fund the equity investment in its utility operations with equity, i.e., no double leverage, then Terasen Inc.'s net equity requirement is likely to increase by this amount, in addition to the equity requirement already assumed in our financial model of $125 million in 2008 to fund other growth initiatives.

- If approved, and prior to the dilution associated with an equity issue in 2006 and/or the cost of debt that would no longer be recoverable in rate base, we estimate that the contribution from Terasen Gas Inc. would increase by $0.19 per share (approximately $0.06 per share for each 100 basis point change in ROE and approximately $0.02 per share for every 100 basis point change in deemed equity), and the estimated contribution from Terasen Gas Vancouver Island would increase by approximately $0.05 per share (approximately $0.004 per share of every 100 basis point change in deemed equity and approximately $0.02 per share of every change in return on equity).

On July 12, Terasen Pipelines (Trans Mountain) Inc. filed an application with the National Energy Board requesting approval for the construction and operation of facilities that will comprise the Trans Mountain Pump Station Expansion Project – 35,000 bbl/d expansion of the pipeline to 260,000 bbl/d at a cost of $210 million. The planned in-service date of the project is early 2007. This project is fully reflected in our financial model; however,

- there is no tolling information in the application, making the estimated earnings contribution difficult to estimate; and
- the project is now anticipated to be wrapped into the renegotiation of the incentive arrangement governing the Trans Mountain Pipeline broadly. We believe the agreement may be subject to a material rebasing, due to a change in the perception of the risk profile of liquids pipeline systems since late 1999 and the likelihood that quality, reliability and system availability metrics similar to those implemented in the recently announced Enbridge liquids pipeline incentive agreement will also apply to the Trans Mountain Pipeline.

Estimates

Our 2005 and 2006 diluted EPS estimates are unchanged and we note: (1) we typically do not price in requested ROE and deemed equity benchmarks, due to the lack of certainty that they will be approved as filed; and (2) the Trans Mountain Pump Station Expansion Project is currently reflected in our financial model.

Valuation

Our target price reflects a weighted average: 17x 2006E diluted EPS of $1.52 (12.5%), 1.8x 2006E BV per share of $14.31 (12.5%) and a target yield of 3.25%, assuming 2006 dividends per share of $0.94.

Recommendation

We believe the shares of Terasen Inc. are fully valued at present levels. We rate them Underperform.

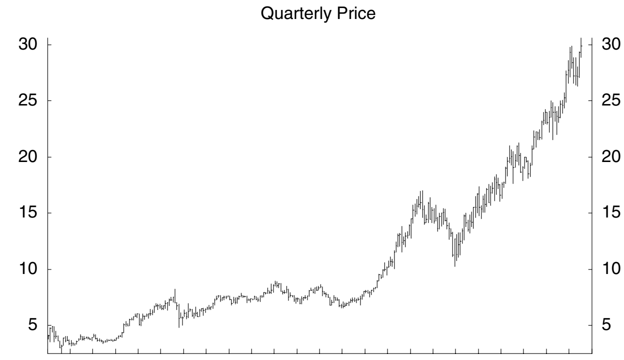
Table 1. Consolidated Summary Sheet

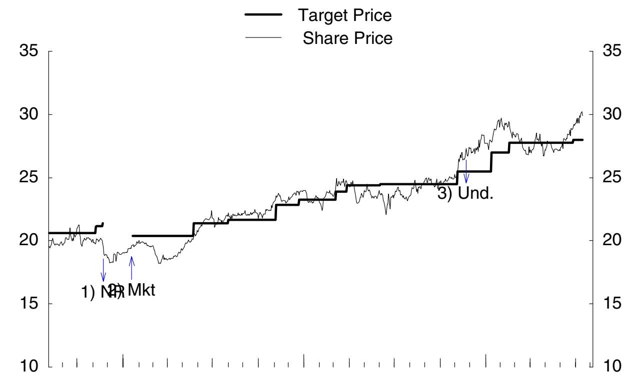
18/07/2005			Karen J. Taylor
Current Price:	$30.10		BMO Nesbitt Burns Inc.
12-Month Target Price:	$28.00		
Rate of Return:	-3.99%	Recommendation:	Underperform

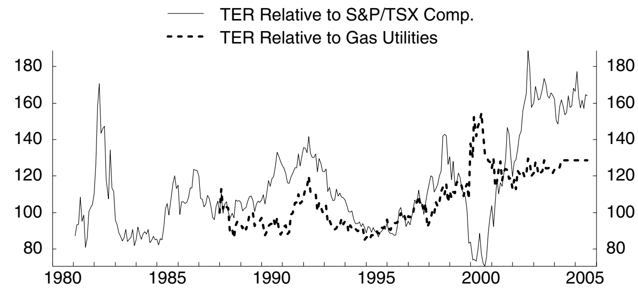
	Year Ending December 31							
	1999	**2000**	**2001**	**2002**	**2003**	**2004**	**2005E**	**2006E**
Diluted EPS (Prior to One-Time Items)	$0.96	$0.99	$1.01	$1.26	$1.28	$1.39	$1.46	$1.52
Total EPS (Prior to One-Time Items)	$0.97	$1.00	$1.02	$1.27	$1.29	$1.40	$1.47	$1.54
Segmented EPS: Terasen Gas Utility	$0.68	$0.77	$0.89	$1.07	$0.93	$0.92	$0.93	$0.96
Trans Mountain Pipe Line	$0.26	$0.25	$0.27	$0.34	$0.54	$0.68	$0.71	$0.73
Other/**Water & Utility Services**	$0.04	($0.02)	($0.14)	($0.14)	($0.18)	$0.06	$0.12	$0.14
Corporate Activities	$0.00	$0.00	$0.00	$0.00	$0.00	($0.26)	($0.30)	($0.29)
Dividends	$0.58	$0.61	$0.65	$0.69	$0.77	$0.83	$0.90	$0.94
Payout Ratio	60.1%	61.3%	63.7%	54.5%	59.3%	59.0%	61.1%	61.1%
Average Shares (mm)	76.6	76.6	76.6	86.4	103.8	104.7	105.3	105.7
Net Book Value	$8.31	$9.02	$9.39	$12.10	$12.44	$13.04	$13.66	$14.31
Market Valuation								
Price: High	$15.50	$16.73	$18.20	$21.25	$24.00	$28.40	-	-
Price: Low	$10.50	$10.75	$14.88	$16.32	$18.18	$22.05	-	-
Price: Current	-	-	-	-	-	-	$30.10	-
P/E Ratio: High	16.0	16.24	17.84	16.73	18.60	20.30	-	-
P/E Ratio: Low	10.8	10.44	14.58	12.85	14.09	15.76	-	-
P/E Ratio: Current	-	-	-	-	-	-	20.4	19.6
Price/Book Value: High	1.92	1.85	1.94	1.76	1.93	2.18	-	-
Price/Book Value: Low	1.30	1.19	1.58	1.35	1.46	1.69	-	-
Price/Book Value: Current	-	-	-	-	-	-	2.20	2.10
Yield: High Price	3.76%	3.66%	3.57%	3.26%	3.19%	2.90%	-	-
Yield: Low Price	5.55%	5.70%	4.37%	4.24%	4.21%	3.74%	-	-
Yield: Current Price	-	-	-	-	-	-	2.99%	3.12%
Balance Sheet ($mm)								
Debt (S-T)	508.5	314.2	528.4	426.2	610.0	664.7	1,410.0	1,207.0
Debt (L-T)	1,120.9	1,561.9	1,717.1	2,123.4	2,301.1	2,166.6	1,483.7	1,841.4
Deferred Taxes/Other Deferred Items	35.0	47.3	56.8	58.1	67.5	209.4	209.4	209.4
Minority Interest	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Securities	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Shareholders' Equity	645.1	701.5	718.7	1,244.5	1,302.3	1,371.1	1,441.5	1,514.8
	2,384.5	2,749.9	3,146.0	3,977.2	4,405.9	4,536.8	4,669.6	4,897.7
Balance Sheet (%)								
Debt (S-T)	21.3%	11.4%	16.8%	10.7%	13.8%	14.7%	30.2%	24.6%
Debt (L-T)	47.0%	56.8%	54.6%	53.4%	52.2%	47.8%	31.8%	37.6%
Deferred Taxes/Other Deferred Items	1.5%	1.7%	1.8%	1.5%	1.5%	4.6%	4.5%	4.3%
Minority Interest	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred Securities	0.0%	4.5%	4.0%	3.1%	2.8%	2.8%	2.7%	2.6%
Shareholders' Equity	27.1%	25.5%	22.8%	31.3%	29.6%	30.2%	30.9%	30.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Income Statement ($mm)								
Net Profit After-Tax	82.8	80.7	77.9	109.5	133.9	146.5	155.2	162.7
Preferred Share Dividends	8.7	4.0	0.0	0.0	0.0	0.0	0.0	0.0
Earnings to Common Shareholders	74.1	76.7	77.9	109.5	133.9	146.5	155.2	162.7
Cash Flow from Operations ($mm)	117.0	173.3	53.6	311.4	267.7	342.0	323.9	342.6

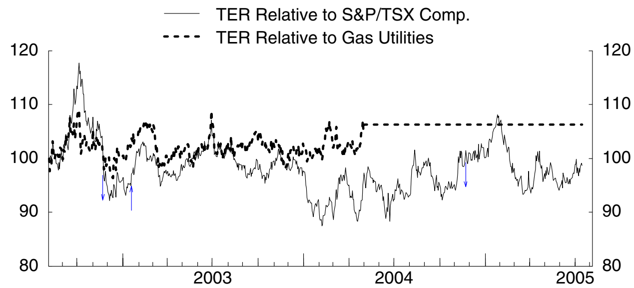
Source: BMO Nesbitt Burns

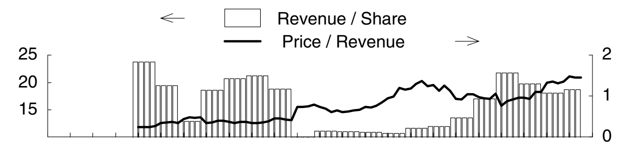
Terasen Inc. (TER)

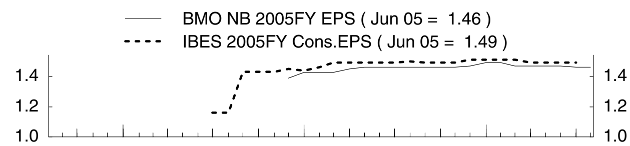


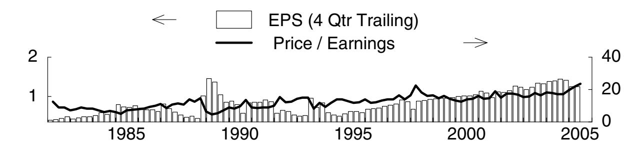


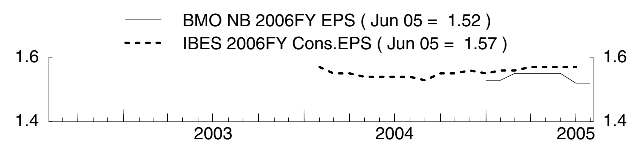












FYE (Dec.)	EPS $	P/E	DPS $	Yield %	Payout %	BV $	P/B	ROE %
1982	0.48	7	0.28	8.1	58	3.01	1.1	16
1983	0.48	8	0.28	7.0	58	3.47	1.1	15
1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
2004	1.39	20	0.84	3.0	60	13.04	2.1	11
Current*	1.25	23	0.90	3.1	72	13.47	2.2	9
Average:		13		5.0	59		1.5	13.7
Growth(%):								
5 Year:	4.5		7.7			10.5		
10 Year:	7.4		7.2			7.4		
20 Year:	2.8		5.6			6.5		

* Current EPS is the 4 Quarter Trailing to Q1/2005.

TER - Rating as of 5-Aug-02 = Mkt

	Date	Rating Change	Share Price
1	21-Nov-02	Mkt to NR	$19.76
2	17-Jan-03	NR to Mkt	$19.39
3	23-Nov-04	Mkt to Und.	$26.95

Last Daily Data Point: July 14, 2005

BMO Nesbitt Burns

Company Risk Disclosure
In addition to the risks involved in investing in common stocks generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification
I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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Disclosure 3: BMO Nesbitt Burns has provided investment banking services with respect to this issuer within the past 12 months.

Disclosure 10: This issuer is a client (or was a client) of BMO Nesbitt Burns, HNC or an affiliate within the past 12 months: Investment Banking Services.

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Rating Category	BMO NB Rating	BMO NB Universe	BMO NB I.B. Clients*	First Call Universe**
Buy	Outperform	43%	48%	47%
Hold	Market Perform	45%	39%	46%
Sell	Underperform	12%	13%	7%

* Reflects rating distribution of all companies where BMO NB has received compensation for Investment Banking services.
** Reflects rating distribution of all North American equity research analysts.

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BMO Nesbitt Burns uses the following ratings system definitions. **OP = Outperform** - Forecast to outperform the market; **Mkt = Market Perform** - Forecast to perform roughly in line with the market; **Und = Underperform** - Forecast to underperform the market; **(S) = speculative investment**; **NR = No rating at this time** - usually due to a company being in registration or coverage being initiated.

^ Market performance as measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company.

Prior to September 1, 2003, a fourth rating tier—Top Pick—was used to designate those stocks we felt would be the best performers relative to the market. Our six Top 15 lists which guide investors to our best ideas according to six different objectives (large, small, growth, value, income and quantitative) have replaced the Top Pick rating.

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Additional Matters

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BMO Nesbitt Burns Research

Terasen Inc.

(TER-TSX)

Stock Rating: **Underperform**
Industry Rating: **Market Perform**

July 29, 2005
Research Comment
Pipelines

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

Q2/05 EPS in Line with Expectations; Underperform Rating Maintained

Event

Terasen reported Q2/05 EPS of $0.28. After adjusting for: (i) $3.9 million after-tax mark-to-market gain relating to Clean Energy's (40.4% - Terasen Inc.) price risk management activities; and (ii) approximately $1.15 million of tax benefits associated with the Express Pipeline attributable to Q1/05 performance, Q2/05 EPS were $0.23, directly in line with expectations.

Impact

Neutral.

Forecasts

Our 2005 and 2006 diluted EPS estimates of $1.46 and $1.52 are unchanged. We have restated Q1/05 results, increasing the contribution to $0.62 per share from $0.60 previously, reflecting the taxation benefits reported in Q2/05 associated with Q1/05.

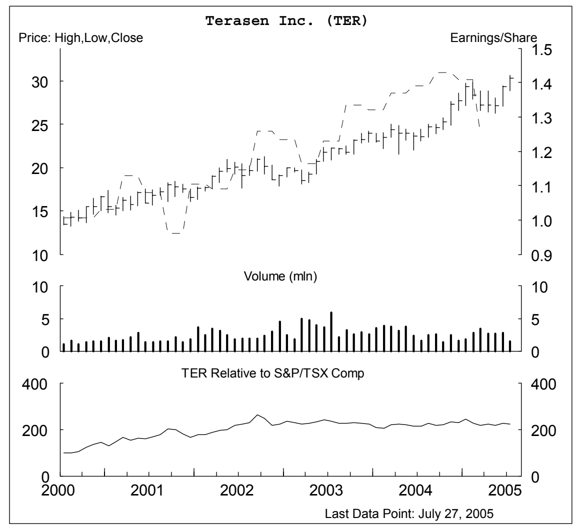
Valuation

Our target price of $28.00 reflects a weighted average valuation approach: 17x 2006E diluted EPS of $1.52 (12.5%), 1.8x 2006E book value per share of $14.31 (12.5%) and a target yield of 3.25% (75%), assuming 2006 dividends per share of $0.94.

Recommendation

We believe the shares are fully valued at present levels and we rate them Underperform.

Price (27-Jul)	$30.35	**52-Week High**	$30.69
Target Price	$28.00	**52-Week Low**	$23.10



(FY-Dec.)	**2003A**	**2004A**	**2005E**	**2006E**
EPS	$1.28	$1.39	$1.46	$1.52
P/E			20.8x	20.0x
CFPS	$2.58	$3.27	$3.08	$3.27
P/CFPS			9.8x	9.3x
Div.	$0.77	$0.83	$0.90	$0.94
EV ($mm)	$5,296	$5,725	$6,378	$6,543
EBITDA ($mm)	$503	$521	$588	$626
EV/EBITDA	10.5x	11.0x	10.9x	10.5x

Quarterly EPS	**Q1**	**Q2**	**Q3**	**Q4**
2003A	$0.71	$0.08	-$0.07	$0.60
2004A	$0.76	$0.10	-$0.03	$0.58
2005E	$0.62a	$0.23a	$0.09	$0.54↓

Dividend	$0.90	**Yield**	3.0%
Book Value	$13.53	**Price/Book**	2.2x
Shares O/S (mm)	105.5	**Mkt. Cap ($mm)**	$3,202
Float O/S (mm)	105.5	**Float Cap ($mm)**	$3,202
Wkly Vol (000s)	554	**Wkly $ Vol (mm)**	$15.0
Net Debt ($mm)	$3,018.7	**Next Rep. Date**	27-Oct (E)

Notes: Quarterlies reflect timing of equity issues
Major Shareholders: Widely held
First Call Mean Estimates: TERASEN INC (C$) 2005E: $1.49; 2006E: $1.56

Changes

Quarterly EPS
Q4/05E $0.55 to $0.54

Please refer to pages 6 to 8 for Disclosure Statements, including the Analyst's Certification.

Details & Analysis

Terasen reported Q2/05 EPS of $0.28. After adjusting for: (i) $3.9 million after-tax mark-to-market gain relating to Clean Energy's (40.4% - Terasen Inc.) price risk management activities; and (ii) approximately $1.15 million of tax benefits associated with the Express Pipeline attributable to Q1/05 performance, Q2/05 EPS were $0.23, directly in line with expectations. Quarterly performance by segment and estimated segment performance in 2005 and 2006 is set out in Table 1.

Table 1. Quarterly and Annual Performance by Segment

Contribution by Segment ($ millions)	Q1/05	Q2/05	2005E	2006E
Terasen Gas	49.0	1.6	71.8	72.2
Terasen Gas (Vancouver Island)	6.7	6.1	24.7	25.4
Trans Mountain	5.4	9.8	39.8	39.8
Corridor I	3.6	3.5	14.1	14.1
Corridor II	0.0	0.0	0.0	0.0
Express	4.9	6.5	22.9	24.9
Water	0.8	3.8	10.0	12.4
Other	(5.5)	(6.8)	(27.9)	(26.0)
Earnings Before Non-Recurring items	64.9	24.5	155.2	162.8
Average Shares	105.3	105.5	105.7	106.0
Net Earnings to Common (Basic)	$0.62	$0.23	$1.47	$1.53
Net Earnings to Common (Diluted)			$1.46	$1.52

Source: Company Reports, BMO Nesbitt Burns

We believe the following points are relevant about Q2/05 performance:

- The contribution from Terasen Gas Inc. (TGI) and Terasen Gas (Vancouver Island) was largely in line with expectations. We continue to assume that each utility earns in excess of its allowed return on equity over the forecast period. We have not yet priced in the potential reduction in allowed return resulting from the application of the current return on equity methodology and a lower interest rate outlook as per Consensus Economics. Similarly, we have not yet priced in a potential increase in allowed ROE and deemed equity as requested by both utilities in an application filed with the British Columbia Utilities Commission (BCUC) on June 30, due to the lack of certainty that the Commission will approve the application as filed.

- The contribution from the Trans Mountain Pipe Line increased in Q2/05 versus Q1/05, reflecting the resumption of full capacity utilization in Q2/05, following throughput curtailments associated with oil sands production outages and downstream refinery turnarounds. Management indicated on the conference call that there might be some throughput volatility in Q3/05, again related to oil sands production issues.

- The equity contribution from the Express Pipeline were largely in line with expectations; however, the reported tax benefits of approximately $2.3 million in Q2/05, about 50% of which were related to Q1/05, were not expected. We have fine-tuned our estimated 2005 and 2006 contribution from this pipeline to reflect taxation benefits that are expected to be recurring during the forecast period.

- The contribution from the Corridor Pipeline was lower than expected, due to a larger than expected reduction in the allowed return on equity on the pipeline pursuant to the pipeline's tolling agreement. Although our estimates reflect a National Energy Board-style reduction in allowed return, the actual decline appears to be higher than anticipated, reducing the segment contribution. We continue to believe the allowed return on this asset is lower than the company's equity cost of capital.
- The Water segment reported strong segment growth quarter over quarter and sequentially; Q2/05 performance of $3.8 million was slightly better than expected. We note that the company indicated it was actively pursuing acquisition growth opportunities in Alberta and British Columbia that could mature in the latter half of 2005 and that these acquisition opportunities are presently factored into the company's 6% per annum EPS growth target.
- Corporate expenses were generally in line with expectations and may be slightly higher in the second half of 2005. We note that the segment contribution set out in Table 1 above excludes the benefit associated with periodic mark-to-market gains recorded on Clean Power's price risk management activities. These gains are non-cash and our estimates are exclusive of these gains/losses.

Estimates

Our 2005 and 2006 diluted EPS estimates of $1.46 and $1.52 are unchanged. We have restated Q1/05 results, increasing the contribution to $0.62 per share from $0.60 previously, reflecting the taxation benefits reported in Q2/05 associated with Q1/05. As set out in Table 2, Terasen continues to have a significant number of projects under development. As we have noted previously, we have fully reflected the anticipated contribution from the following projects in our financial model (even if they extend beyond our current 2005 and 2006 forecast period):

- Pump station expansion of the Trans Mountain Pipeline that is expected to increase throughput by 35,000 bbls/d by late 2006 at a cost of $205 million.
- Anchor TMX1 expansion of the Trans Mountain Pipeline that is expected to increase throughput by 40,000 bbls/d and be in-service by late 2008 at a cost of $365 million.
- Corridor Pipeline looping and expansion project that is expected to increase capacity by approximately 1 million bbls/d and be in-service by mid-2009 at a cost of $800 million.
- $35 million Whistler Gas Pipeline project that is expected to be in-service in late 2006 and $15 million for the Whistler Ground Source Heat Pump that has a proposed in-service date of late 2007.

Table 2. Projects Under Development

Name	Expansion Volume	Cost (Millions)	In-Service Date	Estimated Contribution (Per Share)	Comments
Trans Mountain - Phase I	27,000 bbls/d	C$16	Mid-2004	$0.005	Increase Capacity to 225,000 from 200,000 bbls/d
Trans Mountain - Phase II	17,000 bbls/d	C$20	Early 2005	-	Dropped December 8/03
Express/Platte - Phase I & II	108,000 bbls/d	US$100	Apr-05	$0.10	Increase Capacity to 280,000 from 172,000 bbls/d
Corridor Pipeline	35,000 bbls/d	C$6.5	Fall 2005	NM	Increase Capacity to 190,000 from 155,000 bbls/d; Debottlenecking
Corridor Pipeline	1 million bbls/d	C$800	Mid-2009	$0.15	Looping of Pipeline; Third Train Muskeg to 300,000 bbls/d
Pump Station & Anchor TMX 1	75,000 bbls/d	C$570	Late 2008	NA	Incr Capacity to 300,000 from 225,000 bbls/d; Part I 35,000 bbls/d late '06 at cost of $205 mln; Part II 40,000 bbls/d by '08 at cost of $365 mln
Southern Leg - TMPL - Loop I	100,000 bbls/d	C$1,000	Late 2009	NA	Increase Capacity to 400,000 from 300,000 bbls/d
Southern Leg - TMPL - Loop II	450,000 bbls/d	C$1,200	Late 2010	NA	Increase Capacity to 850,000 from 400,000 bbls/d
Northern Leg - Trans Mountain	550,000 bbls/d	C$2,600	Late 2010	NA	850,000 bpd capacity; 500,000 bpd to North; 350,000 bpd to South
Eastern Leg - Trans Mountain	100,000 bbls/d	C$200	2007	NA	New Capacity from Edmonton to Hardisty on Trans Mountain
Terasen Gas Vancouver Island	NA	C$50	Late 2008	$0.02	Compression on existing gas transmission line
Terasen Gas Vancouver Island	NA	C$100	Late 2008	$0.06	LNG Storage Facility
Whistler Gas Pipeline	NA	C$50	2006/07	$0.02	Potential to replace existing propane system
Inland Pacific Connector	NA	C$3-500	2007/08	NA	Natural Gas; Terminum of Southern Crossing Pipeline to market hub at Sumas
Heartland Terminal	NA	C$30-$120	2007/10	NA	5-7 million bbls of tank and cavern storage

Source: Company Reports, BMO Nesbitt Burns

- Our estimates also reflect the July 20, 2005 application by TGVI for 2006 and 2007 rates filed with the BCUC.

We have two primary concerns relating to this stock:

- The sustainability of the contribution from the Trans Mountain Pipeline in 2006 versus 2005 given that the Incentive Tolling Agreement governing this asset expires at the end of 2005 (December 31, 2005) and must be renegotiated. While we believe that management is highly capable in this regard, we note that there has been a change in the perceived risk of the oil pipelines by shippers, interest rates have declined and quality, reliability and availability metrics are likely to be introduced to this new ITA, making above-average performance potentially more difficult.

- How much equity and when? As highlighted in the Consolidated Summary Sheet in Table 3, the company is relatively thinly capitalized. A material increase in the allowed deemed equity at TGI and TGVI and the successful execution of the company's organic greenfield and acquisition growth strategies could create the need for additional equity capital. When and how much remain to be determined.

Valuation

Our target price of $28.00 reflects a weighted average valuation approach: 17x 2006E diluted EPS of $1.52 (12.5%), 1.8x 2006E book value per share of $14.31 (12.5%) and a target yield of 3.25% (75%), assuming 2006 dividends per share of $0.94.

Recommendation

We believe the shares are fully valued at present levels and we them Underperform.

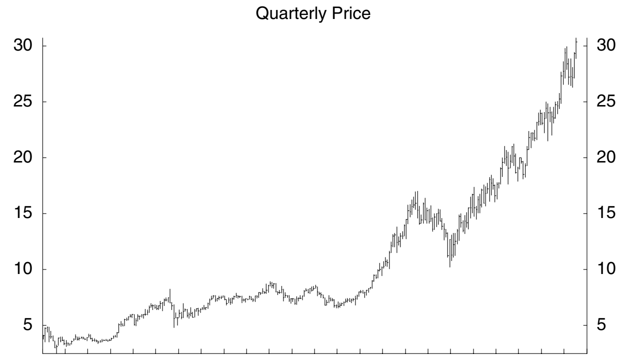
Table 3. Consolidated Summary Sheet

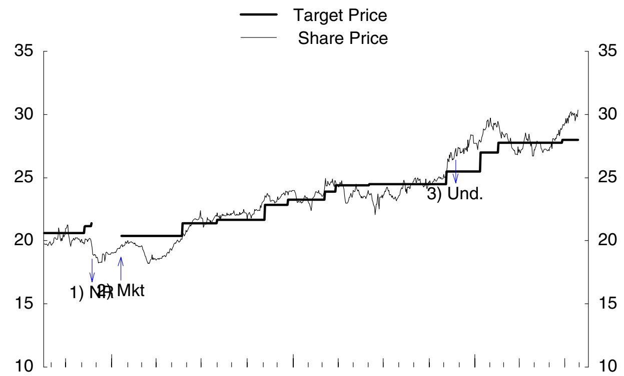
28/07/2005			Karen J. Taylor
Current Price:	$31.64		BMO Nesbitt Burns Inc.
12-Month Target Price:	$28.00		
Rate of Return:	-8.66%	Recommendation:	Underperform

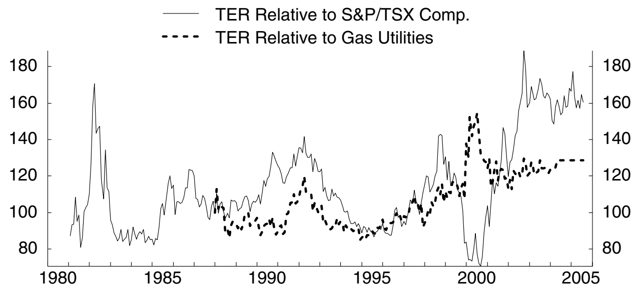
	Year Ending December 31							
	1999	2000	2001	2002	2003	2004	2005E	2006E
Diluted EPS (Prior to One-Time Items)	$0.96	$0.99	$1.01	$1.26	$1.28	$1.39	$1.46	$1.52
Total EPS (Prior to One-Time Items)	$0.97	$1.00	$1.02	$1.27	$1.29	$1.40	$1.47	$1.53
Segmented EPS: Terasen Gas Utility	$0.68	$0.77	$0.89	$1.07	$0.93	$0.92	$0.91	$0.92
Trans Mountain Pipe Line	$0.26	$0.25	$0.27	$0.34	$0.54	$0.68	$0.73	$0.74
Other/**Water & Utility Services**	$0.04	($0.02)	($0.14)	($0.14)	($0.18)	$0.06	$0.09	$0.12
Corporate Activities	$0.00	$0.00	$0.00	$0.00	$0.00	($0.26)	($0.26)	($0.25)
Dividends	$0.58	$0.61	$0.65	$0.69	$0.77	$0.83	$0.90	$0.94
Payout Ratio	60.1%	61.3%	63.7%	54.5%	59.3%	59.0%	61.3%	61.3%
Average Shares (mm)	76.6	76.6	76.6	86.4	103.8	104.7	105.7	106.0
Net Book Value	$8.31	$9.02	$9.39	$12.10	$12.44	$13.04	$13.66	$14.31
Market Valuation								
Price: High	$15.50	$16.73	$18.20	$21.25	$24.00	$28.40	-	-
Price: Low	$10.50	$10.75	$14.88	$16.32	$18.18	$22.05	-	-
Price: Current	-	-	-	-	-	-	$31.64	-
P/E Ratio: High	16.0	16.24	17.84	16.73	18.60	20.30	-	-
P/E Ratio: Low	10.8	10.44	14.58	12.85	14.09	15.76	-	-
P/E Ratio: Current	-	-	-	-	-	-	21.5	20.6
Price/Book Value: High	1.92	1.85	1.94	1.76	1.93	2.18	-	-
Price/Book Value: Low	1.30	1.19	1.58	1.35	1.46	1.69	-	-
Price/Book Value: Current	-	-	-	-	-	-	2.32	2.21
Yield: High Price	3.76%	3.66%	3.57%	3.26%	3.19%	2.90%	-	-
Yield: Low Price	5.55%	5.70%	4.37%	4.24%	4.21%	3.74%	-	-
Yield: Current Price	-	-	-	-	-	-	2.84%	2.97%
Balance Sheet ($mm)								
Debt (S-T)	508.5	314.2	528.4	426.2	610.0	664.7	1,424.6	1,228.3
Debt (L-T)	1,120.9	1,561.9	1,717.1	2,123.4	2,301.1	2,166.6	1,483.7	1,841.4
Deferred Taxes/Other Deferred Items	35.0	47.3	56.8	58.1	67.5	209.4	209.4	209.4
Minority Interest	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Securities	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Shareholders' Equity	645.1	701.5	718.7	1,244.5	1,302.3	1,371.1	1,442.2	1,516.2
	2,384.5	2,749.9	3,146.0	3,977.2	4,405.9	4,536.8	4,684.9	4,920.3
Balance Sheet (%)								
Debt (S-T)	21.3%	11.4%	16.8%	10.7%	13.8%	14.7%	30.4%	25.0%
Debt (L-T)	47.0%	56.8%	54.6%	53.4%	52.2%	47.8%	31.7%	37.4%
Deferred Taxes/Other Deferred Items	1.5%	1.7%	1.8%	1.5%	1.5%	4.6%	4.5%	4.3%
Minority Interest	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred Securities	0.0%	4.5%	4.0%	3.1%	2.8%	2.8%	2.7%	2.5%
Shareholders' Equity	27.1%	25.5%	22.8%	31.3%	29.6%	30.2%	30.8%	30.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Income Statement ($mm)								
Net Profit After-Tax	82.8	80.7	77.9	109.5	133.9	146.5	155.2	162.7
Preferred Share Dividends	8.7	4.0	0.0	0.0	0.0	0.0	0.0	0.0
Earnings to Common Shareholders	74.1	76.7	77.9	109.5	133.9	146.5	155.2	162.7
Cash Flow from Operations ($mm)	117.0	173.3	53.6	311.4	267.7	342.0	323.9	341.3

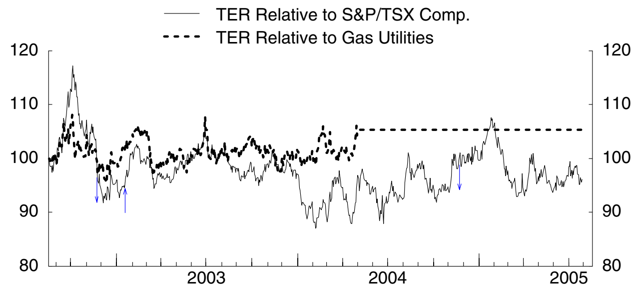
Source: BMO Nesbitt Burns

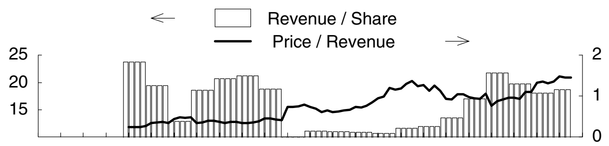
Terasen Inc. (TER)

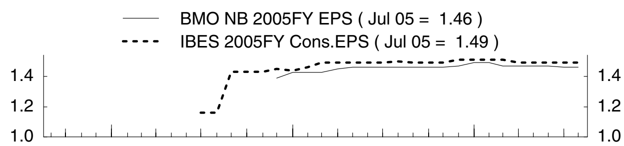


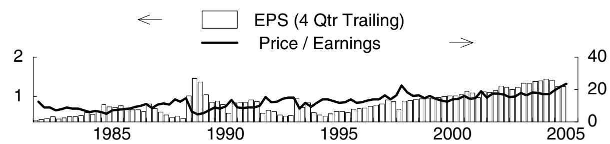


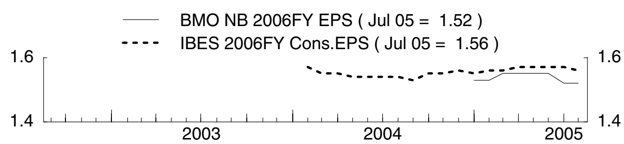












FYE (Dec.)	EPS $	P/E	DPS $	Yield %	Payout %	BV $	P/B	ROE %
1982	0.48	7	0.28	8.1	58	3.01	1.1	16
1983	0.48	8	0.28	7.0	58	3.47	1.1	15
1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
2004	1.39	20	0.84	3.0	60	13.04	2.1	11
Current*	1.25	23	0.90	3.1	72	13.47	2.2	9
Average:		13		5.0	59		1.5	13.7
Growth(%):								
5 Year:	4.5		7.7			10.5		
10 Year:	7.4		7.2			7.4		
20 Year:	2.8		5.6			6.5		

* Current EPS is the 4 Quarter Trailing to Q1/2005.

TER - Rating as of 16-Aug-02 = Mkt

	Date	Rating Change	Share Price
1	21-Nov-02	Mkt to NR	$19.76
2	17-Jan-03	NR to Mkt	$19.39
3	23-Nov-04	Mkt to Und.	$26.95

Last Daily Data Point: July 27, 2005

Company Risk Disclosure
In addition to the risks involved in investing in common stocks generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification
I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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Disclosure 2: BMO Nesbitt Burns has undertaken an underwriting liability with respect to this issuer within the past 12 months.

Disclosure 3: BMO Nesbitt Burns has provided investment banking services with respect to this issuer within the past 12 months.

Disclosure 10: This issuer is a client (or was a client) of BMO Nesbitt Burns, HNC or an affiliate within the past 12 months: Investment Banking Services.

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Rating Category	BMO NB Rating	BMO NB Universe	BMO NB I.B. Clients*	First Call Universe**
Buy	Outperform	43%	48%	47%
Hold	Market Perform	45%	39%	46%
Sell	Underperform	12%	13%	7%

* Reflects rating distribution of all companies where BMO NB has received compensation for Investment Banking services.
** Reflects rating distribution of all North American equity research analysts.

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^ Market performance as measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company.

Prior to September 1, 2003, a fourth rating tier—Top Pick—was used to designate those stocks we felt would be the best performers relative to the market. Our six Top 15 lists which guide investors to our best ideas according to six different objectives (large, small, growth, value, income and quantitative) have replaced the Top Pick rating.

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Additional Matters

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Terasen Inc.

Q2/05 Results – Leverage Concern Remains

July 29, 2005
Research Comment
Corporate Debt – Pipelines & Utilities

Sue McNamara, CFA
(416)-359-4584
sue.mcnamara@bmonb.com

Event

Terasen reported Q2/05 EPS of $0.23 (after one-time adjustments), in line with our equity expectation.

Impact

Neutral.

Key Points

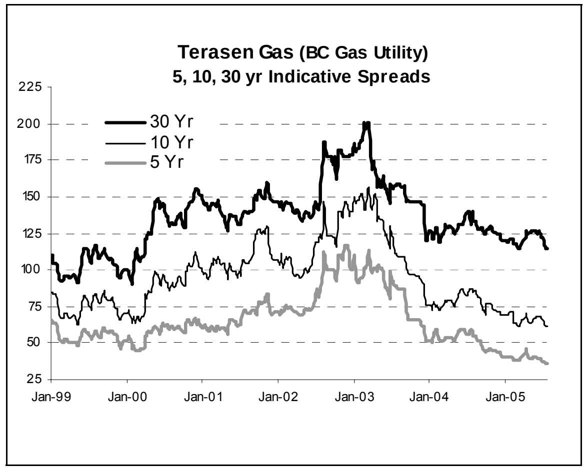
At June 30, 2005, the company's debt to total capital ratio was 64.6% versus 61.7% at year-end. If we assume that the company's available cash will be used to repay a portion of short-term debt, the company's ratio at quarter-end would decrease to 63.9%. We continue to believe that Terasen's leverage is higher than its peer group of comparable utilities. Although somewhat supported by the company's regulatory framework, we believe that the relatively high leverage could be a credit negative as the company pursues its robust list of development projects or undertakes a large scale acquisition.

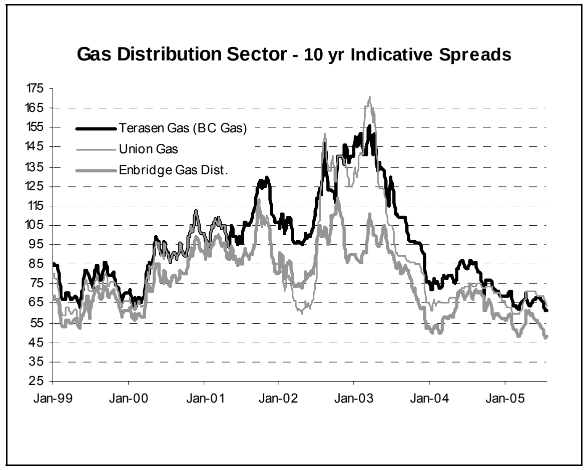
Recommendation

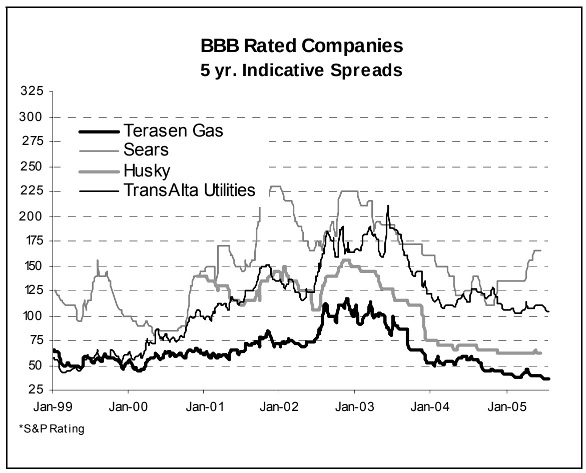
In 2005, Terasen Inc.'s 5-year, 10-year and 30-year generic credit spreads tightened by 8, 12 and 10 basis points, respectively. We believe that the company's spreads will likely widen over the next 12 months. We believe any significant spending by the company either through development projects or acquisitions (depending on how it is financed) could be a credit event, as the company is relatively thinly capitalized. We believe that a further credit risk is the expiry of the Trans Mountain system's negotiated toll settlement at the end of 2005. The company is currently in negotiations with shippers to extend or renew the toll agreement. The company's earnings and cash flow in 2006 could be negatively affected by the outcome of the negotiation. We also believe that regulatory risk at Terasen Gas is likely rising.

Senior Unsecured Debt Ratings

DBRS	S&P	Moody's
A (Low)	BBB-	A3
Stable	Stable	Stable







Q2/05 Results

Terasen reported Q2/05 EPS of $0.28. Q2/05 EPS were $0.23, directly in line with our equity expectation, after adjusting for: (i) a $3.9 million after-tax mark-to-market gain relating to Clean Energy's (40.4% - Terasen) price risk management activities; and (ii) approximately $1.15 million of tax benefits associated with the Express Pipeline attributable to Q1/05. For additional views, please refer to the equity research comment on Terasen Inc. by BMO Nesbitt Burns' equity analyst Karen Taylor.

Cash Flow

Terasen reported free cash of -$2.8 million during the quarter versus $25.4 million in Q2/04. The variance is largely attributable to an increase in capital expenditures ($43.1 million in Q2/05 versus $31.8 million in Q2/04) and a change in the working capital requirements contribution to operating cash flow ($9.8 million in Q2/05 versus $32.8 million in Q2/04). The free cash flow deficiency was funded with a draw on available cash.

Capital Resources

During the quarter, the company repaid $43 million and $6.4 million of short-term and long-term debt, respectively, from available cash. At quarter end, Terasen had $91.6 million of available cash remaining. Terasen Inc. has no debt maturities in 2005 and 2006, whereas Terasen Gas (100% - Terasen Inc.) has debt maturities of $350 million in 2005 and $220 million in 2006. We believe that the maturities will likely be refinanced or repaid with short-term debt issuance. At quarter-end, the company and its subsidiaries had $743 million available under its total lines of credit of $1.4 billion. At June 30, 2005, the company's debt to total capital ratio was 64.6% versus 61.7% at year-end. If we assume that the company's available cash will be used to repay a portion of short-term debt, the company's ratio at quarter-end would decrease to 63.9%. We continue to believe that Terasen's leverage is higher than its peer group of comparable utilities. Although somewhat supported by the company's regulatory framework, we believe that the relatively high leverage could be a credit negative as the company pursues its robust list of development projects or undertakes a large scale acquisition.

Table 1. Capitalization

	2004	Q2/05
$mm		
Bank Indebtedness	-	-
Short-term Debt	248.0	360.5
Long-term Debt	2,166.6	2,029.1
Current Maturities	416.7	628.9
Future Income Taxes/Deferred Credits	209.4	102.7
Capital Securities	125.0	125.0
Equity	1,422.1	1,427.5
Total Capitalization	**4,587.8**	**4,673.7**
Capitalization (%)		
Bank Indebtedness	0.0%	0.0%
Short-term Debt	5.4%	7.7%
Long-term Debt	47.2%	43.4%
Current Maturities	9.1%	13.5%
Future Income Taxes	4.6%	2.2%
Capital Securities	2.7%	2.7%
Equity	31.0%	30.5%
Total Capitalization	**100.0%**	**100.0%**
Debt/Total Capital	**61.7%**	**64.6%**

Source: Company Reports

Credit Ratings

Terasen Inc.'s senior unsecured debt is rated A(Low), BBB- and A3 by DBRS, S&P and Moody's, respectively. The outlook from all three rating agencies is Stable. S&P provides ratings coverage of the Terasen companies, based on publicly available information.

In its latest summary report on Terasen Inc., (June 3, 2005) S&P stated that the company's below average financial risk profile reflects the company's existing gas regulatory framework and is somewhat offset by the pipelines' negotiated shipper contracts. S&P expects that any acquisition or major development project will have risk profiles consistent with the regulated, energy infrastructure-type assets and will be financed in line with the company's current capital structure.

DBRS believes that the medium-term outlook for Terasen remains relatively stable given the increased asset diversification providing to earnings and operating cash flows. DBRS notes that the key risks to Terasen's credit ratings are related to the outcome of the large-scale projects currently under development. DBRS states that as the importance of Terasen's pipelines and non-regulated businesses continues to grow, the company will require a higher equity base to maintain its current ratings.

Moody's rates Terasen Inc. one notch below that senior unsecured rating of Terasen Gas, at A2. The one-notch differential reflects the structural subordination of Terasen's debt to operating subsidiary debt at Terasen Gas, Terasen Gas Vancouver Island, Corridor, Trans Mountain and Express as well as the lack of ring fencing or other restrictions that could limit Terasen Gas' ability to make dividend payments to Terasen Inc. Moody's expects that Terasen will take a prudent approach to the scale and financing of investments in the petroleum pipeline segment.

Recommendation

In 2005, Terasen Inc.'s 5-year, 10-year and 30-year generic credit spreads tightened by 8, 12 and 10 basis points, respectively. We note that Terasen Inc.'s credit spreads likely reflect a scarcity premium, as the holding company has only two maturities outstanding totalling $300 million. We believe that the company's spreads will likely widen over the next 12 months. We believe any significant spending by the company either through development projects or acquisitions (depending on how it is financed) could be a credit event, as the company is relatively thinly capitalized. We believe that a further credit risk is the expiry of the Trans Mountain system's negotiated toll settlement at the end of 2005. The company is currently in negotiations with shippers to extend or renew the toll agreement. The company's earnings and cash flow in 2006 could be negatively affected by the outcome of the negotiation. We also believe that regulatory risk at Terasen Gas is likely rising. On July 11, the British Columbia Utilities Commission (BCUC) issued an Order and Notice of Procedural Conference regarding an application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. to determine the appropriate return on equity and capital structure, and to review and revise the automatic adjustment mechanism used by the BCUC to establish the allowed return on equity annually (please see Karen Taylor's equity comment on Terasen Inc. dated July 15, 2005 for more details).

Table 3. Cash Flow Statement (C$mm)

	Q2/04	Q2/05
Operating Activities:		
Net Earnings	12.3	29.5
Depreciation and Amortization	37.8	36.3
Equity Earnings	(3.2)	(9.3)
Future Income Taxes	(0.2)	1.7
Long-term Rate Stabilization Accounts	2.2	(5.3)
Other	2.0	2.6
	50.9	55.5
Change in Working Capital	32.8	9.8
Net Cash Provided by Operating Activities	**83.7**	**65.3**
Investing Activities		
Capital Expenditures	(31.8)	(43.1)
Acquisitions	-	-
Dispositions	-	-
Other	(2.7)	(1.3)
Cash Flow Provided by Investing Activities	**(34.5)**	**(44.4)**
Dividends:		
Capital Securities Distributions	(1.7)	-
Common Dividends	(22.1)	(23.7)
	(23.8)	**(23.7)**
Free Cash Flow	**25.4**	**(2.8)**
Financing Activities		
Short-term Debt	(181.5)	(43.0)
Long-term Debt	139.6	(6.4)
Terasen Gas Preference Shares	-	-
Capital Securities	-	-
Common Shares	1.2	1.5
Other	-	-
Change in Cash	15.3	50.7
Cash Flow Provided by Financing Activities	**(25.4)**	**2.8**
Cash (ST Debt), Beginning of Period	32.6	142.3
Change in Cash	(15.3)	(50.7)
Cash (ST Debt), End of Period	**17.3**	**91.6**

Source: Company Reports

Terasen Inc.

Maturity Schedule

Company	Coupon	Maturity	Amount ($mm)	Instrument	Issue Date	Issue Spread	Callable	CUSIP	Outstanding ($mm)
Terasen Gas Inc.	9.800%	9-Feb-05	$40	MTNs	9-Feb-95	NA	Non-callable	05534ZAA4	$40
Terasen Gas Inc.	8.250%	29-Jun-05	$5	MTNs	29-Jun-95	NA	Non-callable	05534ZAB2	$5
Terasen Gas Inc.	6.500%	20-Jul-05	$200	MTNs	20-Jul-00	57.0 bps	Non-callable	05534ZAG1	$200
Terasen Gas Inc.	Floating[1]	26-Sep-05	$150	Floating Rate Notes	26-Sep-03	NA	Non-callable	88079ZAAZ	$150
Terasen Gas Inc.	4.850%	8-May-06	$100	MTNs	8-May-03	NA	Non-callable	88079ZAA1	$100
Terasen Gas Inc.	6.150%	31-Jul-06	$100	MTNs	30-Jul-01	73.0 bps	Make Whole + 18 bps	88079ZAL0	$100
Terasen Gas Inc.	9.750%	17-Dec-06	$20	Retractable Debentures	17-Dec-86	NA	Non-callable	NA	$20
Terasen Gas Inc.	6.500%	16-Oct-07	$100	MTNs	16-Oct-00	75.0 bps	Make Whole + 18 bps	05534ZAH9	$100
Terasen Gas Inc.	6.200%	2-Jun-08	$188	MTNs	21-Oct-97	80.0 bps	Non-callable	05534ZAC0	$188
Terasen Gas Inc.	6.300%	1-Dec-08	$200	MTNs	30-Nov-01	NA	Make Whole + 27 bps	11058ZAA8	$200
Terasen Gas Inc.	10.750%	8-Jun-09	$60	Debentures	8-Jun-89	NA	Make Whole + 40 bps	457452AH3	$60
Terasen Pipelines (Corridor)	4.240%	2-Feb-10	$150	Senior Unsecured	1-Feb-05	65.5 bps	Make Whole + 14 bps	88079VAA0	$150
Terasen Pipelines Inc.	11.500%	1-Jun-10	$35	Senior Unsecured	20-Jun-90	NA	Make Whole + 50 bps	NA	$35
Express Pipeline	6.470%	31-Dec-13	US$150	Senior Secured Notes	6-Feb-98	NA	Make Whole + 25 bps	30217VAA5	US$112.8
Terasen Inc.	5.560%	15-Sep-14	$125	MTNs	10-Sep-04	93.0 bps	Make Whole + 23 bps	88079ZAB9	$125
Terasen Pipelines (Corridor)	5.033%	2-Feb-15	$150	Senior Unsecured	1-Feb-05	81.1 bps	Make Whole + 19 bps	88079VAB8	$150
Terasen Gas Inc.	11.800%	30-Sep-15	$75	Mortgage	3-Dec-90	NA	Non-callable	05534RAA2	$75
Terasen Gas Inc.	10.300%	30-Sep-16	$200	Mortgage	21-Nov-91	104.0 bps	Make Whole + 35 bps	05534RAB0	$200
Express Pipeline	7.390%	31-Dec-19	US$250	Subordinated Secured Notes	6-Feb-98	NA	Make Whole + 50 bps	30217VAD9	US$239.2
Terasen Gas Inc.	6.950%	21-Sep-29	$150	MTNs	21-Sep-99	112.0 bps	Make Whole + 28 bps	05534ZAF3	$150
Terasen Gas Inc.	6.500%	1-May-34	$150	MTNs	29-Apr-04	127.0 bps	Make Whole + 31 bps	88078ZAB0	$150
Terasen Inc.	8.000%	19-Apr-40	$125	Subordinated Debentures	19-Apr-00	235.0 bps	Make Whole + 55 bps	05534KAA7	$125

[1] 35 basis points to 3 month Bankers Acceptances

Ownership Structure

Widely held.

Credit Facilities

Company	Facility Size	Amount Drawn Q2/04	Amount Drawn FY 2003	Letters of Credit Q2/04	Letters of Credit FY 2003	Maturity	Type
Terasen Inc.	$300	$200.0	$200.0			NA	Lines of Credit
Terasen Gas Inc.	$500	$70.0	$353.0			NA	Lines of Credit
Terasen Gas Vancouver	$213	$160.0	$160.0			NA	Lines of Credit
Corridor Pipelines	$525	$525.0	$525.0			NA	Lines of Credit

Shelf Prospectus

Company	Type	Amount	Remaining	Date	Expiry	Instruments
Terasen Gas Inc.	Shelf	$700	$550	10-Dec-03	10-Jan-05	MTNs
Terasen Inc.	Shelf	$800	$800	10-Dec-03	10-Jan-05	Unsecured Debentures

Pension Summary

	Pension Benefit Plans FY 2004 ($mm)	Pension Benefit Plans FY 2003 ($mm)	Other Benefit Plans FY 2004 ($mm)	Other Benefit Plans FY 2003 ($mm)
Accrued Benefit Obligation	298.0	276.7	67.3	61.0
Plan Assets	274.5	255.3	-	-
Funded Status	(23.5)	(21.4)	(67.3)	(61.0)
Accrued Benefit Asset (Liability) Net of Valuation Allowance	1.5	4.1	(32.3)	(24.6)
Discount Rate	6.00%	6.25%	6.00%	6.25%
Expected Long-term Rate of of Return on Assets	7.50%	7.50%	NA	NA
Rate of Future Increase in Compensation	3.50%	3.39%	NA	NA

Historical Ratings

DBRS Rating	DBRS Trend	DBRS Date	S&P Rating	S&P Trend	S&P Date	Moody's Rating	Moody's Trend	Moody's Date
A (L)	Stable	4-Apr-00	BBB	Stable	14-Nov-01	A3	Stable	8-Nov-01
			BBB	Credit Watch Negative	19-Nov-02	A3	Under Review - Negative	19-Nov-02
			BBB-	Stable	26-Jun-03	A3	Stable	12-Dec-02

Note: On March 12, 2004, Terasen Inc. disengaged its relationship with S&P. The rating agency will continue to provide ratings on Terasen and its subsidiaries using public information.

Company Risk Disclosure

In addition to the risks involved in investing in corporate debt securities generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Sue McNamara, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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Company Specific Disclosure

Disclosure 2: BMO Nesbitt Burns has undertaken an underwriting liability with respect to this issuer within the past 12 months.

Disclosure 3: BMO Nesbitt Burns has provided investment banking services with respect to this issuer within the past 12 months.

Disclosure 10: This issuer is a client (or was a client) of BMO Nesbitt Burns, HNC or an affiliate within the past 12 months: Investment Banking Services.

Dissemination of Research

BMO NBI Corporate Debt Research is available via our web site http://corporate.bmo.com/research/default.asp

Additional Matters

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Terasen Inc.

(TER-TSX)

August 2, 2005
Research Comment
Pipelines

Stock Rating: Market Perform ↑
Industry Rating: Market Perform

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

Kinder Morgan Agrees to Acquire Company; Rating Raised to Market Perform

Event

Terasen and Kinder Morgan have jointly announced that Kinder Morgan has agreed to acquire all of the outstanding shares of Terasen Inc. for $35.91 per share. The total enterprise value of the transaction is approximately C$6.9 billion. The key details of the transaction are set out herein. We estimate that the transaction is priced at 24.6x estimated diluted 2005 EPS of $1.46, 2.62 x estimated 2005 book value per share of $13.66 and 11x EV/EBITDA. We believe the transaction is priced at the upper end of the relevant range.

Impact

Positive. We have increased our target price to $35.95 from $28.00 to reflect the proposed transaction. The proposed transaction effectively mitigates our concerns relating to this stock: (1) the potential adverse effect on EPS relating to the expiry of the Trans Mountain Incentive Tolling Agreement on December 31, 2005; (2) and the likelihood that the company would require significant equity financing in order to fund its development program and potentially higher deemed equity in its natural gas distribution segment.

Forecasts

Unchanged.

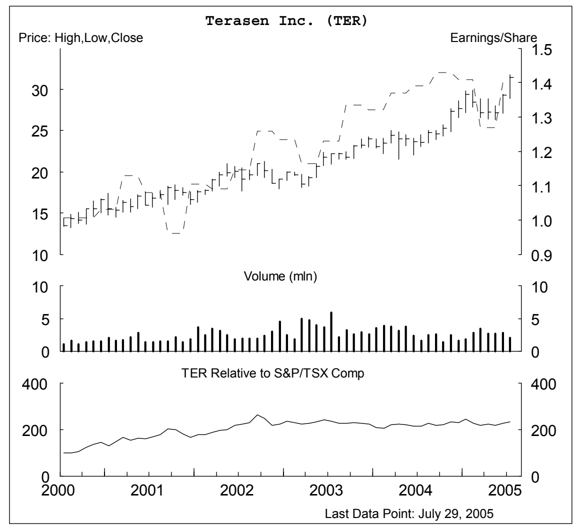
Valuation

Our revised target price of $35.95 is 23.6x 2006E diluted EPS of $1.52 (12.5%), 2.51 x estimated 2006 book value per share of $14.31 (12.5%) and a yield of 2.62% (75%), assuming 2006 dividends per share of $0.94. We believe the offer price is reasonable and we recommend that shareholders endorse it.

Recommendation

We believe the shares are reasonably valued and we rate them Market Perform.

Price (29-Jul)	$31.40	**52-Week High**	$31.78
Target Price	$35.95↑	**52-Week Low**	$23.38



(FY-Dec.)	2003A	2004A	2005E	2006E
EPS	$1.28	$1.39	$1.46	$1.52
P/E			21.5x	20.7x
CFPS	$2.58	$3.27	$3.08	$3.27
P/CFPS			10.2x	9.6x
Div.	$0.77	$0.83	$0.90	$0.94
EV ($mm)	$5,296	$5,725	$6,378	$6,543
EBITDA ($mm)	$503	$521	$588	$626
EV/EBITDA	10.5x	11.0x	10.9x	10.5x

Quarterly EPS	Q1	Q2	Q3	Q4
2003A	$0.71	$0.08	-$0.07	$0.60
2004A	$0.76	$0.10	-$0.03	$0.58
2005E	$0.62a	$0.23a	$0.09	$0.54

Dividend	$0.90	**Yield**	2.9%
Book Value	$13.53	**Price/Book**	2.3x
Shares O/S (mm)	105.5	**Mkt. Cap ($mm)**	$3,313
Float O/S (mm)	105.5	**Float Cap ($mm)**	$3,313
Wkly Vol (000s)	558	**Wkly $ Vol (mm)**	$15.2
Net Debt ($mm)	$3,018.7	**Next Rep. Date**	27-Oct (E)

Notes: Quarterlies reflect timing of equity issues
Major Shareholders: Widely held
First Call Mean Estimates: TERASEN INC (C$) 2005E: $1.49; 2006E: $1.56

Changes

Target
$28.00 to $35.95
Rating
Und to Mkt

Details & Analysis

Terasen and Kinder Morgan have jointly announced that Kinder Morgan has agreed to acquire all of the outstanding shares of Terasen Inc. for $35.91 per share. The total enterprise value of the transaction is approximately C$6.9 billion. The key details of the transaction are set out herein. We estimate that the transaction is priced at 24.6x estimated diluted 2005 EPS of $1.46, 2.62 x estimated 2005 book value per share of $13.66 and 11x EV/EBITDA. We believe the transaction is priced at the upper end of the relevant range. Subject to the approvals highlighted below, the transaction is expected to close by December 31, 2005.

Key Transaction Details: the key terms of the proposed transaction include the following:

- Prorated value of the offer is $35.91 per Terasen share is based on Kinder Morgan's share price and the C$/US$ exchange rates on July 29, of US$88.86 and $1.2233, respectively.
- 20% premium to the 20-day average closing price of Terasen common shares for the period ending July 29.
- Terasen holders will be able to elect:

    a. C$35.91 in cash;

    b. 0.3331 shares of Kinder Morgan common stock; or

    c. C$23.25 in cash plus 0.1165 shares of Kinder Morgan common stock.

    All elections will be subject to a proration such that cash elections are 65% of the total and stock elections are 35% of the total consideration paid.
- The requisite approval for the Arrangement Resolution is 75% of the votes cast on the Arrangement Resolution by Terasen Securityholders (other than Trans Mountain Pipe Line, which owns approximately 9.2 million common shares of Terasen Inc.) present in person or by proxy at the Terasen Meeting.
- The Terasen meeting will be held on or before October 31, 2005.
- There is a termination fee of $75 million (it appears as a U.S. dollar amount in Kinder Morgan's Form 8-K filing dated August 1, 2005 and a Canadian dollar amount in the Terasen presentation documents and in the press release disclosing the proposed Plan of Arrangement).
- The initial election date is December 20, 2005. If the effective date of the transaction is not reasonably likely to occur by the tenth business day after the initial election date, then this initial date will be extended.
- The transaction is subject to a number of regulatory approvals, including:
    - British Columbia Utilities Commission;

- Supreme Court of British Columbia (Plan of Arrangement was filed pursuant to Section 288 of the British Columbia Business Corporations Act);
- Hart-Scott-Rodino Antitrust Improvements Act.

It is not clear whether a ruling is required pursuant to the Competition Act (Canada).

Kinder Morgan is hosting a webcast at 8:30 a.m. EDT at www.kindermorgan.com and Terasen is hosting a conference call to discuss the transaction at 10:00 a.m. EDT at 1-877-375-5688.

We believe the following points are relevant about this proposed transaction:

- We believe the proposed transaction alleviates our two primary concerns with this stock: (1) the potential adverse effect on earnings per share associated with the expiry of the incentive tolling agreement relating to the Trans Mountain Pipe Line; and (2) the potential issuance of a significant amount of common equity to fund the company's robust project development profile and to increase the common equity capital at its regulated utility operations subject to a favourable decision in this regard by the British Columbia Utilities Commission by year-end 2005 or early 2006.
- We expected the company to act by acquiring companies in the natural gas distribution/transmission business in the Pacific Northwestern United States or combine with a Canadian-based pipeline company.
- As highlighted in Figure 1, the footprint of the combined company will be large and should have an enhanced competitive position.
- The transaction is priced at the upper end of the range of similar transactions and we do not expect a competing bid.

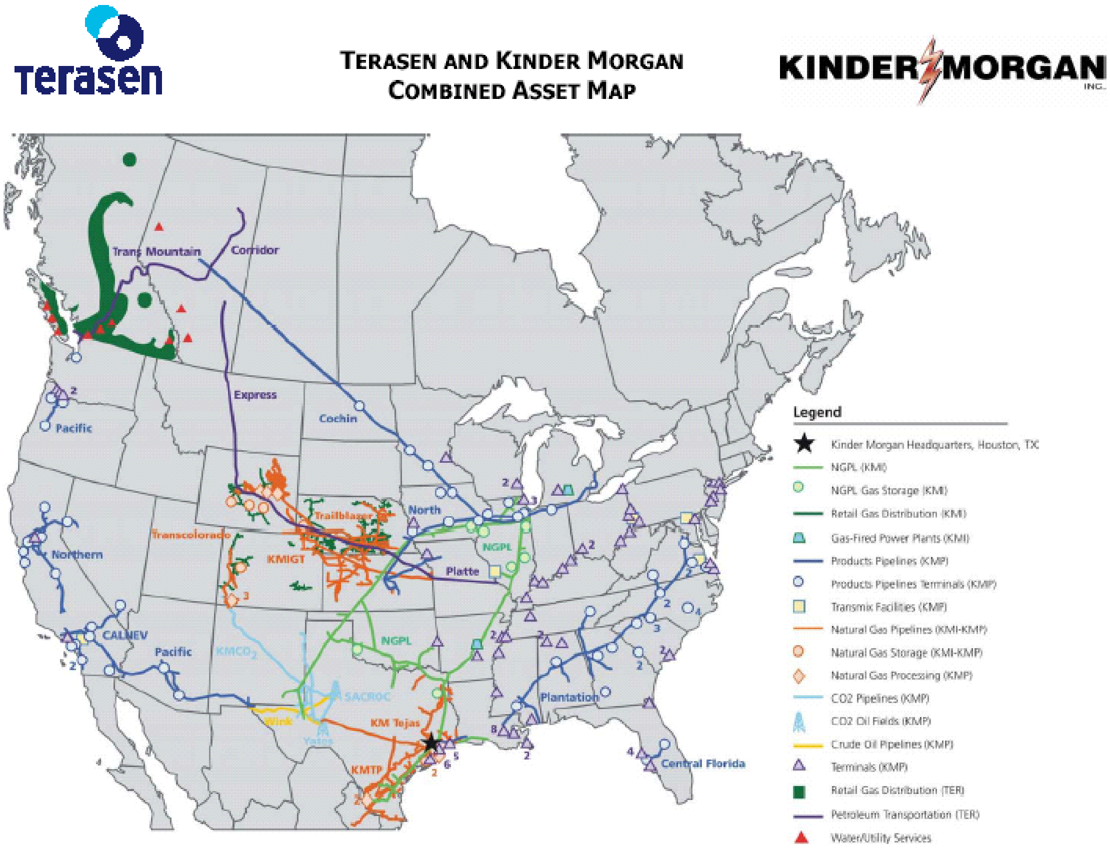
Valuation

Our revised target price of $35.95 is 23.6x 2006E diluted EPS of $1.52 (12.5%), 2.51 x estimated 2006 book value per share of $14.31 (12.5%) and a yield of 2.62% (75%), assuming 2006 dividends per share of $0.94. We believe the offer price is reasonable and we recommend that shareholders endorse it.

Recommendation

We believe the shares are reasonably valued and we rate them Market Perform.

Figure 1. Combined Assets – Terasen Inc. and Kinder Morgan



Source: Kinder Morgan Inc., Terasen Inc.

Table 1. Consolidated Summary Sheet

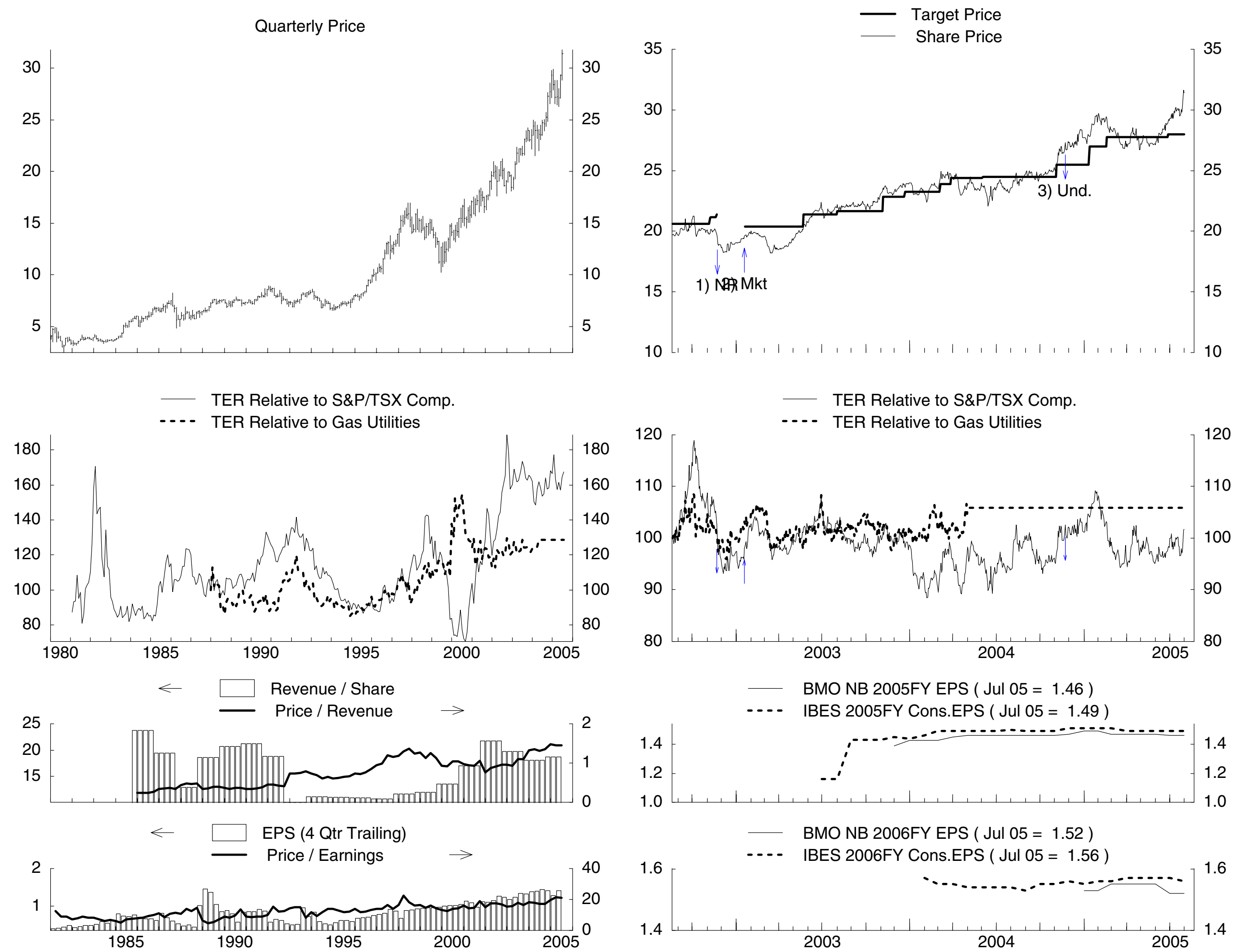
8/1/2005			Karen J. Taylor
Current Price:	$31.40		BMO Nesbitt Burns Inc.
12-Month Target Price:	$35.95		
Rate of Return:	17.36%	Recommendation:	Market Perform

	Year Ending December 31							
	1999	**2000**	**2001**	**2002**	**2003**	**2004**	**2005E**	**2006E**
Diluted EPS (Prior to One-Time Items)	$0.96	$0.99	$1.01	$1.26	$1.28	$1.39	$1.46	$1.52
Total EPS (Prior to One-Time Items)	$0.97	$1.00	$1.02	$1.27	$1.29	$1.40	$1.47	$1.53
Segmented EPS: Terasen Gas Utility	$0.68	$0.77	$0.89	$1.07	$0.93	$0.92	$0.91	$0.92
Trans Mountain Pipe Line	$0.26	$0.25	$0.27	$0.34	$0.54	$0.68	$0.73	$0.74
Other/**Water & Utility Services**	$0.04	($0.02)	($0.14)	($0.14)	($0.18)	$0.06	$0.09	$0.12
Corporate Activities	$0.00	$0.00	$0.00	$0.00	$0.00	($0.26)	($0.26)	($0.25)
Dividends	$0.58	$0.61	$0.65	$0.69	$0.77	$0.83	$0.90	$0.94
Payout Ratio	60.1%	61.3%	63.7%	54.5%	59.3%	59.0%	61.3%	61.3%
Average Shares (mm)	76.6	76.6	76.6	86.4	103.8	104.7	105.7	106.0
Net Book Value	$8.31	$9.02	$9.39	$12.10	$12.44	$13.04	$13.66	$14.31
Market Valuation								
Price: High	$15.50	$16.73	$18.20	$21.25	$24.00	$28.40	-	-
Price: Low	$10.50	$10.75	$14.88	$16.32	$18.18	$22.05	-	-
Price: Current	-	-	-	-	-	-	$31.40	-
P/E Ratio: High	16.0	16.24	17.84	16.73	18.60	20.30	-	-
P/E Ratio: Low	10.8	10.44	14.58	12.85	14.09	15.76	-	-
P/E Ratio: Current	-	-	-	-	-	-	21.4	20.5
Price/Book Value: High	1.92	1.85	1.94	1.76	1.93	2.18	-	-
Price/Book Value: Low	1.30	1.19	1.58	1.35	1.46	1.69	-	-
Price/Book Value: Current	-	-	-	-	-	-	2.30	2.19
Yield: High Price	3.76%	3.66%	3.57%	3.26%	3.19%	2.90%	-	-
Yield: Low Price	5.55%	5.70%	4.37%	4.24%	4.21%	3.74%	-	-
Yield: Current Price	-	-	-	-	-	-	2.87%	2.99%
Balance Sheet ($mm)								
Debt (S-T)	508.5	314.2	528.4	426.2	610.0	664.7	1,424.6	1,228.3
Debt (L-T)	1,120.9	1,561.9	1,717.1	2,123.4	2,301.1	2,166.6	1,483.7	1,841.4
Deferred Taxes/Other Deferred Items	35.0	47.3	56.8	58.1	67.5	209.4	209.4	209.4
Minority Interest	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Securities	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Shareholders' Equity	645.1	701.5	718.7	1,244.5	1,302.3	1,371.1	1,442.2	1,516.2
	2,384.5	2,749.9	3,146.0	3,977.2	4,405.9	4,536.8	4,684.9	4,920.3
Balance Sheet (%)								
Debt (S-T)	21.3%	11.4%	16.8%	10.7%	13.8%	14.7%	30.4%	25.0%
Debt (L-T)	47.0%	56.8%	54.6%	53.4%	52.2%	47.8%	31.7%	37.4%
Deferred Taxes/Other Deferred Items	1.5%	1.7%	1.8%	1.5%	1.5%	4.6%	4.5%	4.3%
Minority Interest	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred Securities	0.0%	4.5%	4.0%	3.1%	2.8%	2.8%	2.7%	2.5%
Shareholders' Equity	27.1%	25.5%	22.8%	31.3%	29.6%	30.2%	30.8%	30.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Income Statement ($mm)								
Net Profit After-Tax	82.8	80.7	77.9	109.5	133.9	146.5	155.2	162.7
Preferred Share Dividends	8.7	4.0	0.0	0.0	0.0	0.0	0.0	0.0
Earnings to Common Shareholders	74.1	76.7	77.9	109.5	133.9	146.5	155.2	162.7
Cash Flow from Operations ($mm)	117.0	173.3	53.6	311.4	267.7	342.0	323.9	341.3

Source: BMO Nesbitt Burns

BMO Nesbitt Burns

Terasen Inc. (TER)



FYE (Dec.)	EPS $	P/E	DPS $	Yield %	Payout %	BV $	P/B	ROE %
1982	0.48	7	0.28	8.1	58	3.01	1.1	16
1983	0.48	8	0.28	7.0	58	3.47	1.1	15
1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
2004	1.39	20	0.84	3.0	60	13.04	2.1	11
Current*	1.40	21	0.90	3.1	64	13.53	2.2	10
Average:		13		5.0	59		1.5	13.7
Growth(%):								
5 Year:	6.9		7.7			10.6		
10 Year:	8.6		7.2			7.4		
20 Year:	3.4		5.6			6.5		

* Current EPS is the 4 Quarter Trailing to Q2/2005.

TER - Rating as of 20-Aug-02 = Mkt

	Date	Rating Change	Share Price
1	21-Nov-02	Mkt to NR	$19.76
2	17-Jan-03	NR to Mkt	$19.39
3	23-Nov-04	Mkt to Und.	$26.95

Last Daily Data Point: July 29, 2005

BMO Nesbitt Burns

Company Risk Disclosure

In addition to the risks involved in investing in common stocks generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

General Disclosure

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Company Specific Disclosure

Disclosure 2: BMO Nesbitt Burns has undertaken an underwriting liability with respect to this issuer within the past 12 months.

Disclosure 3: BMO Nesbitt Burns has provided investment banking services with respect to this issuer within the past 12 months.

Disclosure 10: This issuer is a client (or was a client) of BMO Nesbitt Burns, HNC or an affiliate within the past 12 months: Investment Banking Services.

Distribution of Ratings

Rating Category	**BMO NB Rating**	**BMO NB Universe**	**BMO NB I.B. Clients***	**First Call Universe****
Buy	Outperform	43%	48%	47%
Hold	Market Perform	45%	39%	46%
Sell	Underperform	12%	13%	7%

* Reflects rating distribution of all companies where BMO NB has received compensation for Investment Banking services.
** Reflects rating distribution of all North American equity research analysts.

Ratings Key

BMO Nesbitt Burns uses the following ratings system definitions. **OP = Outperform** - Forecast to outperform the market; **Mkt = Market Perform** - Forecast to perform roughly in line with the market; **Und = Underperform** - Forecast to underperform the market; **(S) = speculative investment**; **NR = No rating at this time** - usually due to a company being in registration or coverage being initiated.

^ Market performance as measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company.

Prior to September 1, 2003, a fourth rating tier—Top Pick—was used to designate those stocks we felt would be the best performers relative to the market. Our six Top 15 lists which guide investors to our best ideas according to six different objectives (large, small, growth, value, income and quantitative) have replaced the Top Pick rating.

Dissemination of Research

BMO Nesbitt Burns Research publications are available via our web site http://bmonesbittburns.com. Institutional clients may also receive our research via FIRST CALL Research Direct and Multex. All of our research is made widely available at the same time to all BMO Nesbitt Burns client groups entitled to our research. Please contact your investment advisor or institutional salesperson for more information.

Additional Matters

TO U.S. RESIDENTS: HNC and/or BMO Nesbitt Burns Securities Ltd., affiliates of BMO Nesbitt Burns, furnish this report to U.S. residents and accept responsibility for the contents herein, except to the extent that it refers to securities of Bank of Montreal. Any U.S. person wishing to effect transactions in any security discussed herein should do so through HNC and/or BMO Nesbitt Burns Securities Ltd.

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"Nesbitt Burns" is a registered trade-mark of BMO Nesbitt Burns Corporation Limited, used under licence.

Terasen Inc.

(TER-TSX)

Stock Rating: Market Perform
Industry Rating: Market Perform

August 3, 2005
Research Comment
Pipelines

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

Conference Call Highlights; Market Perform Rating Maintained

Event

Terasen Inc. and Kinder Morgan each held a conference call to discuss the merits of the proposed transaction with buy and sell side analysts. The key highlights of each conference call are set out herein.

Impact

Neutral. We believe the proposed acquisition price of $35.91 per share is reasonable and recommend that shareholders endorse the proposed Plan of Arrangement.

Forecasts

Unchanged.

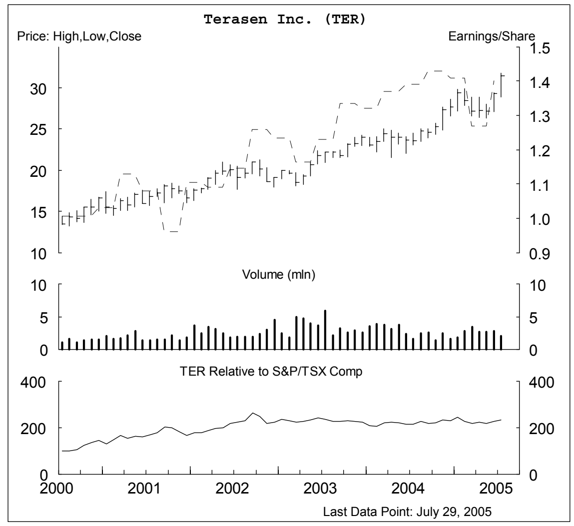
Valuation

Our target price of $35.95 is 23.6x 2006E diluted EPS of $1.52 (12.5%), 2.51x estimated 2006 book value per share of $14.31 (12.5%) and a yield of 2.62% (75%), assuming 2006 dividends per share of $0.94.

Recommendation

We believe the shares are reasonably valued and we rate them Market Perform.

Price (29-Jul)	$31.40	**52-Week High**	$31.78
Target Price	$35.95	**52-Week Low**	$23.38



(FY-Dec.)	2003A	2004A	2005E	2006E
EPS	$1.28	$1.39	$1.46	$1.52
P/E			21.5x	20.7x
CFPS	$2.58	$3.27	$3.08	$3.27
P/CFPS			10.2x	9.6x
Div.	$0.77	$0.83	$0.90	$0.94
EV ($mm)	$5,296	$5,725	$6,378	$6,543
EBITDA ($mm)	$503	$521	$588	$626
EV/EBITDA	10.5x	11.0x	10.9x	10.5x

Quarterly EPS	Q1	Q2	Q3	Q4
2003A	$0.71	$0.08	-$0.07	$0.60
2004A	$0.76	$0.10	-$0.03	$0.58
2005E	$0.62a	$0.23a	$0.09	$0.54

Dividend	$0.90	**Yield**	2.9%
Book Value	$13.53	**Price/Book**	2.3x
Shares O/S (mm)	105.5	**Mkt. Cap ($mm)**	$3,313
Float O/S (mm)	105.5	**Float Cap ($mm)**	$3,313
Wkly Vol (000s)	558	**Wkly $ Vol (mm)**	$15.2
Net Debt ($mm)	$3,018.7	**Next Rep. Date**	27-Oct (E)

Notes: Quarterlies reflect timing of equity issues
Major Shareholders: Widely held
First Call Mean Estimates: TERASEN INC (C$) 2005E: $1.49; 2006E: $1.56

Please refer to pages 5 to 7 for Disclosure Statements, including the Analyst's Certification.

Details & Analysis

Terasen Inc. and Kinder Morgan each held a conference call to discuss the merits of the proposed transaction with buy and sell side analysts. The key highlights of each conference call are set out herein.

Kinder Morgan Conference Call

Management of Kinder Morgan reviewed and reiterated the financial consequences of the proposed plan of arrangement:

- The transaction would be immediately accretive and permit the company to maintain a targeted EPS and dividend growth rate of 10%.
- The acquisition is consistent with Kinder Morgan's strategy of identifying the next "energy tsunami" and riding it; Kinder Morgan has acquired an infrastructure footprint in the oil sands development area. Kinder Morgan views the potential 1 million barrel per day increase in production to be the "next Permian Basin forming before your eyes" and it is, quite simply, a place that it wanted to be.
- The transaction is expected to be financed by approximately 20% equity and 80% debt; the total enterprise value of the transaction is estimated to be approximately US$5.6 billion. Kinder Morgan only plans to issue approximately US$1.06 billion in stock (approximately 12 million Kinder Morgan shares) and plans to assume debt and debt finance the US$4.54 billion. Assumed debt is approximately US$2.5 billion and debt to be issued by a Canadian-domiciled, wholly owned subsidiary of Kinder Morgan, is approximately US$2 billion. The company expects the transaction will be accretive by using a well-established structuring arrangement with an after-tax cost to Kinder Morgan of approximately 2% to 3%,.
- Kinder Morgan has not assumed that Terasen's oil pipelines are sold into a Canadian income trust in order to justify the transaction multiple.
- The company expects that an above average portion of its free cash flow will be used to reinvest in the project development opportunities in the oil sands production areas.
- Kinder Morgan's management indicated that Terasen's natural gas distribution business is a core asset; however, we believe there may be significant interest in Terasen Gas Vancouver Island and Terasen Gas Inc. by other Canadian utility players and due to the thin capitalization and low return characteristics of these businesses, that Kinder Morgan could potentially sell these assets post-closing. Terasen's water business is also not likely to be viewed as "core" and could be sold once the transaction closes.
- Kinder Morgan does not plan to offer Canadian shareholders of Terasen an exchangeable share.

- There was considerable confusion and uncertainty demonstrated by participants on the conference call about the regulatory process, the return characteristics, and risk profiles of Terasen's core strategic business units. As this information is disseminated in the market, some of the initial price enthusiasm for the transaction may be tempered.

Terasen Conference Call

The Terasen conference call had a number of highlights and we believe the following points are relevant:

- The sale represents reasonable value and we believe shareholders should endorse it.
- The sale mitigates the likely leadership, earnings dilution and EPS risks that we believe were likely to have emerged over the next 18 to 24 months.
- Approvals are required pursuant to the Competition Act Canada and the Investment Canada Act.
- No regulatory or political impediments are expected and the transaction is targeted to close by year-end 2005.
- Synergies from the transaction are expected to be limited—this is a transaction that is about "growth"—enhancing Terasen's ability to execute with lower cost capital, improved liquidity through Kinder Morgan and a more formidable footprint.
- The merger between Kinder Morgan and Terasen likely increases the intensity of the competition for intra-Alberta pipelines and take-away capacity out of Alberta. A number of scenarios are possible: (i) returns could decline further due to an increase in the intensity of competition between Enbridge, Terasen/Kinder Morgan, TransCanada Corporation, Pembina Pipeline Income Fund, and Inter Pipe Line Fund and Terasen/Kinder Morgan's lower cost of capital; and (ii) realized returns increase along with the risks that oil sands producers expect the pipeline transportation companies to bear. It is not clear that shippers/producers actually want the pipeline providers to take more risk, particularly if it means that the pipeline must be paid a higher return. We believe Kinder Morgan may have a higher tolerance for risk than Terasen on a stand-alone basis.

Valuation

Our target price of $35.95 is 23.6x 2006E diluted EPS of $1.52 (12.5%), 2.51x estimated 2006 book value per share of $14.31 (12.5%) and a yield of 2.62% (75%), assuming 2006 dividends per share of $0.94.

Recommendation

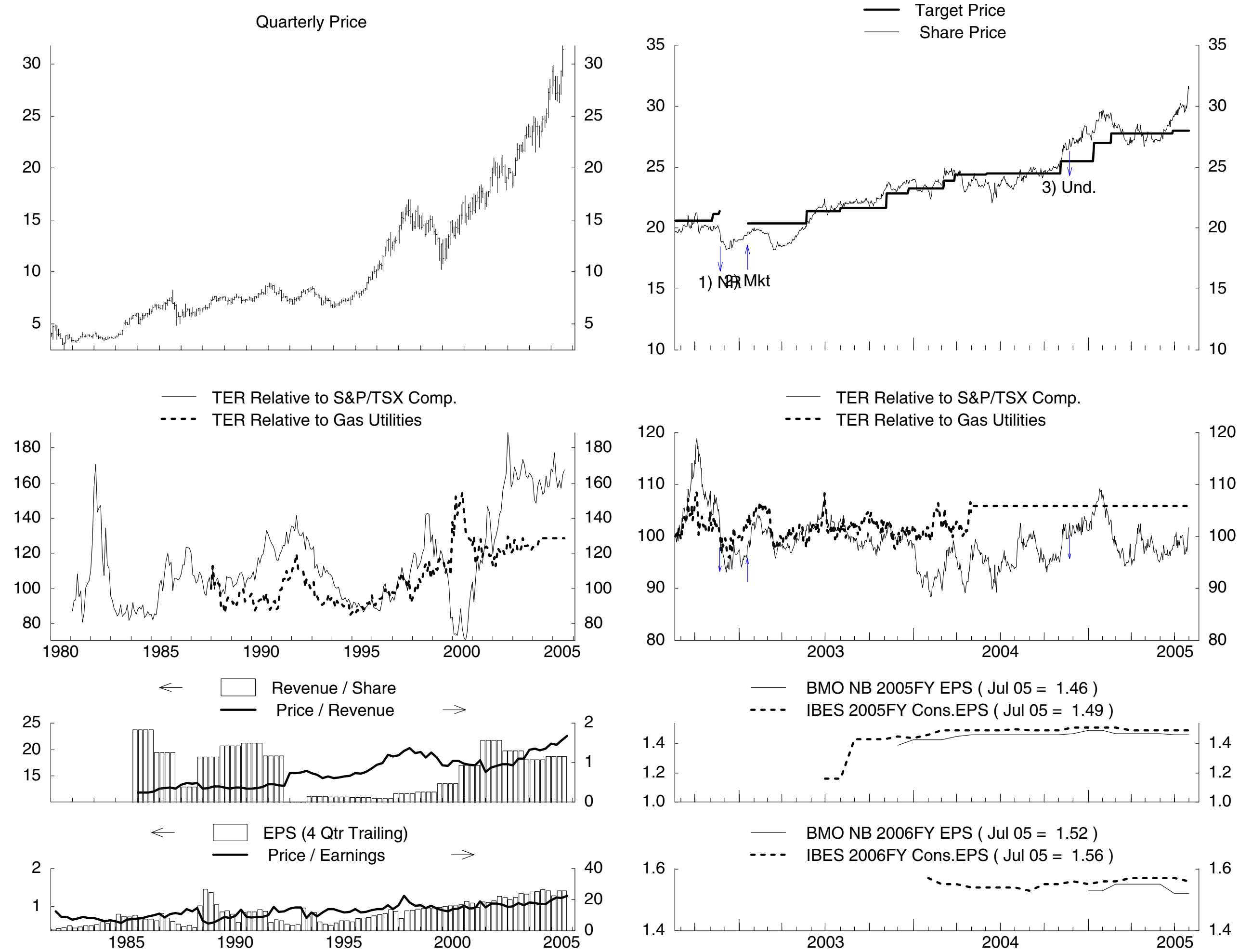
We believe the shares are reasonably valued and we rate them Market Perform.

Table 1. Consolidated Summary Sheet

02/08/2005								Karen J. Taylor
Current Price:	$36.00							BMO Nesbitt Burns Inc.
12-Month Target Price:	$35.95							
Rate of Return:	2.36%				Recommendation:		Market Perform	
	Year Ending December 31							
	1999	2000	2001	2002	2003	2004	2005E	2006E
Diluted EPS (Prior to One-Time Items)	$0.96	$0.99	$1.01	$1.26	$1.28	$1.39	$1.46	$1.52
Total EPS (Prior to One-Time Items)	$0.97	$1.00	$1.02	$1.27	$1.29	$1.40	$1.47	$1.53
Segmented EPS: Terasen Gas Utility	$0.68	$0.77	$0.89	$1.07	$0.93	$0.92	$0.91	$0.92
Trans Mountain Pipe Line	$0.26	$0.25	$0.27	$0.34	$0.54	$0.68	$0.73	$0.74
Other/**Water & Utility Services**	$0.04	($0.02)	($0.14)	($0.14)	($0.18)	$0.06	$0.09	$0.12
Corporate Activities	$0.00	$0.00	$0.00	$0.00	$0.00	($0.26)	($0.26)	($0.25)
Dividends	$0.58	$0.61	$0.65	$0.69	$0.77	$0.83	$0.90	$0.94
Payout Ratio	60.1%	61.3%	63.7%	54.5%	59.3%	59.0%	61.3%	61.3%
Average Shares (mm)	76.6	76.6	76.6	86.4	103.8	104.7	105.7	106.0
Net Book Value	$8.31	$9.02	$9.39	$12.10	$12.44	$13.04	$13.66	$14.31
Market Valuation								
Price: High	$15.50	$16.73	$18.20	$21.25	$24.00	$28.40	-	-
Price: Low	$10.50	$10.75	$14.88	$16.32	$18.18	$22.05	-	-
Price: Current	-	-	-	-	-	-	$36.00	-
P/E Ratio: High	16.0	16.24	17.84	16.73	18.60	20.30	-	-
P/E Ratio: Low	10.8	10.44	14.58	12.85	14.09	15.76	-	-
P/E Ratio: Current	-	-	-	-	-	-	24.5	23.5
Price/Book Value: High	1.92	1.85	1.94	1.76	1.93	2.18	-	-
Price/Book Value: Low	1.30	1.19	1.58	1.35	1.46	1.69	-	-
Price/Book Value: Current	-	-	-	-	-	-	2.63	2.52
Yield: High Price	3.76%	3.66%	3.57%	3.26%	3.19%	2.90%	-	-
Yield: Low Price	5.55%	5.70%	4.37%	4.24%	4.21%	3.74%	-	-
Yield: Current Price	-	-	-	-	-	-	2.50%	2.61%
Balance Sheet ($mm)								
Debt (S-T)	508.5	314.2	528.4	426.2	610.0	664.7	1,424.6	1,228.3
Debt (L-T)	1,120.9	1,561.9	1,717.1	2,123.4	2,301.1	2,166.6	1,483.7	1,841.4
Deferred Taxes/Other Deferred Items	35.0	47.3	56.8	58.1	67.5	209.4	209.4	209.4
Minority Interest	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preferred Securities	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Shareholders' Equity	645.1	701.5	718.7	1,244.5	1,302.3	1,371.1	1,442.2	1,516.2
	2,384.5	2,749.9	3,146.0	3,977.2	4,405.9	4,536.8	4,684.9	4,920.3
Balance Sheet (%)								
Debt (S-T)	21.3%	11.4%	16.8%	10.7%	13.8%	14.7%	30.4%	25.0%
Debt (L-T)	47.0%	56.8%	54.6%	53.4%	52.2%	47.8%	31.7%	37.4%
Deferred Taxes/Other Deferred Items	1.5%	1.7%	1.8%	1.5%	1.5%	4.6%	4.5%	4.3%
Minority Interest	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred Securities	0.0%	4.5%	4.0%	3.1%	2.8%	2.8%	2.7%	2.5%
Shareholders' Equity	27.1%	25.5%	22.8%	31.3%	29.6%	30.2%	30.8%	30.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Income Statement ($mm)								
Net Profit After-Tax	82.8	80.7	77.9	109.5	133.9	146.5	155.2	162.7
Preferred Share Dividends	8.7	4.0	0.0	0.0	0.0	0.0	0.0	0.0
Earnings to Common Shareholders	74.1	76.7	77.9	109.5	133.9	146.5	155.2	162.7
Cash Flow from Operations ($mm)	117.0	173.3	53.6	311.4	267.7	342.0	323.9	341.3

Source: BMO Nesbitt Burns

Terasen Inc. (TER)



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1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
2004	1.39	20	0.84	3.0	60	13.04	2.1	11
Current*	1.40	22	0.90	2.9	64	13.53	2.3	10
Average:		13		5.0	59		1.5	13.7
Growth(%):								
5 Year:	6.9		7.7			10.6		
10 Year:	8.6		7.2			7.4		
20 Year:	3.4		5.6			6.5		

* Current EPS is the 4 Quarter Trailing to Q2/2005.

TER - Rating as of 20-Aug-02 = Mkt

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BMO Nesbitt Burns

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Analyst's Certification

I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

General Disclosure

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Rating Category	**BMO NB Rating**	**BMO NB Universe**	**BMO NB I.B. Clients***	**First Call Universe****
Buy	Outperform	43%	48%	47%
Hold	Market Perform	45%	39%	46%
Sell	Underperform	12%	13%	7%

* Reflects rating distribution of all companies where BMO NB has received compensation for Investment Banking services.
** Reflects rating distribution of all North American equity research analysts.

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^ Market performance as measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company.

Prior to September 1, 2003, a fourth rating tier—Top Pick—was used to designate those stocks we felt would be the best performers relative to the market. Our six Top 15 lists which guide investors to our best ideas according to six different objectives (large, small, growth, value, income and quantitative) have replaced the Top Pick rating.

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Terasen Inc.

August 3, 2005
Research Comment
Corporate Debt – Pipelines & Utilities

Kinder Morgan Acquisition Appears Credit Negative for Bondholders

Sue McNamara, CFA
(416)-359-4584
sue.mcnamara@bmonb.com

Event

On August 1, 2005, Kinder Morgan Inc. announced a definitive agreement to acquire all of the outstanding shares of Terasen Inc.

Impact

Negative.

Key Points

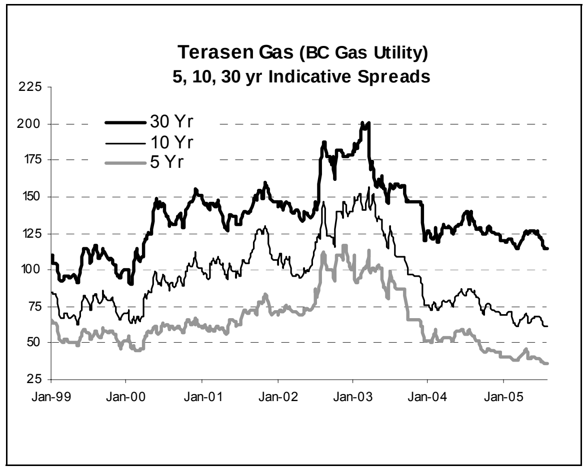
Kinder Morgan Inc. has stated that it intends to finance the acquisition with a combination of cash and equity up to a maximum proration of 65% cash and 35% equity. The company also stated on its conference call that it plans to fund the cash portion of the acquisition with debt financing provided by a Canadian subsidiary of Kinder Morgan Inc. After the closing of the transaction, Kinder Morgan expects that its debt to total capital ratio will likely increase to 56% versus 36.8% at June 30, 2005.

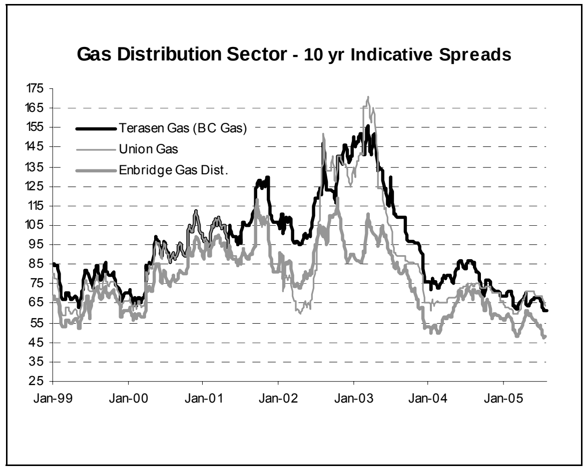
Recommendation

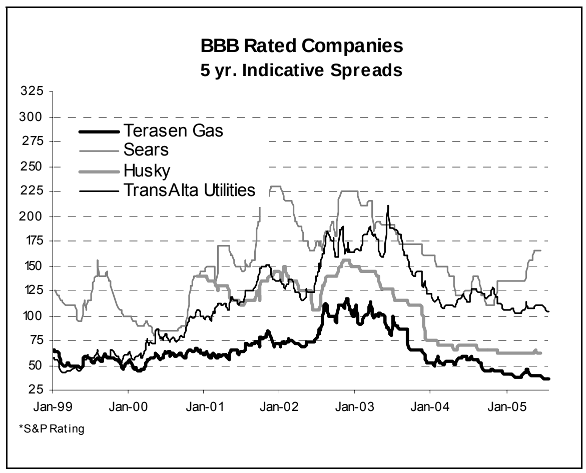
In 2005, Terasen Inc.'s 5-year, 10-year and 30-year generic credit spreads tightened by 8, 12 and 10 basis points, respectively. We note that Terasen Inc.'s credit spreads likely reflect a scarcity premium, as the holding company only has two maturities outstanding totalling $300 million. We believe that the acquisition is a credit negative and that the company's spreads will likely widen over the next 12 months. We believe that there is a risk that the credit ratings of the company could be negatively affected by the acquisition. As highlighted in detail within, Moody's, DBRS and S&P have placed Terasen Inc.'s credit Under Review with Negative Implications. S&P and DBRS have also placed KMI's credit ratings Under Review with Negative Implications. We note that the acquisition does address some of our previous credit concerns on Terasen Inc., namely the risk that any significant spending by Terasen Inc. either through development projects or acquisitions (depending on how it is financed) would be a credit event, as the company is relatively thinly capitalized.

Senior Unsecured Debt Ratings

DBRS	S&P	Moody's
A (Low)	BBB-	A3
UR - Negative	CW - Negative	UR - Negative







Please refer to pages 6 to 7 for Disclosure Statements, including the Analyst's Certification.

Acquisition

On August 1, 2005, Kinder Morgan Inc. announced a definitive agreement to acquire all of the outstanding shares of Terasen Inc. As part of the acquisition, Kinder Morgan will assume all of Terasen Inc's debt. The company had long- and short-term debt outstanding totalling $2.6 billion and $360.5 million, respectively, at June 30, 2005, of which $300 million was issued at the Terasen Inc. holding company level. Terasen Inc. has no debt maturities in the remainder of 2005, whereas Terasen Gas (100% - Terasen Inc.) has debt maturities of $350 million in 2005. We believe that the maturities will likely be refinanced or repaid with short-term debt issuance. The debt will likely mature prior to the expected close of the transaction (year-end 2005).

Kinder Morgan Inc. has stated that it intends to finance the acquisition with a combination of cash and equity up to a maximum proration of 65% cash and 35% equity. The company also stated on its conference call that it plans to fund the cash portion of the acquisition with debt financing provided by a Canadian subsidiary of Kinder Morgan Inc. After the closing of the transaction, Kinder Morgan expects that its debt to total capital ratio will likely increase to 56% versus 36.8% at June 30, 2005. For additional views on the acquisition, please refer to the equity research comment on Terasen Inc. by BMO Nesbitt Burns' equity analyst Karen Taylor, dated August 2, 2005.

Credit Ratings

Terasen Inc. Ratings

Terasen Inc.'s senior unsecured debt is rated A(Low), BBB- and A3 by DBRS, S&P and Moody's, respectively. The outlook is CreditWatch Negative by S&P and Under Review – Negative by DBRS and Moody's.

S&P has placed the credit ratings of Terasen Inc. and Terasen Gas on CreditWatch with Negative Implications. The outlook change reflects S&P's preliminary assessment that upon the closing of the transaction, the companies' credit quality will be assessed on a consolidated basis and will likely be equalized with the ratings on KMI, reflecting the same level of default risk. S&P states that the addition of significant amounts of debt will weaken KMI's balance sheet and debt protection measures. S&P must determine whether the effects of increased leverage eclipse the benefits of the addition of Terasen's asset base. Terasen's current credit quality reflects the average business profiles of the company's natural gas distribution business and liquids pipeline systems, offset by a weak financial profile. S&P further states that the company's below average deemed equity levels and allowed ROEs currently constrain the ratings on Terasen. We note that S&P provides ratings coverage of the Terasen companies, based on publicly available information.

DBRS has placed the ratings of Terasen Inc. Under Review with Negative Implications. DBRS states that the proposed transaction creates uncertainties with respect to the potential financing policies of Terasen, which could potentially have negative implications for its future financial profile. DBRS believes that ownership by a lower rated entity, KMI, could expose Terasen to increased dividend payments to support KMI's higher debt load. In its review, DBRS will also focus on the impact on the business and financial risk profile of the combined entity as well as tax, legal and regulatory issues of the cross-border transaction. We note that DBRS has maintained its Stable outlook on the A rated credit of Terasen Gas.

Moody's has placed the ratings of Terasen Inc. and Terasen Gas under review for possible downgrade. The change in outlook reflects the lower credit rating of KMI (Baa3) and its weak standalone financial profile relative to its peers. Moody's intends to assess what financial strategies KMI might employ for Terasen and what their implications might be for both Terasen and Terasen Gas. Moody's also states that Terasen Gas' ratings are being reviewed due to the lack of ringfencing or other restrictions that could limit its ability to make dividend payments to Terasen Inc. Moody's rates Terasen Inc. one notch below that senior unsecured rating of Terasen Gas at A2. The one-notch differential reflects the structural subordination of Terasen's debt to operating subsidiary debt at Terasen Gas, Terasen Gas Vancouver Island, Corridor, Trans Mountain and Express.

Kinder Morgan Inc. Ratings

DBRS rates Kinder Morgan Inc.'s senior unsecured debt BBB. The outlook is Under Review with Negative Implications. Based on its preliminary review, DBRS states that it expects the proposed transaction to have a positive effect on KMI's business risk as a result of the increased scope and scale of the company's regulated pipeline and gas distribution operations and growth potential. Conversely, DBRS states that the acquisition will likely increase KMI's balance sheet leverage to pre-2001 levels, which is relatively high and is expected to remain so for a few years.

S&P's credit rating on KMI is BBB. The outlook was changed to CreditWatch with Negative Implications from Stable following the announcement of the Terasen acquisition. The change in outlook reflects KMI's plan to increase financial leverage to fund the acquisition. S&P states that KMI's credit quality could be preserved if the potential improvement in KMI's business profile is capable of fully offsetting the higher financial risk. S&P stated in its latest summary on KMI (dated July 1, 2005) that the company's ratings are anchored by the company's regulated interstate natural gas pipeline and retail distribution assets, as well as the historically steady distributions that KMI receives from KMP.

Moody's rates the KMI's debt securities Baa2 with a Stable outlook. The company's credit rating and Stable outlook were affirmed following the acquisition announcement. Moody's believes that KMI will likely have sufficient free cash flow to cover the incremental interest expense and dividends from the acquisition financing. Moody's states that maintaining KMI's rating and outlook will entail achievement of the incremental earnings and cost savings that the company forecasts from Terasen as well as discipline in its dividend payouts. Moody's states that significant deviation from these expectations will cause the ratings agency to reassess KMI's ratings and outlook.

Recommendation

In 2005, Terasen Inc.'s 5-year, 10-year and 30-year generic credit spreads tightened by 8, 12 and 10 basis points, respectively. We note that Terasen Inc.'s credit spreads likely reflect a scarcity premium as the holding company has only two maturities outstanding, totalling $300 million. We believe that the acquisition is a credit negative and that the company's spreads will likely widen over the next 12 months. We believe that there is a risk that the credit ratings of the company could be negatively affected by the acquisition. As highlighted in detail above, Moody's, DBRS and S&P have placed Terasen Inc.'s credit Under Review with Negative Implications. S&P and DBRS have also placed KMI's credit ratings Under Review with Negative Implications. We note, however, that the acquisition does address some of our previous credit concerns on Terasen Inc., namely the risk that any significant spending by Terasen Inc., either through development projects or acquisitions (depending on how it is financed), would be a credit event, as the company is relatively thinly capitalized. We also believe that the following credit risks still remain:

1. The expiry of the Trans Mountain system's negotiated toll settlement at the end of 2005: the company is currently in negotiations with shippers to extend or renew the toll agreement. The company's earnings and cash flow in 2006 could be negatively affected by the outcome of the negotiation.
2. Regulatory risk at Terasen Gas: On July 11, the British Columbia Utilities Commission (BCUC) issued an Order and Notice of Procedural Conference regarding an application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. to determine the appropriate return on equity and capital structure and to review and revise the automatic adjustment mechanism used by the BCUC to establish the allowed return on equity, annually (please see Karen Taylor's equity comment on Terasen Inc. dated July 15, 2005 for more details).

Terasen Inc.

Maturity Schedule

Company	Coupon	Maturity	Amount ($mm)	Instrument	Issue Date	Issue Spread	Callable	CUSIP	Outstanding ($mm)
Terasen Gas Inc.	9.800%	9-Feb-05	$40	MTNs	9-Feb-95	NA	Non-callable	05534ZAA4	$40
Terasen Gas Inc.	8.250%	29-Jun-05	$5	MTNs	29-Jun-95	NA	Non-callable	05534ZAB2	$5
Terasen Gas Inc.	6.500%	20-Jul-05	$200	MTNs	20-Jul-00	57.0 bps	Non-callable	05534ZAG1	$200
Terasen Gas Inc.	Floating[1]	26-Sep-05	$150	Floating Rate Notes	26-Sep-03	NA	Non-callable	88079ZAAZ	$150
Terasen Gas Inc.	4.850%	8-May-06	$100	MTNs	8-May-03	NA	Non-callable	88079ZAA1	$100
Terasen Gas Inc.	6.150%	31-Jul-06	$100	MTNs	30-Jul-01	73.0 bps	Make Whole + 18 bps	88079ZAL0	$100
Terasen Gas Inc.	9.750%	17-Dec-06	$20	Retractable Debentures	17-Dec-86	NA	Non-callable	NA	$20
Terasen Gas Inc.	6.500%	16-Oct-07	$100	MTNs	16-Oct-00	75.0 bps	Make Whole + 18 bps	05534ZAH9	$100
Terasen Gas Inc.	6.200%	2-Jun-08	$188	MTNs	21-Oct-97	80.0 bps	Non-callable	05534ZAC0	$188
Terasen Gas Inc.	6.300%	1-Dec-08	$200	MTNs	30-Nov-01	NA	Make Whole + 27 bps	11058ZAA8	$200
Terasen Gas Inc.	10.750%	8-Jun-09	$60	Debentures	8-Jun-89	NA	Make Whole + 40 bps	457452AH3	$60
Terasen Pipelines (Corridor)	4.240%	2-Feb-10	$150	Senior Unsecured	1-Feb-05	65.5 bps	Make Whole + 14 bps	88079VAA0	$150
Terasen Pipelines Inc.	11.500%	1-Jun-10	$35	Senior Unsecured	20-Jun-90	NA	Make Whole + 50 bps	NA	$35
Express Pipeline	6.470%	31-Dec-13	US$150	Senior Secured Notes	6-Feb-98	NA	Make Whole + 25 bps	30217VAA5	US$112.8
Terasen Inc.	5.560%	15-Sep-14	$125	MTNs	10-Sep-04	93.0 bps	Make Whole + 23 bps	88079ZAB9	$125
Terasen Pipelines (Corridor)	5.033%	2-Feb-15	$150	Senior Unsecured	1-Feb-05	81.1 bps	Make Whole + 19 bps	88079VAB8	$150
Terasen Gas Inc.	11.800%	30-Sep-15	$75	Mortgage	3-Dec-90	NA	Non-callable	05534RAA2	$75
Terasen Gas Inc.	10.300%	30-Sep-16	$200	Mortgage	21-Nov-91	104.0 bps	Make Whole + 35 bps	05534RAB0	$200
Express Pipeline	7.390%	31-Dec-19	US$250	Subordinated Secured Notes	6-Feb-98	NA	Make Whole + 50 bps	30217VAD9	US$239.2
Terasen Gas Inc.	6.950%	21-Sep-29	$150	MTNs	21-Sep-99	112.0 bps	Make Whole + 28 bps	05534ZAF3	$150
Terasen Gas Inc.	6.500%	1-May-34	$150	MTNs	29-Apr-04	127.0 bps	Make Whole + 31 bps	88078ZAB0	$150
Terasen Inc.	8.000%	19-Apr-40	$125	Subordinated Debentures	19-Apr-00	235.0 bps	Make Whole + 55 bps	05534KAA7	$125

[1] 35 basis points to 3 month Bankers Acceptances

Ownership Structure

Widely held.

Credit Facilities

Company	Facility Size	Amount Drawn Q2/04	Amount Drawn FY 2003	Letters of Credit Q2/04	Letters of Credit FY 2003	Maturity	Type
Terasen Inc.	$300	$200.0	$200.0			NA	Lines of Credit
Terasen Gas Inc.	$500	$70.0	$353.0			NA	Lines of Credit
Terasen Gas Vancouver	$213	$160.0	$160.0			NA	Lines of Credit
Corridor Pipelines	$525	$525.0	$525.0			NA	Lines of Credit

Shelf Prospectus

Company	Type	Amount	Remaining	Date	Expiry	Instruments
Terasen Gas Inc.	Shelf	$700	$550	10-Dec-03	10-Jan-05	MTNs
Terasen Inc.	Shelf	$800	$800	10-Dec-03	10-Jan-05	Unsecured Debentures

Pension Summary

	Pension Benefit Plans FY 2004 ($mm)	Pension Benefit Plans FY 2003 ($mm)	Other Benefit Plans FY 2004 ($mm)	Other Benefit Plans FY 2003 ($mm)
Accrued Benefit Obligation	298.0	276.7	67.3	61.0
Plan Assets	274.5	255.3	-	-
Funded Status	(23.5)	(21.4)	(67.3)	(61.0)
Accrued Benefit Asset (Liability) Net of Valuation Allowance	1.5	4.1	(32.3)	(24.6)
Discount Rate	6.00%	6.25%	6.00%	6.25%
Expected Long-term Rate of of Return on Assets	7.50%	7.50%	NA	NA
Rate of Future Increase in Compensation	3.50%	3.39%	NA	NA

Historical Ratings

DBRS Rating	DBRS Trend	DBRS Date	S&P Rating	S&P Trend	S&P Date	Moody's Rating	Moody's Trend	Moody's Date
A (L)	Stable	4-Apr-00	BBB	Stable	14-Nov-01	A3	Stable	8-Nov-01
			BBB	Credit Watch Negative	19-Nov-02	A3	Under Review - Negative	19-Nov-02
			BBB-	Stable	26-Jun-03	A3	Stable	12-Dec-02

Note: On March 12, 2004, Terasen Inc. disengaged its relationship with S&P. The rating agency will continue to provide ratings on Terasen and its subsidiaries using public information.

Company Risk Disclosure

In addition to the risks involved in investing in corporate debt securities generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

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Terasen Inc

(TER-TSX)

August 8, 2005
Brief Research Note
Pipelines

Stock Rating: Market Perform
Stock Price: $35.90
Target Price: $35.95

Karen Taylor, CFA
(416) 359-4304
Karen.Taylor@bmonb.com
Assoc: Keith Carpenter

Tax Status of Kinder Morgan Plan of Arrangement

Impact

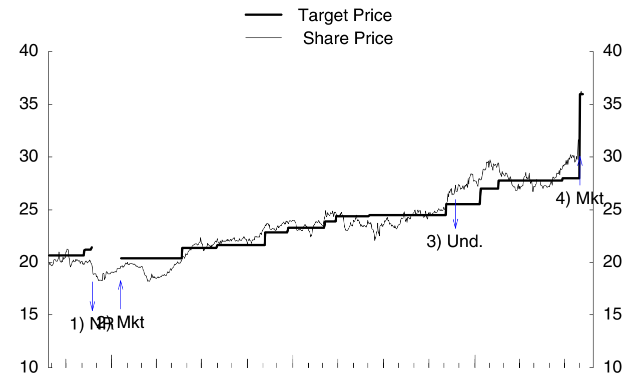
Neutral

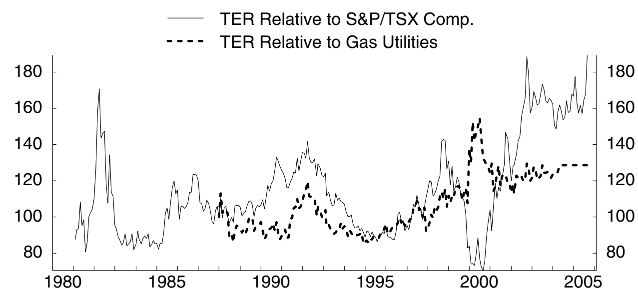
Details & Analysis

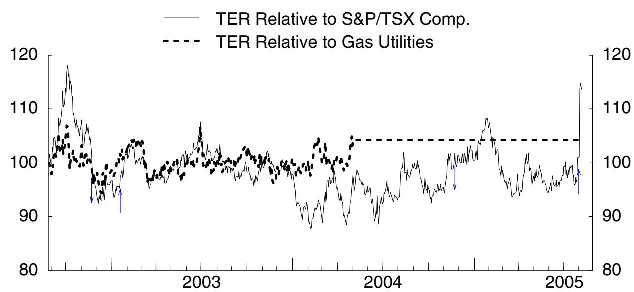
We have had a number of questions relating to the tax status of the planned acquisition of Terasen Inc. by Kinder Morgan Inc (KMI-NYSE). We have confirmed our understanding with Terasen that regardless of whether an investor elects cash, Kinder Morgan shares or a combination thereof, the transaction will be a fully taxable event for shareholders. We believe that the shares of Terasen are reasonably valued and we rate them Market Perform.

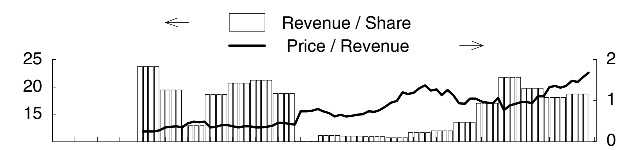
Please refer to pages 2 to 4 for Disclosure Statements, including the Analyst's Certification.

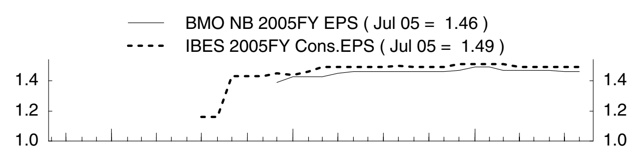
Terasen Inc. (TER)

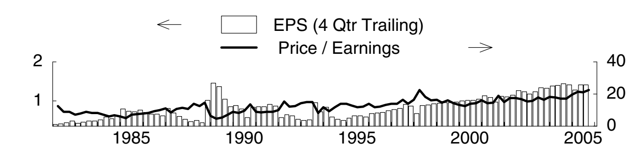


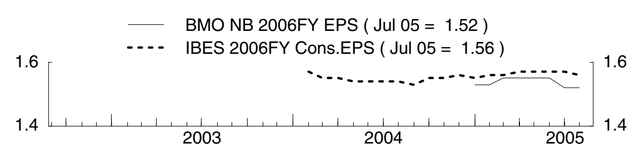












FYE (Dec.)	EPS $	P/E	DPS $	Yield %	Payout %	BV $	P/B	ROE %
1982	0.48	7	0.28	8.1	58	3.01	1.1	16
1983	0.48	8	0.28	7.0	58	3.47	1.1	15
1984	0.61	6	0.28	7.5	45	3.63	1.0	17
1985	0.76	8	0.30	5.0	39	3.84	1.6	20
1986	0.61	11	0.36	5.4	59	4.01	1.7	15
1987	0.53	11	0.34	6.0	65	4.07	1.4	13
1988	1.01	6	0.34	5.3	34	4.66	1.4	23
1989	0.85	9	0.37	4.9	44	5.05	1.5	18
1990	0.83	9	0.41	5.6	49	5.44	1.4	16
1991	0.87	10	0.45	5.3	52	6.46	1.3	15
1992	0.52	14	0.45	6.1	87	6.23	1.2	8
1993	0.72	12	0.45	5.4	63	6.50	1.3	11
1994	0.49	14	0.45	6.7	93	6.62	1.0	7
1995	0.58	14	0.45	5.6	78	6.85	1.2	9
1996	0.74	14	0.45	4.4	61	7.64	1.3	10
1997	0.86	16	0.50	3.6	58	7.77	1.8	11
1998	0.93	16	0.56	3.7	61	7.71	2.0	12
1999	0.97	13	0.59	4.6	61	8.18	1.6	12
2000	1.03	16	0.62	3.7	60	8.93	1.9	12
2001	2.21	15	0.66	4.0	60	9.33	1.8	24
2002	1.26	15	0.72	3.8	58	12.00	1.6	12
2003	1.28	18	0.78	3.3	59	12.53	1.9	10
2004	1.39	20	0.84	3.0	60	13.04	2.1	11
Current*	1.40	22	0.90	2.9	64	13.53	2.3	10
Average:		13		5.0	59		1.5	13.7
Growth(%):								
5 Year:	6.9		7.7			10.6		
10 Year:	8.6		7.2			7.4		
20 Year:	3.4		5.6			6.5		

* Current EPS is the 4 Quarter Trailing to Q2/2005.

TER - Rating as of 27-Aug-02 = Mkt

	Date	Rating Change	Share Price
1	21-Nov-02	Mkt to NR	$19.76
2	17-Jan-03	NR to Mkt	$19.39
3	23-Nov-04	Mkt to Und.	$26.95
4	1-Aug-05	Und.to Mkt	$31.40

Last Daily Data Point: August 5, 2005

Company Risk Disclosure

In addition to the risks involved in investing in common stocks generally, we also highlight the following risks that pertain to this company. Terasen could be exposed to significant operational disruptions and environmental liability in event of product spill or accident. Through the regulatory process, the BCUC approves the return on equity for Terasen Gas and Terasen Gas Vancouver Island. Changes in regulation may adversely affect performance. The company's hydrocarbon pipelines are dependent upon the continued availability of crude oil and bitumen. Transportation volumes on the TransMountain Pipeline are sensitive to demand from Washington state refineries, and overseas demand for transportation of Canadian crude oil via tanker.

Albian Sands is the sole shipper on the Corridor Pipeline. The company's natural gas distribution operations are dependent upon the continued availability of natural gas and the relative attractiveness of natural gas versus electricity.

Analyst's Certification

I, Karen Taylor, CFA, hereby certify that the views expressed in this report accurately reflect my personal views about the subject securities or issuers. I also certify that I have not, am not, and will not receive, directly or indirectly, compensation in exchange for expressing the specific recommendations or views in this report.

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Buy	Outperform	43%	48%	47%
Hold	Market Perform	45%	39%	46%
Sell	Underperform	12%	13%	7%

* Reflects rating distribution of all companies where BMO NB has received compensation for Investment Banking services.

** Reflects rating distribution of all North American equity research analysts.

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Market performance as measured by a benchmark index such as the S&P/TSX Composite Index, S&P 500, Nasdaq Composite, as appropriate for each company.

Prior to September 1, 2003, a fourth rating tier—Top Pick—was used to designate those stocks we felt would be the best performers relative to the market. Our six Top 15 lists which guide investors to our best ideas according to six different objectives (large, small, growth, value, income and quantitative) have replaced the Top Pick rating.

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Additional Matters

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Terasen Inc.

(TER : TSX : CAD$29.35 | Issued 104.8M)

HOLD | Target price: CAD$28.00

Bob Hastings
(604) 643-0177
bob_hastings@canaccord.com
Juan Plessis
(604) 643-0181
juan_plessis@canaccord.com

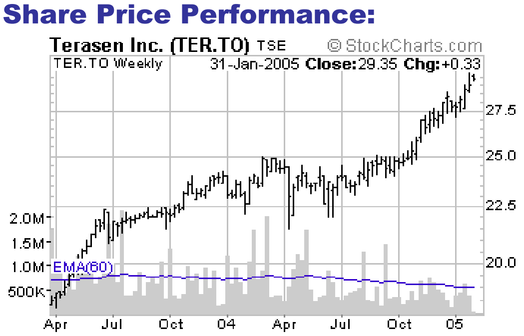
Company Statistics:

Recommendation:	**HOLD**
12-month target price:	$28.00
Price:	$29.35
52 Week Range:	$21.50-29.79
Avg. Daily Vol. (000):	45.4
Market Capitalization (M):	$3,075.9
Shares Out. (M) basic:	104.8
Current Dividend Yield:	2.9%
Current Dividend/Share:	$0.84
Bk Value/Shr:	$13.06

Earnings Summary:

FYE Dec	2003A	2004E	2005E	2006E
EPS:	$1.32	$1.40	$1.50	$1.60
P/E:	22.3x	21.0x	19.6x	18.3x
CFPS:	$2.75	$2.90	$2.95	$3.05
P/CF:	10.7x	10.1x	10.0x	9.6x

Share Price Performance:



Company Description:

Terasen provides energy and utility services in western Canada and the US Pacific Northwest, through two regulated business segments. The Natural Gas Distribution business includes transmission and distribution of natural gas to customers in BC and provides transportation services through the pipeline. The Petroleum Transportation business transports oil and refined products from Alberta to BC and delivers crude oil to refineries in the US.

All amounts in CAD unless otherwise noted.

SHIPPERS WANT MORE PIPELINE CAPACITY

Event: Terasen received solid expressions of interest from shippers, proving out a need for new pipeline facilities to the west coast. Now the more difficult part has to be decided: where are the most attractive markets (Asia or California); the preferred pipeline proposal (Terasen or Enbridge); the economics of the project; the signing of long term commitments with shippers, and; gaining regulatory approval (including environmental and native acceptance).

Impact: Little impact until it becomes clear how much support Terasen has from producers. It is the producers who will pay for the tolls, and they have to decide which route and which project(s) they will financially support. This should be better known in the late spring.

Valuation: We are maintaining our HOLD rating and $28.00 target price on the shares of Terasen Inc. Our target price is derived from a combination of valuation metrics which include earnings and dividend yields relative to long term interest rates, dividend discount models, and earnings and cash flow multiples relative both to historical valuation and its utility and pipeline peers.

Summary

Terasen received expressions of interest from 17 different parties to proceed to the next phase of the Trans Mountain system expansion project (TMX) to carry growing oil sands production to the west coast and offshore markets. The Expression of Interest process took place over the past two months and indicated the need for additional capacity out of Alberta by 2008. It is of course no surprise that shippers see a need for more capacity, but it is the timing, the size, the eventual route and the company that will build it that are more difficult questions. We view the announcement as positive since it confirms that there is definitely interest, but would not award much value to either Terasen or Enbridge until it becomes clearer which project(s) will be supported by the producers. Certainly, both are likely to be involved in expansion opportunities, but the size and timing are still speculative.

Producers love a good competition, particularly when they can challenge two pipeline companies to compete to offer the best and most economical project for producers. That process spurs more creative solutions and lower costs for the shippers (lower returns for the pipelines?). At this point, both Terasen and Enbridge have spent considerable time and effort attracting interest from producers and we suspect that both will have their supporters. We fear this competition, however, has the potential to cause significant delays during the required regulatory approval process, particularly if any rolled-in toll methodology is employed (likely to some extent).

Details of TMX

TMX Phase One is designed to increase the Trans Mountain's capacity 75,000 bpd to 300,000 bpd by the end of 2008. It will add 35,000 bpd by the end of 2006 through the addition of pump stations (about $205 million), and another 40,000 bpd by the end of 2008 by the looping of 178 kilometres of its system (about $365 million).

Terasen will proceed to the next phase if shipper interest warrants, and undertake additional looping system to existing facilities in Burnaby British Columbia and/or extend the Trans Mountain pipeline to a new terminal on BC's north coast in Kitimat or Prince Rupert. This could increase system capacity up to 850,000 bpd in 2010 at an incremental cost of around $1.6-2.4 billion, depending whether a southern or northern route is chosen.

The staged expansion of TMX is designed by Terasen to align incremental oil sands production from Alberta with market demands on the West Coast of Canada, the United States and Asia. Both phases appear to total $2.2-2.9 billion to ship an extra 625,000 bpd. This compares to the approximate $2.5 billion cost for Enbridge's Gateway project to ship 400,000 b/d a year earlier by 2009. Experience tells us that the numbers are likely not all that comparable, expressions of interest do not always materialize into contracts and the approval process may be long.

Investment risks

Some of the specific risk factors that pertain to the projected six to 12 month stock price target for Terasen are as follows: a) Terasen could be exposed to significant operational disruptions and environmental liability in the event of a petroleum product spill or an accident involving natural gas; b) The unprecedented increase in the market price of natural gas in 2000 significantly eroded the competitive advantage of natural gas relative to alternative sources of energy, notably electricity, in British Columbia; c) Terasen's earnings are sensitive to interest rates in several ways. Some outstanding debt has net exposure to short-term interest rates, and is not subject to regulatory interest deferral accounts. In addition, the allowed returns on equity for BC Gas Utility, Centra Gas and Corridor are determined by formulae that result in lower allowed ROEs if long-term Canada bond yields decline; d) A component of BC Gas' earnings, principally earnings from Trans Mountain 's US pipeline and the Express System, are denominated in US dollars. As a result, an annual decline of $0.10 in the price of a US dollar in Canadian dollars would be expected to result in a decrease in annual consolidated net earnings of approximately C$1 million; e) Challenging economic condition which may impact demand for products and services, peer-group valuation, access to capital and share trading liquidity.

An analyst has visited the issuer's head office in Vancouver. No payment or reimbursement was received from the issuer for the related travel costs.

IMPORTANT DISCLOSURES

Distribution of Ratings

Global Stock Ratings Distribution
(as of January 7, 2005)

	Coverage Universe	
Rating	**#**	**%**
Buy	127	41.9%
Speculative Buy	51	16.8%
Hold	97	32.0%
Sell	28	9.2%
Total	303	100.0%

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SELL: The stock is expected to generate negative risk-adjusted returns during the next 12 months.

Risk Qualifier:

SPECULATIVE: Stocks bear significantly higher risk that typically cannot be valued by normal fundamental criteria. Investments in the stock may result in material loss.

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Company	Disclosure
Terasen Inc.	None

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Terasen Inc.

(TER : TSX : CAD$29.34 | Issued 105.0M)

HOLD | Target price: CAD$28.00

Bob Hastings
(604) 643-0177
bob_hastings@canaccord.com
Juan Plessis
(604) 643-0181
juan_plessis@canaccord.com

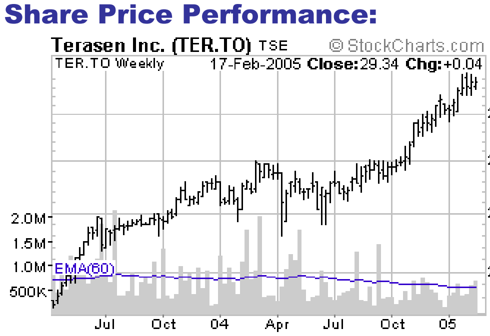
Company Statistics:

Recommendation:	**HOLD**
12-month target price:	$28.00
Price:	$29.34
52 Week Range:	$21.50-29.91
Avg. Daily Vol. (000):	255.4
Market Capitalization (M):	$3,074.8
Shares Out. (M) basic:	105.0
Current Dividend Yield:	3.1%
Current Dividend/Share:	$0.90
Bk Value/Shr:	$13.54

Earnings Summary:

FYE Dec	2003	2004	2005E	2006E
EPS:	$1.32	$1.40	$1.50	$1.60
P/E:	22.2x	21.0x	19.6x	18.3x
CFPS:	$2.75	$2.83	$2.95	$3.05
P/CF:	10.7x	10.4x	9.9x	9.6x

Share Price Performance:



Company Description:

Terasen provides energy and utility services in western Canada and the US Pacific Northwest through two regulated business segments. The Natural Gas Distribution business includes transmission and distribution of natural gas to customers in BC and provides transportation services through the pipeline. The Petroleum Transportation business transports oil and refined products from Alberta to BC and delivers crude oil to refineries in the US.

All amounts in CAD unless otherwise noted.

7.1% DIVIDEND INCREASE

Event: Terasen reported fourth quarter and full year results that were in line with expectations. The company also raised its annual dividend by 7.1% to $0.90/share.

Impact: Mildly positive.

Valuation: We are maintaining our HOLD rating and $28.00 target price on the shares of Terasen Inc. Our target price is derived from a combination of valuation metrics that include earnings and dividend yields relative to long term interest rates, dividend discount models, and earnings and cash flow multiples relative both to historical valuation and its utility and pipeline peers.

Summary

Terasen reported fourth quarter recurring income of $0.51 per share versus $0.54 last year. The company reported full year recurring EPS of $1.40 versus $1.32, in line with our $1.40 estimate. In the fourth quarter, the company instituted an accounting change to the way it records utility income tax expense, making the comparison to expected fourth quarter EPS difficult. However, the accounting change does not impact full year earnings, implying fourth quarter earnings were in-line with our estimate. The accounting change does, however, have the effect of reducing more dramatic swings from seasonality, with lower first and fourth quarter earnings and reduced losses in the second and third quarters. The company also announced a 7.1% increase to its annual dividend to $0.90 from $0.84 per share and moved its traditional increase from Q2 to Q1, effectively boosting the year over year cash dividend by 9.1%. For details on the fourth quarter and the full year, please refer to Figures 1 and 2.

Outlook

The company reiterated its 2005 EPS growth target of 6%, suggesting earnings consistent with our $1.50 estimate. Earnings will benefit from a full year of incremental 27,000 barrels/day of capacity at Trans Mountain mainline (in-service October 1, 2004), a 108,000 barrels/day capacity expansion at Express Pipeline (expected in service April 1, 2005) and continued customer growth at its natural gas distribution service areas. The company is not without its challenges however, given a 12 basis point reduction in Terasen Gas' allowed ROE to 9.03% in 2005 and lower first quarter 2005 volumes on Trans Mountain due to refinery customer turnarounds and the recent fire at Suncor's oilsands plant. We are leaving our 2005 and 2006 EPS estimates unchanged at $1.50 and $1.60, respectively.

Issues

- BC Utilities Commission approve Terasen Gas Vancouver Island's proposal of a $106 million LNG storage facility near Nanaimo.
    - The approval is subject to:
        - A long-term transportation agreement with BC Hydro
        - Engineering, procurement & construction below 110% of $75.9 million estimate
        - Construction to begin by December 31, 2005
    - Planned in-service for 2007/2008 winter period
- Mark to market gain of $3.3 million or $0.02 per share for the year in Clean Energy and recorded in "other"
- Pipeline expansions
    - 27,000 barrels/day Trans Mountain expansion in service October 1, 2004
    - 108,000 barrels/day, $110 million Express expansion by April 01, 2005 (on-time & under budget)
    - TMX (potential doubling of Trans Mountain capacity line in three phases)
        - Open season for first phase could be mid-2005
- 2005 capex of $350 million versus $154 million in 2004
    - $240 million in Natural Gas Distribution
        - $50 million to unwind leases at Coastal facilities and bring into rate base
        - $23 million on LNG storage facility

- $50 million in Petroleum Transportation
  - $12 million on TMX project development
  - $7 million Corridor de-bottlenecking
- $50 million in Water and Utility Services
  - $10-20 million potential acquisitions
- $10 million in Other

Figure 1: Terasen Inc. fourth quarter financial details

	Fourth Quarter 2003	Fourth Quarter 2004	Favourable/ (Unfavourable)	
Net Earnings (Loss): (mlns)				
Natural gas distribution				
Terasen Gas	$37.5	$36.2	(3%)	Change in allocating tax expense in quarter causes restatement of 4Q03 earnings: no impact to full year results.
Terasen Gas Vancouver Island	$7.3	$6.4	(12%)	Lower allowed ROE and no sharing mechanism in 2004.
	$44.8	$42.6	(5%)	
Petroleum transportation				
Trans Mountain	$10.0	$11.2	12%	
Corridor	$4.0	$3.8	(5%)	
Express System	$3.9	$4.9	26%	Higher throughput and 2003 earnings impacted by F/X loss.
	$17.9	$19.9	11%	
Water & Utility Services	$0.4	$0.7	75%	First and fourth quarters typically generate lower revenue & earnings.
Other businesses	($7.0)	($9.3)	(33%)	Includes $1 mln mark to market hedging loss at Clean Energy.
Total Recurring Income	**$56.1**	**$53.2**	(5%)	
Non-recurring items	($5.2)	$0.0	n.m.	
Net Income	$50.9	$53.2	5%	
Net Earnings (Loss) Per Share:				
Natural gas distribution				
Terasen Gas	$0.36	$0.34	4%	
Terasen Gas Vancouver Island	$0.07	$0.06	13%	
	$0.43	**$0.41**	6%	
Petroleum transportation				
Trans Mountain	$0.10	$0.11	11%	
Corridor	$0.04	$0.04	(6%)	
Express System	$0.04	$0.05	25%	
	$0.17	**$0.19**	10%	
Water & Utility Services	$0.00	$0.01		
Other businesses	($0.07)	($0.09)	(32%)	
Reported EPS before unusual items	**$0.54**	**$0.51**	5%	New accounting change allocating taxes distorts 4Q EPS. Full year in-line with expectations.
Unusual items	(0.05)	-	n.m.	
Reported EPS after unusual items	**$0.49**	**$0.51**	(5%)	
Average Shares O/S (mlns)	104.1	105.0	(1%)	Stock split effective June 2004.
Book Value	$13.02	$13.54	4%	
Number of Gas Customers	859,183	875,166	2%	
Gas Volumes (petajoules)				
Sales	43.9	41.4	-6%	
Transportation	20.2	19.6	-3%	
Throughput under fixed-price contracts	4.0	5.5	38%	
Total	68.1	66.5	-2%	
Oil Pipeline Deliveries (bbls/day)				
Canadian mainline	160,907	129,200	-20%	
US mainline	57,567	89,300	55%	Strong volumes in higher margin area; up 2.8% from Q3.
Express System[1]	173,871	175,400	1%	
Total	392,345	393,900	0%	

Source: Canaccord Research

Figure 2: Terasen Inc. 2004 full year financial details

	Full Year 2003	Full Year 2004	Favourable/ (Unfavourable)
Net Earnings (Loss): (mlns)			
Natural gas distribution			
Terasen Gas	$72.6	$69.7	(4%)
Terasen Gas Vancouver Island	$25.1	$26.2	4%
	$97.7	$95.9	(2%)
Petroleum transportation			
Trans Mountain	35.8	39.4	10%
Corridor	10.7	15.6	46%
Express System	9.7	15.9	64%
	56.2	70.9	26%
Water & Utility Services	$4.1	$6.6	61%
Other businesses	($21.2)	($23.6)	11%
Total Recurring Income	**$136.8**	**$149.8**	9%
Non-recurring items	($4.1)	$0.0	n.m.
Net Income	$132.7	$149.8	(13%)
Net Earnings (Loss) Per Share:			
Natural gas distribution			
Terasen Gas	$0.70	$0.67	(5%)
Terasen Gas Vancouver Island	$0.24	$0.25	3%
	$0.94	$0.92	(3%)
Petroleum transportation			
Trans Mountain	$0.34	$0.38	9%
Corridor	$0.10	$0.15	n.m.
Express System	$0.09	$0.15	n.m.
	$0.54	$0.68	25%
Water & Utility Services	$0.04	$0.06	
Other businesses	($0.20)	($0.23)	10%
Reported EPS before unusual items	**$1.32**	**$1.43**	9%
Unusual items	($0.04)	$0.00	(100%)
Reported EPS after unusual items	**$1.28**	**$1.43**	12%
Average Shares O/S (mlns)	103.8	104.7	1%
Gas Volumes (petajoules)			
Sales	125.6	121.6	(3%)
Transportation	62.3	72	16%
Throughput under fixed-price contracts	22.5	17.5	(22%)
Total	210.4	211.1	0%
Oil Pipeline Deliveries (bbls/day)			
Canadian mainline	161,500	144,400	(11%)
US mainline	54,600	91,700	68%
Express System	171,200	175,300	2%
Total	387,300	411,400	6%

Integration of Terasen Gas & TGVI achieves operating efficiencies. Partly offset by lower allowed ROE and absence of sharing mechanism.

BCUC approves construction of $100 mln LNG storage facility subject to transportation agreement with BC Hydro.

Increased throughput.

Contribution for full year; expansion expected to be completed in April/05.

Driven by organic and acquisition growth.

Includes $3.3 mln mark to market hedging gain in Clean Energy.

6% EPS growth target.

Increases dividend 7.1% to $0.90/share.

Source: Canaccord Research

Investment risks

Some of the specific risk factors that pertain to the projected six to 12 month stock price target for Terasen are as follows: a) Terasen could be exposed to significant operational disruptions and environmental liability in the event of a petroleum product spill or an accident involving natural gas; b) The unprecedented increase in the market price of natural gas in 2000 significantly eroded the competitive advantage of natural gas relative to alternative sources of energy, notably electricity, in British Columbia; c) Terasen's earnings are sensitive to interest rates in several ways. Some outstanding debt has net exposure to short-term interest rates, and is not subject to regulatory interest deferral accounts. In addition, the allowed returns on equity for BC Gas Utility, Centra Gas and Corridor are determined by formulae that result in lower allowed ROEs if long-term Canada bond yields decline; d) A component of BC Gas' earnings, principally earnings from Trans Mountain 's U.S. pipeline and the Express System, are denominated in U.S. dollars. As a result, an annual decline of $0.10 in the price of a U.S. dollar in Canadian dollars would be expected to result in a decrease in annual consolidated net earnings of approximately C$1 million; e) Challenging economic condition which may impact demand for products and services, peer-group valuation, access to capital and share trading liquidity.

An analyst has visited the issuer's head office in Vancouver. No payment or reimbursement was received from the issuer for the related travel costs.

IMPORTANT DISCLOSURES

Distribution of Ratings

Global Stock Ratings Distribution
(as of February 9, 2005)

	Coverage Universe	
Rating	**#**	**%**
Buy	124	39.0%
Speculative Buy	56	17.6%
Hold	111	34.9%
Sell	27	8.5%
Total	318	100.0%

Canaccord Ratings System:

BUY: The stock is expected to generate risk-adjusted returns of over 10% during the next 12 months.
HOLD: The stock is expected to generate risk-adjusted returns of 0-10% during the next 12 months.
SELL: The stock is expected to generate negative risk-adjusted returns during the next 12 months.

Risk Qualifier:

SPECULATIVE: Stocks bear significantly higher risk that typically cannot be valued by normal fundamental criteria. Investments in the stock may result in material loss.

Canaccord Research Disclosures as of February 18, 2005

Company	Disclosure
Terasen Inc.	None

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Terasen Inc.

(TER : TSX : CAD$26.84 | Issued 104.8M)

HOLD | Target price: CAD$28.00

Bob Hastings
(604) 643-0177
bob_hastings@canaccord.com
Juan Plessis
(604) 643-0181
juan_plessis@canaccord.com

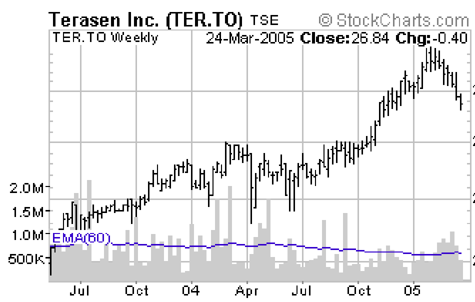
Company Statistics:

Recommendation:	**HOLD**
12-month target price:	$28.00
Price:	$26.84
52 Week Range:	$21.50-29.91
Avg. Daily Vol. (000):	45.4
Market Capitalization (M):	$3,075.9
Shares Out. (M) basic:	104.8
Current Dividend Yield:	3.1%
Current Dividend/Share:	$0.84
Bk Value/Shr:	$13.06

Earnings Summary:

FYE Dec	2004A	2005E	2006E
EPS:	$1.40	$1.50	$1.60
P/E:	19.2X	17.9X	16.8X
CFPS:	$2.90	$2.95	$3.05
P/CF:	9.3x	9.1x	8.8x

Share Price Performance:



Company Description:

Terasen provides energy and utility services in western Canada and the U.S. Pacific Northwest through two regulated business segments. The Natural Gas Distribution business includes transmission and distribution of natural gas to customers in BC and provides transportation services through the pipeline. The Petroleum Transportation business transports oil and refined products from Alberta to BC and delivers crude oil to refineries in the U.S.

All amounts in CAD unless otherwise noted.

OIL THROUGHPUT FORECAST

Event: Terasen filed an updated oil throughput forecast for Trans Mountain Pipe with the National Energy Board (NEB) last week. The company continues to see high demand supporting expansion, with a poor first quarter in 2005 due to refinery downtime. Regardless, the company has a need for new pipeline facilities to the west coast as it has received solid expressions of interest from shippers.

Impact: The negative earnings impact from the lower first quarter volumes might be around $0.10 in the first quarter. However, there should be little impact on the stock as the company had announced in its fourth quarter conference call that first quarter volumes would be low and that it still expected to achieve its 6% targeted earnings growth. In addition, the demand for long-term throughput is increasing and a new round of expansion is coming.

Valuation: We are maintaining our HOLD rating and $28.00 target price on the shares of Terasen. Our target price is derived from a combination of valuation metrics which include earnings and dividend yields relative to long term interest rates, dividend discount models, and earnings and cash flow multiples relative both to historical valuation and its utility and pipeline peers.

Summary

In its Priority Access Application filed with the NEB, Terasen gave an update on its first quarter oil throughput volumes. In the application, it appears first quarter volumes might be just over 150,000 barrels/day versus 239,100 barrels/day in the fourth quarter and 240,400 barrels/day in the first quarter last year.

The volumes are low due to refinery issues in the first quarter that are temporary in nature. Consequently, there should be no continuing impact on volumes or on Terasen's earnings longer term. The impact in the first quarter could be around $0.10 per share, at the high end of our expectations.

While this may modestly impact our earnings estimate for the year, we will not be revising our earnings until we see how well Terasen's other operations are performing, as it appears that the company is having good performance generally. Given this is a temporary situation beyond the company's control and that producers have expressed an interest for further expansion that should continue to see solid long-term earnings growth for the company, we do not expect the lower volumes to impact the stock.

Of greater importance to the stock are both the direction of long-term interest rates and the general stock market. We have assumed somewhat higher interest rates in our target price forecast, with the risk being that interest rates jump more than 50 basis points on the long end. As for the direction of the stock market, utilities normally are viewed as being somewhat defensive in a declining market, declining by less than the overall market. However, they do decline. We remain firm on our $28.00 target price and will watch for any significant price weakness for a buying opportunity.

Investment risks

Some of the specific risk factors that pertain to the projected six to 12 month stock price target for Terasen are as follows: a) Terasen could be exposed to significant operational disruptions and environmental liability in the event of a petroleum product spill or an accident involving natural gas; b) The unprecedented increase in the market price of natural gas in 2000 significantly eroded the competitive advantage of natural gas relative to alternative sources of energy, notably electricity, in British Columbia; c) Terasen's earnings are sensitive to interest rates in several ways. Some outstanding debt has net exposure to short-term interest rates, and is not subject to regulatory interest deferral accounts. In addition, the allowed returns on equity for BC Gas Utility, Centra Gas and Corridor are determined by formulae that result in lower allowed ROEs if long-term Canada bond yields decline; d) A component of BC Gas' earnings, principally earnings from Trans Mountain 's US pipeline and the Express System, are denominated in US dollars. As a result, an annual decline of $0.10 in the price of a US dollar in Canadian dollars would be expected to result in a decrease in annual consolidated net earnings of approximately C$1 million; e) Challenging economic condition which may impact demand for products and services, peer-group valuation, access to capital and share trading liquidity.

An analyst has visited the issuer's head office in Vancouver. No payment or reimbursement was received from the issuer for the related travel costs.

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Global Stock Ratings Distribution
(as of March 7, 2005)

	Coverage Universe	
Rating	**#**	**%**
Buy	116	35.9%
Speculative Buy	55	17.0%
Hold	121	37.5%
Sell	31	9.6%
	323	100.0%

Canaccord Ratings System:

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Risk Qualifier:

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Terasen Inc.

(TER : TSX : C$27.45 | Issued 105.3M)

HOLD | Target price: C$28.00

Bob Hastings
(604) 643-0177
bob_hastings@canaccord.com
Juan Plessis
(604) 643-0181
juan_plessis@canaccord.com

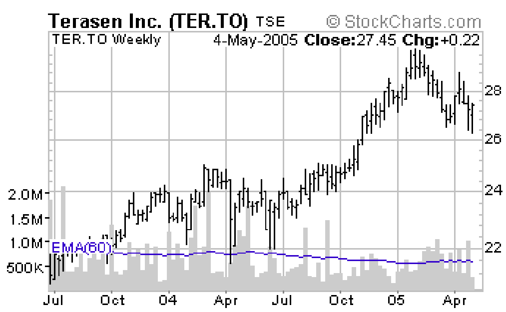
Company Statistics:

Recommendation:	**HOLD**
12-month target price:	C$28.00
52-week Range:	C$22.00-C$29.91
Market Capitalization (M):	C$2,890.5
Price:	C$27.45
Shares Out. (M) basic:	105.3
Current Dividend Yield:	3.3%
Current Dividend/Share:	C$0.90

Earnings Summary:

FYE Dec	2004A	2005E	2006E
EPS:	$1.40	$1.50	$1.60
P/E:	19.6x	18.3x	17.2x
CFPS:	$2.83	$3.03	$3.13
P/CF:	9.7x	9.1x	8.8x

Share Price Performance:



Company Description:

Terasen provides energy and utility services in western Canada and the U.S. Pacific Northwest through two regulated business segments. The Natural Gas Distribution business includes transmission and distribution of natural gas to customers in BC and provides transportation services through the pipeline. The Petroleum Transportation business transports oil and refined products from Alberta to BC and delivers crude oil to refineries in the U.S.

All amounts in C$ unless otherwise noted.

STEADY AS SHE GOES

Event: Terasen reported first quarter results that were in line with expectations.

Impact: None

Valuation: We are maintaining our HOLD rating and $28.00 target price on the shares of Terasen Inc. Our target price is derived from a combination of valuation metrics that include earnings and dividend yields relative to long term interest rates, dividend discount models, and earnings and cash flow multiples relative both to historical valuation and its utility and pipeline peers.

Summary

Terasen reported first quarter recurring income of $0.63 per share versus $0.65 last year and in line with the $0.64 consensus estimate. As expected, volume throughput on the Trans Mountain pipeline declined in the first quarter due to refinery turnarounds and oil production outages at the Alberta oil sands. Volumes on the Express System were also lower due to refinery outages. Income from natural gas distribution increased slightly as operating efficiencies, lower interest and effective tax rates offset the impact of a lower allowed return on equity. For additional details on the first quarter results, please see Figures 1 and 2.

Outlook

The company is nothing if not consistent. During its quarterly conference call, Terasen once again reiterated its 2005 EPS growth target of 6%, which implies earnings consistent with our $1.50 estimate. Earnings growth will stem from 27,000 barrels/day of incremental capacity at Trans Mountain (October 1, 2004), 108,000 barrels/day of capacity expansion at Express Pipeline (April 19, 2005), and customer growth in its natural gas distribution franchise area (about 1.8% annual growth). This growth will help offset the challenge of a 12 basis point reduction in ROE at Terasen Gas this year. We are making no changes to our 2005 and 2006 EPS estimates of $1.50 and $1.60, respectively.

Issues

- Company maintains guidance of 6% EPS growth in 2005
- Change in accounting for Clean Energy
    - Moved to an equity basis from a proportional consolidation basis
- Mark to market gain of $2.6 million or $0.02 per share for Clean Energy and recorded in "other"
- Business Development
    - Express expansion completed April 19, 2005
        - US $100 million, 10% under budget
        - Added 108,000 bbls/day of throughput capacity
    - Vancouver Island LNG storage facility - $100 million
        - Currently working with BC Hydro to obtain a Transportation Service Agreement to serve the Duke Power Point project
    - Corridor Expansion - Costs Escalating
        - Phase I increases capacity by 35,000 bbls/day
            - $8.4 million, was $6.5 million
            - In-service in the fall of 2005
        - Phase II currently under review
            - Potential expansion of 110,000 bbls/day
            - Expected in-service date of 2009
            - Estimated cost of $700-800 million, was $500-600 million in annual report, a 33-40% increase
    - TMX Expansion (potential doubling of Trans Mountain capacity line in three phases)
        - Have received support from customers through a non-binding expression of interest process
- Paid $49.4 million in January 2005 to BCG Coastal Facilities Trust to unwind synthetic lease and bring Coastal Facilities assets into rate base beginning 2005

Figure 1: Terasen first quarter income statement and capital structure

	First Quarter 2004	First Quarter 2005	Favourable / (Unfavourable)	
Revenues				
Natural gas distribution	551.5	570.2	3%	
Petroleum transportation	55.8	45.9	(18%)	
Water and utility services	34.2	42.7	25%	Strong growth at Terasen Waterworks and addition of Fairbanks Sewer and Water
Other activities	7.2	8.5	18%	$2.6 mln vs $1.6 mln mark to market gains of Clean Energy ownership; now accounting for Clean Energy on equity basis.
	648.7	667.3	3%	
Expenses				
Cost of natural gas	(351.9)	(372.1)	6%	
Cost of revenues from water and utility services	(27.7)	(31.3)	13%	
Operation and maintenance	(74.0)	(74.1)	0%	
Depreciation and amortization	(36.0)	(36.9)	2%	
Property and other taxes	(18.1)	(18.0)	(1%)	
	(507.7)	(532.4)	5%	
Operating Income	**141.0**	**134.9**	(4%)	
Financing costs	(45.1)	(45.3)	0%	
EBIT	95.9	89.6	(7%)	
Share of earnings of Express Sytem	3.8	3.4	(11%)	Impacted by temporary oil sands outages
EBT	99.7	93.0	(7%)	
Income taxes	(31.8)	(26.7)	(16%)	
Net earnings	67.9	66.3	(2%)	

Capital Structure	**Mar. 31, 2005**		
Long Term Debt	$2,023	57%	
Capital Securities	$125	4%	
Shareholder's Equity	$1,419	40%	Maintains strong balance sheet; up from 37% in Q1/04
Total Capital	$3,566	100%	

Source: Canaccord Capital

Figure 2: Terasen first quarter earnings per share and supplemental information

Net Earnings (Loss) Per Share:				
Natural gas distribution				
Terasen Gas	$0.46	$0.47	(1%)	Lower ROE offset by lower effective tax rate and reduced financing costs
Terasen Gas Vancouver Island	$0.06	$0.06	1%	
	$0.52	**$0.53**	(1%)	
Petroleum transportation				
Trans Mountain	$0.10	$0.05	(49%)	Alberta oil sands production outages and refinery turnarounds reduced throughput
Corridor	$0.04	$0.03	n.m.	
Express System	$0.04	$0.04	n.m.	$100 mln expansion completed in April/05
	$0.18	**$0.12**	(31%)	
Water and utility services	$0.00	$0.01		
Other businesses	($0.05)	($0.03)	44%	
Reported EPS before unusual items	**$0.65**	**$0.63**	3%	
Unusual items	-	-	n.m.	Slightly below 64¢ consensus estimate; on track to achieve our $1.50 estimate
Reported EPS after unusual items	**$0.65**	**$0.63**	3%	
Average Shares O/S (mlns)	104.4	105.3	(1%)	Per share numbers adjusted for June 2004 stock split
Book Value	$13.15	$13.47	2%	
Number of Gas Customers	862,631	878,560	2%	3,394 new customers added in Q1
Gas Volumes (petajoules)				
Sales	49.3	48.8	(1%)	
Transportation	21.9	21.6	(1%)	
Throughput under fixed-price contracts	4.2	4.7	12%	
Total	75.4	75.1	(0%)	
Oil Pipeline Deliveries (bbls/day)				
Canadian mainline	147,100	125,500	(15%)	Refinery outages in Q1; back to full throughput in Q2 (May nominations were > 60% above capacity)
US mainline	93,300	44,500	(52%)	
Express System	171,300	166,900	(3%)	
Total	411,700	336,900	(18%)	

Source: Canaccord Capital

Investment risks

Some of the specific risk factors that pertain to the projected 6-12 month stock price target for Terasen are as follows: 1) Terasen could be exposed to significant operational disruptions and environmental liability in the event of a petroleum product spill, an accident involving natural gas or problems with their water and sewer distribution systems; 2) The unprecedented increase in the market price of natural gas in 2000 significantly eroded the competitive advantage of natural gas relative to alternative sources of energy, notably electricity, in British Columbia; 3) Terasen's earnings are sensitive to interest rates in several ways; Some outstanding debt has net exposure to short-term interest rates, and is not subject to regulatory interest deferral accounts; In addition, the allowed returns on equity for Terasen Gas, Terasen Gas Vancouver Island and Corridor are determined by formulae that result in lower allowed ROEs if long-term Canada bond yields decline; 4) A component of Terasen's earnings, principally earnings from Trans Mountain's U.S. pipeline and the Express System, are denominated in US dollars. As a result, an annual decline of $0.10 in the price of a US dollar in Canadian dollars would be expected to result in a decrease in annual consolidated net earnings of approximately C$1.1 million; 5) Challenging economic condition which may impact demand for products and services, peer-group valuation, access to capital and share trading liquidity.

An analyst has visited the issuer's head office in Vancouver. No payment or reimbursement was received from the issuer for the related travel costs.

IMPORTANT DISCLOSURES

Distribution of Ratings

Global Stock Ratings Distribution
(as of April 8, 2005)

	Coverage Universe	
Rating	**#**	**%**
Buy	130	38.2%
Speculative Buy	56	16.5%
Hold	119	35.0%
Sell	35	10.3%
	340	100.0%

Canaccord Ratings System:

BUY: The stock is expected to generate risk-adjusted returns of over 10% during the next 12 months.
HOLD: The stock is expected to generate risk-adjusted returns of 0-10% during the next 12 months.
SELL: The stock is expected to generate negative risk-adjusted returns during the next 12 months.

Risk Qualifier:

SPECULATIVE: Stocks bear significantly higher risk that typically cannot be valued by normal fundamental criteria. Investments in the stock may result in material loss.

Canaccord Research Disclosures as of May 5, 2005

Company	Disclosure
Terasen Inc.	None

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CANACCORD CAPITAL

July 13, 2005

Terasen Inc.

(TER : TSX : C$30.08 | Issued 105.0M)

HOLD | Target price: C$29.00

Bob Hastings
(604) 643-0177
bob_hastings@canaccord.com
Juan Plessis
(604) 643-0181
juan_plessis@canaccord.com

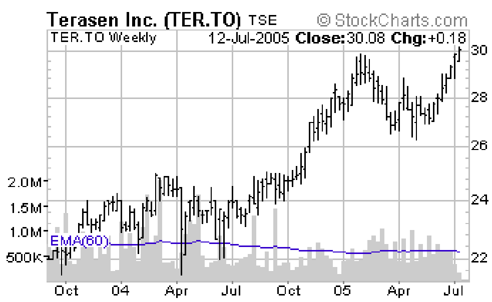
Company Statistics:

Recommendation:	**HOLD**
12-month target price:	C$29.00
52-week Range:	C$23.07-29.91
Market Capitalization (M):	C$3,158.4
Price:	C$30.08
Avg. Daily Vol. (000):	122.6
Shares Out. (M) basic:	105.0
Current Dividend Yield:	2.8%
Current Dividend/Share:	C$0.84

Earnings Summary:

FYE Dec	2004A	2005E	2006E
EPS:	$1.40	$1.50	$1.55
P/E:	21.5x	20.1x	19.4x
CFPS:	$2.83	$3.03	$3.08
P/CF:	10.6x	9.9x	9.8x

Share Price Performance:



Company Description:

Terasen provides energy and utility services in western Canada and the U.S. Pacific Northwest through two regulated business segments. The Natural Gas Distribution business includes transmission and distribution of natural gas to customers in BC and provides transportation services through the pipeline. The Petroleum Transportation business transports oil and refined products from Alberta to BC and delivers crude oil to refineries in the U.S.

All amounts in C$ unless otherwise noted.

FILES TMX EXPANSION APPLICATION WITH NEB

Event: Terasen announced that it has filed with the National Energy Board (NEB) an application to expand the capacity of the Trans Mountain pipeline system.

Impact: Mildly positive.

Valuation: We are maintaining our HOLD rating and $29.00 target price on the shares of Terasen Inc. Our target price is derived from a combination of valuation metrics which include earnings and dividend yields relative to long term interest rates, dividend discount models, and earnings and cash flow multiples relative both to historical valuation and its utility and pipeline peers.

Summary

Terasen announced that it has filed an application with the NEB to increase the capacity of its Trans Mountain crude oil pipeline system by 35,000 barrels per day to 260,000 barrels per day. The filing was expected as the company had announced shipper support earlier this year. Earnings potential from this expansion, if approved, could be around a nickel per share annually of which a portion may potentially be realized in 2006 if Terasen and shippers agree on toll stability. We view this news as a longer-term positive for Terasen. The project is expected to cost $210 million dollars and be in-service in the first quarter of 2007 pending regulatory approval. The expansion will involve building new and upgrading existing pump stations along the pipeline between Edmonton, Alberta and Burnaby, BC. This is the first phase of expansion for the Trans Mountain pipeline system and sets the stage for future pipeline expansion including the construction of a 30" pipeline loop between Hinton, Alberta and Valemount, BC, which Terasen plans to pursue later this summer.

Investment risks

Some of the specific risk factors that pertain to the projected six to 12 month stock price target for Terasen are as follows: a) Terasen could be exposed to significant operational disruptions and environmental liability in the event of a petroleum product spill or an accident involving natural gas; b) The unprecedented increase in the market price of natural gas in 2000 significantly eroded the competitive advantage of natural gas relative to alternative sources of energy, notably electricity, in British Columbia; c) Terasen's earnings are sensitive to interest rates in several ways. Some outstanding debt has net exposure to short-term interest rates, and is not subject to regulatory interest deferral accounts. In addition, the allowed returns on equity for BC Gas Utility, Centra Gas and Corridor are determined by formulae that result in lower allowed ROEs if long-term Canada bond yields decline; d) A component of BC Gas' earnings, principally earnings from Trans Mountain 's US pipeline and the Express System, are denominated in US dollars. As a result, an annual decline of $0.10 in the price of a US dollar in Canadian dollars would be expected to result in a decrease in annual consolidated net earnings of approximately C$1 million; e) Challenging economic condition which may impact demand for products and services, peer-group valuation, access to capital and share trading liquidity.

An analyst has visited the issuer's head office in Vancouver. No payment or reimbursement was received from the issuer for the related travel costs costs.

IMPORTANT DISCLOSURES

Distribution of Ratings

Global Stock Ratings Distribution
(as of July 11, 2005)

	Coverage Universe	
Rating	**#**	**%**
Buy	138	46.3%
Speculative Buy	41	13.8%
Hold	93	31.2%
Sell	26	8.7%
	298	100.0%

Canaccord Ratings System:

BUY: The stock is expected to generate risk-adjusted returns of over 10% during the next 12 months.
HOLD: The stock is expected to generate risk-adjusted returns of 0-10% during the next 12 months.
SELL: The stock is expected to generate negative risk-adjusted returns during the next 12 months.

Risk Qualifier:

SPECULATIVE: Stocks bear significantly higher risk that typically cannot be valued by normal fundamental criteria. Investments in the stock may result in material loss.

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Company	Disclosure
Terasen Inc.	None

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Terasen Inc.

(TER : TSX : C$36.00 | Issued 105.0M)

SELL ↓ | Target price: C$37.00 ↑

Bob Hastings
1 (604) 643-0177
bob_hastings@canaccord.com
Juan Plessis
1(604) 643-0181
juan_plessis@canaccord.com

Company Statistics:

Recommendation:	**SELL**
12-month target price:	C$37.00
Price:	C$36.00
52-week Range:	C$23.48-31.78
Avg. Daily Vol. (000):	119.2
Market Capitalization (M):	C$3,780.0
Shares Out. (M) basic:	105.0
Current Dividend/Share:	C$0.84
Current Dividend Yield:	2.3%

FYE Dec	2004A	2005E	2006E
EPS:	$1.40	$1.50	$1.55
P/E:	25.7x	24.0x	23.2x
CFPS:	$2.83	$3.03	$3.08
P/CF:	12.7x	11.9x	11.7x

Share Price Performance:

Company Description:

Terasen provides energy and utility services in western Canada and the US Pacific Northwest through two regulated business segments. The Natural Gas Distribution business includes transmission and distribution of natural gas to customers in BC and provides transportation services through the pipeline. The Petroleum Transportation business transports oil and refined products from Alberta to BC and delivers crude oil to refineries in the US.

All amounts in C$ unless otherwise noted.

ATTRACTIVE OFFER, TENDER

Event: Terasen and Kinder Morgan each held conference calls to discuss the announced C$6.7 billion acquisition of Terasen Inc. by Kinder Morgan Inc.

Impact: The shares of both Terasen and Kinder Morgan rose significantly on the news of the acquisition. We expect the shares of Terasen to trade at a slight discount to the implied value of the acquisition.

Valuation: We are changing our rating on the shares of Terasen Inc. from Under Review to SELL. Investors can realize about 98% of the transaction value now and avoid any regulatory approval risk and reinvest in stocks with more attractive valuations. Note that even taking the Kinder Morgan shares results in a full capital gain for tax purposes.

Summary

Terasen and Kinder Morgan Inc. held conference calls Tuesday morning to discuss the acquisition of Terasen. No material new information was provided. The prices of both company's shares gained significantly on the first day of trading since the offer was announced. We believe the offer price represents excellent value and advise investors to realize the gain immediately and reinvest in other stocks with lower valuations such as TransAlta Corporation (TA : TSX) or Emera Inc. (EMA : TSX). Quite often, investors have the opportunity to take the acquiring company's shares on a tax-free rollover basis, but this option is not available in this transaction. Consequently, investors are not materially disadvantaged by selling earlier (we assume the capital gain will be realized in the 2005 tax year, as the deal is to be approved by shareholders in October and is slated to close by year end). By selling now, investors will realize about 98% of the acquisition value and avoid any currency and non-completion risk (likely small). Note that we do not follow Kinder Morgan Inc. from an

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investment perspective and shareholders may wish to seek their own tax advice.

Clearly, some Terasen shares will be sold and the proceeds reinvested into other utility stocks, which may have helped drive up other utility stocks yesterday. In addition, there will be some speculation that other Canadian Energy Utility stocks may be acquired at a premium to the current market price. We prefer not to speculate on this outside event occurring, but doubt the likelihood of another takeover is high. The primary rationale for Kinder Morgan acquiring Terasen was to gain access to potential future expansions in Canadian oil sands production. There are limited opportunities for exposure to oil sands opportunities on the pipeline side, but include Enbridge Inc, Pembina Pipeline and Inter Pipeline Fund. Enbridge is significantly larger in size (3-4 times the enterprise value of Terasen) and all three are already trading with enterprise value multiples greater than the Terasen purchase price. Finally, while TransCanada has its eye on the oil sands with its Keystone Project, its $30 billion enterprise value ($16 billion market cap) is a bit rich for just one potential project.

Figure 1: Current Terasen Acquisition Value

	(C$/share)
Present Value of cash portion	$22.99
Value based on current KMI share price	$13.42
Present Value of first dividend	$0.2246
Present Value of second dividend	$0.2231
Current Terasen share Price	$36.00
Implied value for Terasen share	**$36.86**
Current share price premium (discount) to implied value	(2.3%)

Source: Canaccord Capital

Investment risks

Some of the specific risk factors that pertain to the projected six to 12 month stock price target for Terasen are as follows: 1) Terasen could be exposed to significant operational disruptions and environmental liability in the event of a petroleum product spill, an accident involving natural gas or problems with their water and sewer distribution systems; 2) The unprecedented increase in the market price of natural gas in 2000 significantly eroded the competitive advantage of natural gas relative to alternative sources of energy, notably electricity, in British Columbia; 3) Terasen's earnings are sensitive to interest rates in several ways; Some outstanding debt has net exposure to short-term interest rates, and is not subject to regulatory interest deferral accounts; In addition, the allowed returns on equity for Terasen Gas, Terasen Gas Vancouver Island and Corridor are determined by formulae that result in lower allowed ROEs if long-term Canada bond yields decline; 4) A component of Terasen's earnings, principally earnings from Trans Mountain's US pipeline and the Express System, are denominated in US dollars. As a result, an annual decline of $0.10 in the price of a US dollar in Canadian dollars would be expected to result in a decrease in annual consolidated net earnings of approximately C$1.1 million; 5) Challenging economic condition which may impact demand for products and services, peer-group valuation, access to capital and share trading liquidity; 6) Current valuation may depend on the success of the announced acquisition of Terasen Inc. by Kinder Morgan Inc.

An analyst has visited the issuer's head office in Vancouver. No payment or reimbursement was received from the issuer for any costs.

IMPORTANT DISCLOSURES
Price Chart*

	Date	Analyst	Rating	Target Price
1)	06/08/04	BH	Hold	24.00
2)	11/05/04	BH	Hold	26.00
3)	01/26/05	BH	Hold	28.00
4)	04/04/05	BH	Hold	26.00
5)	05/05/05	BH	Hold	28.00
6)	07/04/05	BH	Hold	29.00

* Price charts assume event 1 indicates initiation of coverage or the beginning of the measurement period.

Distribution of Ratings

Global Stock Ratings Distribution
(as of July 11, 2005)

	Coverage Universe	
Rating	**#**	**%**
Buy	138	46.3%
Speculative Buy	41	13.8%
Hold	93	31.2%
Sell	26	8.7%
	298	100.0%

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Risk Qualifier:

SPECULATIVE: Stocks bear significantly higher risk that typically cannot be valued by normal fundamental criteria. Investments in the stock may result in material loss.

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Terasen Inc.	None

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CIBC World Markets

Equity Research
Earnings Update

February 1, 2005

Pipelines, Utilities, & Power

Stock Rating:
Sector Performer

Sector Weighting:
Market Weight

12-18 mo. Price Target	$29.00
TER-TSX (1/31/05)	$29.35

Key Indices: TSXUtils

3-5-Yr. EPS Gr. Rate (E)	8.0%
52-week Range	$21.50-$29.79
Shares Outstanding	104.9M
Float	104.9M Shrs
Avg. Daily Trading Vol.	119,329
Market Capitalization	$3,078.8M
Dividend/Div Yield	$0.84 / 2.9%
Fiscal Year Ends	December
Book Value	$13.19 per Shr
2005 ROE (E)	11.0%
LT Debt	$2,642.4M
Preferred	$125.00M
Common Equity	$1,384.0M
Convertible Available	Yes

Earnings per Share	Prev	Current
2003		$1.33A
2004		$1.42E
2005		$1.55E
P/E		
2003		22.1x
2004		20.7x
2005		18.9x

Dividends per Share	
2002	$0.705
2003	$0.765
2004E	$0.825
2005E	$0.89

Debt to Total Capital	
2002	66.2%
2003	67.0%
2004E	66.5%

Company Description
Terasen is a gas distribution and oil pipeline company. Its subsidiary, Terasen Gas, distributes natural gas to B.C., including Vancouver and the interior.

www.terasen.com

Terasen Inc.

Support for Pipeline Expansion Improves Medium-Term Growth

- Terasen announced it has received strong support for the first phase of the Trans Mountain Pipeline expansion. The so-called "TMX1" is not the big prize but can contribute significantly to earnings. We are raising our target price by $1 to $29.

- Terasen has support from 17 different parties for the expansion. The support was in response to a request for expressions of interest. A formal open season will now proceed, probably this spring or early summer.

- The cost of TMX1 is about $570 million for an additional 75,000 barrels-per-day of capacity on Trans Mountain. Despite the high cost, the project is likely economic and additive to earnings on its own. It should add to earnings in 2007 and again in 2009.

- We are raising our target price because of the positive announcement and because of the lower interest rate environment boosting most utility stocks. Our rating balances the positive longer-term growth outlook against risk of renewing a major tolling agreement this year.

Stock Price Performance

Source: Reuters

All figures in Canadian dollars, unless otherwise stated.

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See "Price Target Calculation" and "Key Risks to Price Target" sections at the end of this report, where applicable.

Matthew Akman
1 (416) 956-6169
Matthew.Akman@cibc.ca

Alda Pavao, CFA
1 (416) 956-3229
Alda.Pavao@cibc.ca

Investment Conclusions

Terasen announced it has received strong support for the first phase of the Trans Mountain Pipeline expansion. The so-called "TMX1" is not the big prize but can contribute significantly to earnings. We are raising our target price by $1.

The company's proposal is to expand the 225,000 barrel-per-day Trans Mountain pipeline in three phases:

- TMX1 would expand the pipeline to 300,000 barrels-per-day by 2008 at a cost of $570 million (35,000 barrels-per-day for $205 million by early 2007 and another 40,000 barrels-per-day for $365 million by early 2009).
- TMX2 would expand the pipeline to 400,000 barrels-per-day by 2009 for an additional $900 million.
- TMX3 would expand the pipeline to 850,000 barrels-per-day by 2010 for an additional $800 million.

Terasen sought initial expressions of interest for the entire project and found support from 17 different parties. However, there was no consensus on whether TMX2 and TMX3 would head North to Prince Rupert or South to Vancouver. This uncertainty leaves open the debate of whether shippers would continue with the TMX expansion after phase 1 is complete, or whether they would instead approve Enbridge's (ENB-TSX, Sector Performer) proposed Gateway project.

But regardless, it looks like TMX1 may move forward with or without TMX2 and TMX3. A formal open season will now proceed, probably this spring or early summer. Despite the high cost, the project is likely economic and additive to earnings on its own. With a US$1.40/barrel Trans Mountain toll from Edmonton to Vancouver, the expansion could add over C$40 million revenues and sufficient earnings to generate a reasonable ROE on the $570 million investment. It should add to EPS in 2007 and again in 2009.

The positive shipper response does not necessarily mean TMX2 and TMX3 will be constructed. Enbridge recently announced plans to expand its pipeline to Chicago (the Superior to Chicago portion) by over 200,000 barrels-per day by 2008. Gateway would add another 400,000 barrels-per-day of capacity to the West Coast. So we do not think the TMX2 and TMX3 can be constructed if shippers choose Gateway instead.

While shippers weigh their options, the tolling agreement on Trans Mountain expires at the end of this year. We estimate Terasen is earning a mid 20% ROE on the pipeline vs. a National Energy Board allowed return of about 9.5%. We do not think the ROE will drop all the way to 9.5%. But we estimate that every 100 basis point reduction in that ROE is worth $0.01 - $0.02 in EPS for Terasen.

Extending the current tolling agreement and having shippers approve TMX2 and TMX3 would be a best-case scenario for Terasen. In that case, the company would be able to offset the (potentially) lower ROE on existing pipeline rate base with earnings from the expansion.

We are raising our target price by $1 because of the positive announcement and because of the lower interest rate environment boosting most utility stocks. Our target on Terasen is now based on an 18.7x multiple of forecast 2006 earnings (in line with the multiple we apply to Enbridge).

The stock has already been trading around the $29 level lately, but most of the Canadian pipelines and utilities are at or near our targets. Our Sector Performer rating balances the positive longer-term growth outlook against near-term risks surrounding the Trans Mountain tolling agreement.

Price Target Calculation

Our $29 target price is based on an 18.7x multiple of our 2006 EPS forecast of $1.55. It also implies a 3.6% dividend yield. Given Terasen's superior growth prospects and low risk profile, we are using a target P/E multiple at the higher end of the group average, but within the stock's historical trading range of 8x-20x forward earnings.

Key Risks to Price Target

Terasen could fall short of our 2005 and 2006 earnings forecasts (and fail to meet our target price) for various reasons, including (but not limited to) the lower achieved ROEs and lower-than-expected growth in oil sands volumes. Increased competition for pipeline and utility assets by financial players also raises risk to returns on possible acquisitions. In addition, the stocks are sensitive to changes in Canadian bond yields. If broader market risk dissipates and bond yields rise significantly, valuation in the sector could fall.

Our EPS estimates are shown below:

	1 Qtr.	2 Qtr.	3 Qtr.	4 Qtr.	Yearly
2003 Actual	$0.71A	$0.08A	($0.07A)	$0.61A	$1.33A
2004 Current	$0.75A	$0.10A	($0.03A)	$0.61E	$1.42E
2005 Current	--	--	--	--	$1.55E

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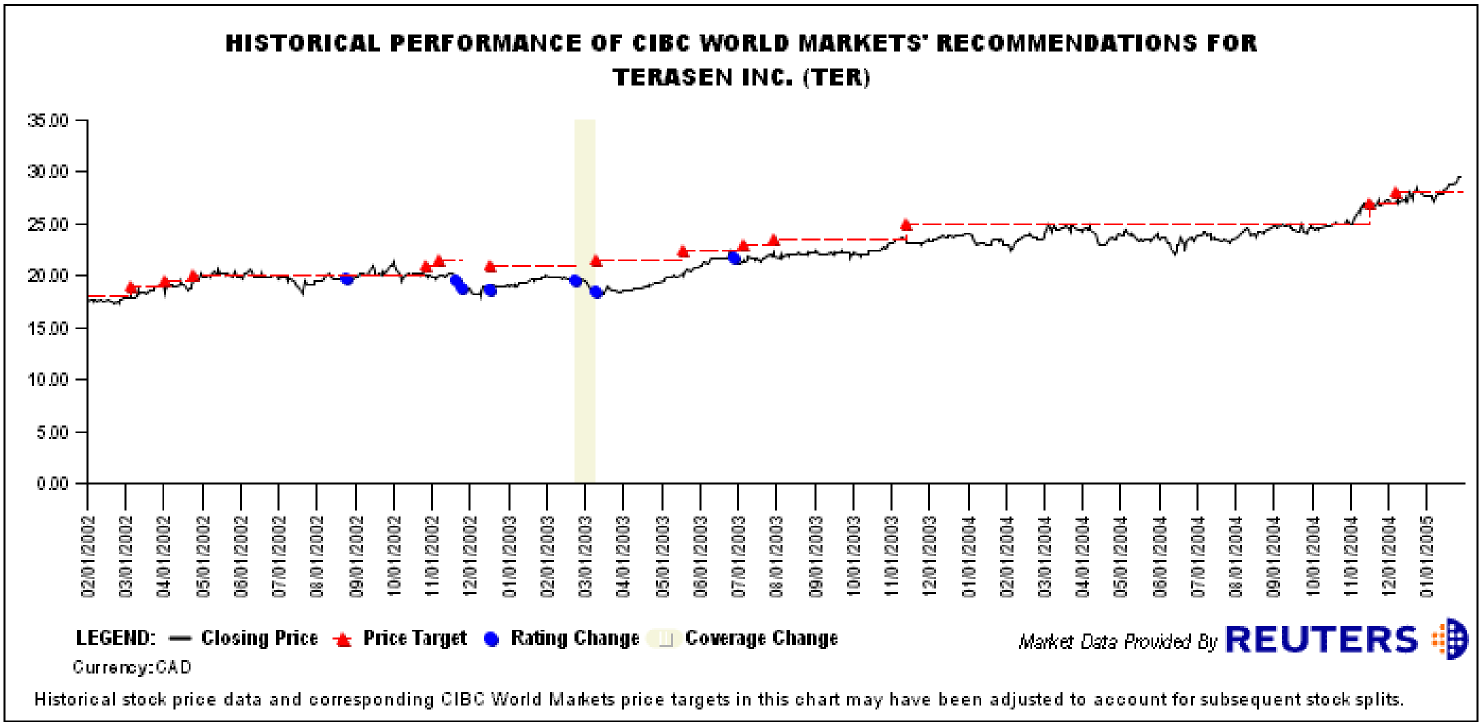
CIBC World Markets Price Chart



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Date	Change Type	Closing Price	Rating	Price Target	Coverage
03/08/2002	▲	17.81	H	19.00	Peter Case
04/03/2002	▲	18.38	H	19.50	Peter Case
04/26/2002	▲	19.58	H	20.00	Peter Case
08/26/2002	●	19.66	SU	20.00	Peter Case
10/28/2002	▲	20.10	SU	21.00	Peter Case
11/07/2002	▲	20.13	SU	21.50	Peter Case
11/21/2002	●	19.48	SP	21.50	Peter Case
11/25/2002	▲●	18.85	NR	None	Peter Case
12/18/2002	▲●	18.63	SP	21.00	Peter Case
02/24/2003	▲●□	19.51	S	None	CIBC World Markets Corp.
03/12/2003	▲●□	18.41	SO	21.50	Matthew Akman
05/21/2003	▲	20.13	SO	22.50	Matthew Akman
06/30/2003	●	21.78	SP	22.50	Matthew Akman
07/08/2003	▲	21.30	SP	23.00	Matthew Akman
08/01/2003	▲	21.93	SP	23.50	Matthew Akman
11/13/2003	▲	23.58	SP	25.00	Matthew Akman
11/15/2004	▲	27.00	SP	27.00	Matthew Akman
12/06/2004	▲	27.00	SP	28.00	Matthew Akman

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Abbreviation	Rating	Description
Stock Ratings		
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SP	Sector Performer	Stock is expected to perform in line with the sector during the next 12-18 months.
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B	Buy	Expected total return over 12 months of at least 15%.
H	Hold	Expected total return over 12 months of at least 0%-15%.
UP	Underperform	Expected negative total return over 12 months.
S	Suspended	Stock coverage is temporarily halted.
DR	Dropped	Stock coverage is discontinued.
R	Restricted	Restricted
UR	Under Review	Under Review
Sector Weightings**		
O	Overweight	Sector is expected to outperform the broader market averages.
M	Market Weight	Sector is expected to equal the performance of the broader market averages.
U	Underweight	Sector is expected to underperform the broader market averages.
NA	None	Sector rating is not applicable.

**Broader market averages refer to the S&P 500 in the U.S. and the S&P/TSX Composite in Canada.

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Sector Performer (Hold/Neutral)	406	46.8%	Sector Performer (Hold/Neutral)	233	57.4%
Sector Underperformer (Sell)	175	20.2%	Sector Underperformer (Sell)	83	47.4%
Restricted	0	0.0%	Restricted	0	0.0%

Ratings Distribution: Pipelines, Utilities, & Power Coverage Universe

(as of 31 Jan 2005)	Count	Percent	Inv. Banking Relationships	Count	Percent
Sector Outperformer (Buy)	3	30.0%	Sector Outperformer (Buy)	2	66.7%
Sector Performer (Hold/Neutral)	5	50.0%	Sector Performer (Hold/Neutral)	3	60.0%
Sector Underperformer (Sell)	2	20.0%	Sector Underperformer (Sell)	1	50.0%
Restricted	0	0.0%	Restricted	0	0.0%

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Equity Research
Earnings Update

February 18, 2005

Pipelines, Utilities, & Power

Terasen Inc.

Solid Earnings, But Slightly Lower Than Expected

Stock Rating:
Sector Performer

Sector Weighting:
Market Weight

12-18 mo. Price Target	$29.00
TER-TSX (2/17/05)	$29.34
Key Indices: TSXUtils	
3-5-Yr. EPS Gr. Rate (E)	6.0%
52-week Range	$21.50-$29.91
Shares Outstanding	104.9M
Float	104.9M Shrs
Avg. Daily Trading Vol.	94,104
Market Capitalization	$3,077.8M
Dividend/Div Yield	$0.90 / 3.1%
Fiscal Year Ends	December
Book Value	$13.04 per Shr
2005 ROE (E)	11.0%
LT Debt	$2,583.3M
Preferred	$125.00M
Common Equity	$1,371.1M
Convertible Available	Yes

Earnings per Share	**Prev**	**Current**
2004	$1.42E	$1.40A
2005	$1.55E	$1.50E
2006	$1.55E	$1.50E
P/E		
2004	20.7x	21.0x
2005	18.9x	19.6x
2006	18.9x	19.6x

Dividends per Share	
2002	$0.705
2003	$0.765
2004	$0.825
2005E	$0.90

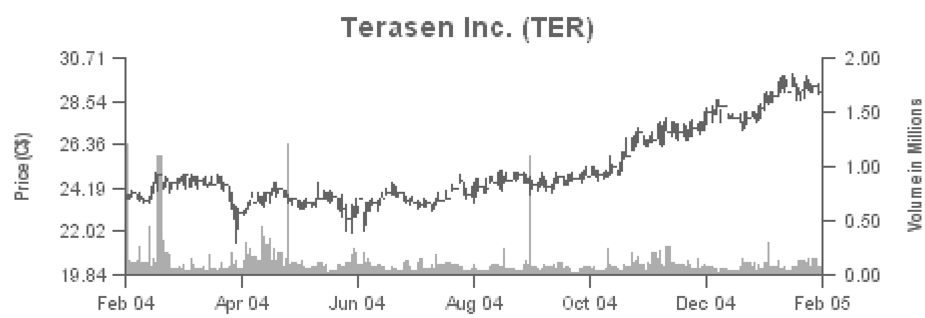
Debt to Total Capital	
2002	66.2%
2003	67.0%
2004	65.4%

Company Description
Terasen is a gas distribution and oil pipeline company. Its subsidiary, Terasen Gas, distributes natural gas to B.C., including Vancouver and the interior.

www.terasen.com

- Terasen reported normalized 2004 EPS of $1.40 vs. our estimate of $1.42 and $1.33 in 2003. A dividend increase of 7% was in line with expectations. We are reducing our estimates by $0.05, but maintaining our $29 target price.
- Gas Distribution earnings are falling due to lower allowed ROEs that move in lockstep with forecast long bond yields. A regulatory hearing in Q3 of this year could help offset this impact going forward, if the BCUC allows for a change in the ROE formula or increase in equity ratio.
- Oil Pipeline earnings remain strong, and offset the decline in Gas Distribution. We see visible growth of 6% in 2005 due to ongoing growth in the segment. However, near-term oil sands production and refinery issues cause us to slightly reduce EPS estimates.
- We are not raising our $29 target price even though the stock is already trading at that level. The TMX project is well developed and makes sense but faces stiff competition. In that context, we believe Terasen shares are fully valued.

Stock Price Performance



Source: Reuters

All figures in Canadian dollars, unless otherwise stated.

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See "Price Target Calculation" and "Key Risks to Price Target" sections at the end of this report, where applicable.

Matthew Akman
1 (416) 956-6169
Matthew.Akman@cibc.ca

Alda Pavao, CFA
1 (416) 956-3229
Alda.Pavao@cibc.ca

Investment Summary

Terasen reported normalized 2004 EPS of $1.40 vs. our estimate of $1.42 and $1.33 in 2003, and raised its dividend by 7%. Earnings from Gas Distribution were slightly weaker-than-expected. We are reducing our estimates by $0.05, but maintaining our $29 target price.

For a detailed breakdown and analysis of earnings by segment, please see the appendix to this comment.

Oil Pipeline Growth Offsets Gas Distribution Decline

Oil pipeline earnings drove solid growth again for Terasen in 2004. Volume flows on the Trans Mountain Pipeline improved by over 9% on the Canadian portion, and almost doubled on the U.S. portion. We see continued growth in 2005 as an expansion on the Express Pipeline comes into service by April.

Unfortunately, declining earnings in Gas Distribution are taking some of the upside potential out of Terasen's earnings per share. Gas Distribution earnings are falling due to lower allowed ROEs that now move in lockstep with forecast long bond yields. We estimate that every 50 basis point reduction in bond yields results in a $0.05 EPS impact.

Absent any change in the regulatory framework, Terasen Gas Distribution could experience a further drop in its earnings in 2006. The company has initiated a hearing, likely beginning in Q3, to achieve a new ROE formula and/or thicker equity ratio. However, the outcome of this hearing is uncertain, as the BC regulator has not, to date, signaled an intention to change the current formula.

In addition, management indicated volumes on the Trans Mountain pipeline would be negatively impacted in Q1'05 by refinery outages and oil sands production delays. The combined effect of the Gas Distribution ROE drop, and oil volume issues cause us to reduce our estimates by $0.05 in 2005 and 2006. Our estimate for 2005 is in line with management guidance for 6% growth off of a $1.40 EPS base.

Future Growth Depends on TMX Project

Terasen has plans for $350 million of capital spending in 2005 (internally and debt financed), and has several modest but attractive growth initiatives in the works:

- $100 million LNG plant on Vancouver Island
- Expansion of Corridor Pipeline in Alberta (2007 timeframe)
- Organic growth in the Water & Utility Services business

These initiatives provide some organic growth, but we believe the stock is trading at a premium to the group because the market anticipates a major expansion on the Trans Mountain Pipeline (TMX 1, 2 and 3). The company plans to hold an open season for TMX1 in the summer of this year.

We think the TMX expansion is a logical and viable project. Terasen has done thoughtful and detailed work on the route and on expansion of docking facilities in Vancouver. Our analysis suggests the company could move a lot more oil out of Vancouver and into the California market.

However, competition in the form of Enbridge's (ENB-TSX, Sector Performer) Gateway Project is stiff. Our view is that Enbridge's project is also viable and reflects a sound long-term vision that shippers may choose to follow. Large Chinese companies may support Enbridge, resulting in the cancellation of the TMX project. In this sense, the outcome is highly unpredictable and to some extent, out of Terasen's hands despite its good work.

Still Deserves Premium, But No Higher Than Current One

We believe Terasen shares will continue to trade at some premium to the Canadian pipeline and utility group. The company is very well managed and has some visible growth projects.

But the stock is already trading at 19.5x forward earnings estimates and the company's own guidance on the conference call. Despite the 7% dividend increase, the yield is only 3.1%, at the low end of the utility group.

Unless and until Terasen achieves further clarity on approval of the TMX expansion, we do not see the stock moving up from current levels. The stock is already trading at our $29 target but other stocks in the group are also at or through our price targets. Therefore, we are maintaining our Sector Performer rating.

Appendix: Summary of Q4 and Full Year 2004 Results

We normalized Terasen's reported Q4'04 EPS to $0.52 per share by excluding a $1.0 million (after-tax) mark-to-market loss related to natural gas hedges at Clean Energy. For the full year 2004, normalized EPS came in at $1.40 compared to $1.33 in 2003.

Exhibit 1. Segmented Earnings for Terasen

(data in C$ millions, unless otherwise stated)

	Q4/04A	Q4/03A	2004A	2003A
Terasen Gas	$36.2	$37.5	$69.7	$72.6
Terasen Gas (Vancouver Island)	$6.4	$7.3	$26.2	$26.2
Trans Mountain Pipeline	$11.2	$10.0	$39.4	$35.8
Express Pipeline System	$4.9	$3.9	$15.9	$9.7
Corridor Pipeline	$3.8	$4.0	$15.6	$10.7
Water and Utility Services	$0.7	$0.4	$6.6	$4.1
Other Activities	($6.7)	($5.5)	($20.3)	($14.6)
Capital Securities Distributions (net of tax)	($1.6)	($1.7)	($6.6)	($6.6)
Operating Earnings for Common	**$54.9**	**$55.9**	**$146.5**	**$137.9**
Unusual Items	($1.0)	($5.2)	$3.3	($5.2)
Reported Earnings	$53.9	$50.7	$149.8	$132.7
Average Shares Outstanding (mln)	104.8	104.0	104.7	103.6
Operating Earnings per Share	**$0.52**	**$0.54**	**$1.40**	**$1.33**
Reported Earnings per Share	$0.51	$0.49	$1.43	$1.28

Notes:

1. Unusual item in 2004 relates to $3.3 million gains from mark-to-market accounting on Terasen's share of Clean Energy's natural gas positions.
2. Unusual items in 2003 relate to gas utility restructuring charge ($3.4 mln after-tax) and write-down of Westport Innovations investment ($1.8 mln after-tax).

Source: Company reports and CIBC World Markets Inc.

Natural Gas Distribution

Q4 earnings from the gas distribution utilities came in lower-than-expected, mainly as a result of a change in the method of accounting for quarterly income taxes at Terasen Gas. Going forward, Terasen Gas' income taxes will be determined using an effective tax rate instead of allocating annual taxes based on budgeted quarterly sales revenues. Quarterly earnings from Terasen Gas have been restated in 2003-4 to reflect this accounting change.

For the full year, cost savings from the integration of the utility operations (+$4.1 million earnings impact) helped to mitigate some of the negative impacts from a lower allowed ROE (-$2.4 million earnings impact) and introduction of earnings sharing in 2004 (-$4.7 million impact).

Petroleum Transportation

Trans Mountain Pipeline's earnings showed solid growth in 2004, driven by strong demand from U.S. refiners for oil sands production. Volume throughput on the Canadian mainline was up 9.25% year-over-year while the U.S. portion showed very strong y/y growth (up 68%). The higher volume flows also helped to offset lower Canadian tolls.

Management cautioned that Trans Mountain volumes will be depressed in the first few months of this year due to planned refinery turnarounds and delayed oil sands production from Suncor (SU-TSX, Sector Performer) and other producers. But these refinery and oil volume issues should dissipate by Q3 at the latest and we should see resumed throughput and earnings growth from Trans Mountain.

Earnings from **Express Pipeline System** came in slightly higher-than-expected, at $15.9 million in 2004 vs. $9.7 million in 2003 and our $15 million estimate. The increase was mainly attributable to higher throughput, averaging 175,300 Bbls/d in 2004 (up 2% year-over-year) and the reversal of foreign exchange losses. The 108 MBbls/day capacity expansion on Express is on schedule to come into service by April this year, which should drive solid organic growth from Express in 2005.

A full year of operations (in service May 2003) contributed to the improved earnings from **Corridor Pipeline** in 2004 (reported $15.6 million compared to $10.7 million in 2003).

Terasen announced plans to add 35 MBbls/day of capacity on Corridor with additional pumping facilities this year. This $6.5 million expansion could be the first stage of a larger phased expansion to add 110-200 MBbls/d of incremental capacity by 2009/10.

Water and Utility Services

The $2.5 million increase in full year earnings from the Water and Utility Services segment was attributable to organic growth ($1.3 million in earnings growth) and acquisitions ($1.2 million in growth).

The company intends to grow these businesses (organically and through acquisitions) in 2005 with a capital spending plan of $50 million.

Other Activities

Excluding a $3.3 million mark-to-market gain from Clean Energy and capital securities distributions, we estimate that Other Activities contributed a loss of $20.3 million in 2004, up from $14.6 million last year. An increase in financing costs and lower income tax recovery were the main contributing factors for the higher operating losses from Other Activities.

Price Target Calculation

Our $29 target price is based on a 19.3x multiple of our 2006 EPS forecast of $1.50. It also implies a 3.3% dividend yield. Given Terasen's superior long-term growth prospects and low risk profile, we are using a target P/E multiple at the higher end of the group average, but within the stock's historical trading range of 8x-20x earnings.

Key Risks to Price Target

Terasen could fall short of our 2005 and 2006 earnings forecasts (and fail to meet our target price) for various reasons, including (but not limited to) the lower achieved ROEs and lower-than-expected growth in oil sands volumes. Increased competition for pipeline and utility assets by financial players also raises risk to returns on possible acquisitions. In addition, the stocks are sensitive to changes in Canadian long bond yields. If broader market risk dissipates and bond yields rise significantly, valuation in the sector could fall.

Our EPS estimates are shown below:

	1 Qtr.	2 Qtr.	3 Qtr.	4 Qtr.	Yearly
2004 Actual	$0.63A	$0.17A	$0.08A	$0.52A	$1.40A
2005 Prior	--	--	--	--	$1.55E
2005 Current	--	--	--	--	$1.50E
2006 Prior	--	--	--	--	$1.55E
2006 Current	--	--	--	--	$1.50E

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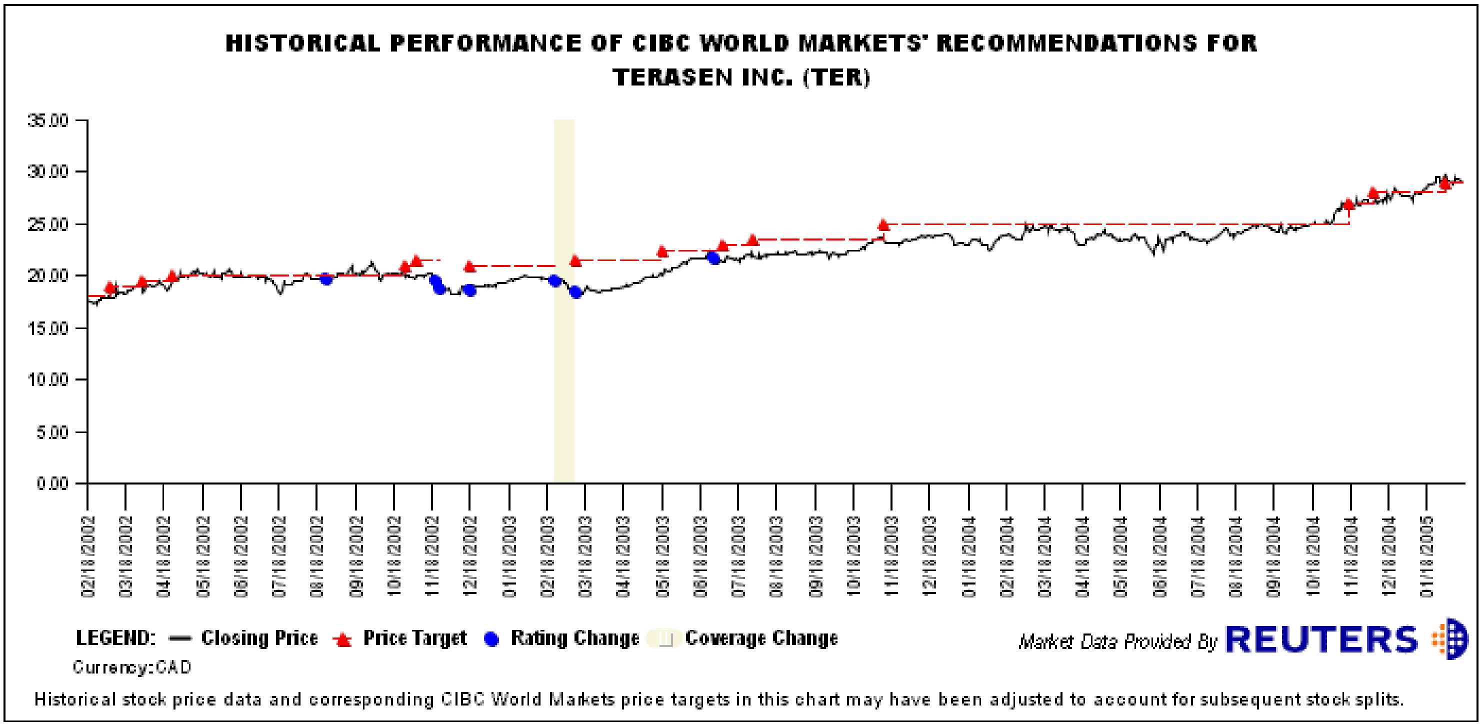

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08/26/2002	●	19.66	SU	20.00	Peter Case
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11/07/2002	▲	20.13	SU	21.50	Peter Case
11/21/2002	●	19.48	SP	21.50	Peter Case
11/25/2002	▲●	18.85	NR	None	Peter Case
12/18/2002	▲●	18.63	SP	21.00	Peter Case
02/24/2003	▲●□	19.51	S	None	CIBC World Markets Corp.
03/12/2003	▲●□	18.41	SO	21.50	Matthew Akman
05/21/2003	▲	20.13	SO	22.50	Matthew Akman
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08/01/2003	▲	21.93	SP	23.50	Matthew Akman
11/13/2003	▲	23.58	SP	25.00	Matthew Akman
11/15/2004	▲	27.00	SP	27.00	Matthew Akman
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UP	Underperform	Expected negative total return over 12 months.
S	Suspended	Stock coverage is temporarily halted.
DR	Dropped	Stock coverage is discontinued.
R	Restricted	Restricted
UR	Under Review	Under Review
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M	Market Weight	Sector is expected to equal the performance of the broader market averages.
U	Underweight	Sector is expected to underperform the broader market averages.
NA	None	Sector rating is not applicable.

**Broader market averages refer to the S&P 500 in the U.S. and the S&P/TSX Composite in Canada.
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Sector Underperformer (Sell)	165	19.4%	Sector Underperformer (Sell)	75	45.5%
Restricted	0	0.0%	Restricted	0	0.0%

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Sector Underperformer (Sell)	2	20.0%	Sector Underperformer (Sell)	1	50.0%
Restricted	0	0.0%	Restricted	0	0.0%

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Corporate Debt Comments

February 18, 2005

Joanna Zapior, CFA, CMC
(416) 594-8498
Strategy, Utilities, Real Estate, CMBS

Trevor Bateman, CFA, CA
(416) 594-7992
Banks, Non-bank financials, Autos, ABS

Kevin Yong, CFA
(416) 956-6273
Oil & Gas, Aerospace

Phillip Armstrong
(416) 956-3272
Telecom, Cable, Insurance, Retail, Consumer Products

Adam Bulley
(416) 594-8626
Associate

Dina Giacomelli
(416) 956-6056
Associate

Mark Litowitz
(416) 956- 3858
Associate

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Terasen Inc: 4Q04 results.

Mark Litowitz, 416-956-3858 on behalf of Joanna Zapior.

CREDIT IMPACT: Neutral. Fourth quarter credit metrics were better, both year-over-year and sequentially, with leverage improving by roughly 2% and 1.6% from last quarter and a year ago, respectively. Solid operating cash flows and debt reduction were the primary drivers for the improvements in credit metrics. Strong growth in annual earnings from the pipelines business more than offset weaker annual earnings from the gas distribution segment. We continue to rate this company Market Perform.

Terasen: 4Q04	Debt to CF	EBITDA to Interest	Debt to Cap at book	Debt to Cap at Mkt	Realized ROE	LTM CF	YTD FCF	Adjusted debt
4Q04	10.0	3.0	68.3%	46.1%	11.7%	296	89	2,936
4Q03	10.5	2.7	69.9%	50.4%	11.0%	289	-229	3,030
3Q04	10.4	3.0	70.3%	50.6%	12.0%	304	-23	3,053

	4Q04	4Q03	YTD 04	YTD 03
Earnings contribution:				
GAS DISTRIBUTION				
Terasen Gas	36.2	37.5	69.7	72.6
Terasen Gas VC Island	6.4	7.3	26.2	26.2
PETROLEUM TRANSP.				
TransMountain	11.2	10.0	39.4	35.8
Corridor	3.8	4.0	15.6	10.7
Express	4.9	3.9	15.9	9.7
WATER & UTILITY	0.7	0.4	6.6	4.1
OTHER	(9.3)	(8.8)	(23.6)	(23.0)
Number of gas customers	NA	NA	875,166	859,183
Gas transportation volume (in petajoules)	19.6	20.2	72	72.2
Trans Mountain Canadian Mainline (bbl/d)	239,100	218,500	236,100	216,100
Trans Mountain US Mainline, included in Canadian Mainline (bbl/d)	89,300	57,700	91,700	54,600
Express System (bbl/d)	175,400	174,000	175,300	171,200

- Earnings from Terasen Gas were weaker in 2004 compared to 2003. Lower 2004 earnings were primarily due to lower allowed ROE, which offset efficiency gains from the integration of Vancouver Island and BC mainland operations. Gas customers grew by 1.86%, with about 16,000 new customers signed up during the year.
- Strong demand for oil in both Canada and south of the border helped to increase 2004 throughput volumes on TransMountain and Express pipelines compared to 2003. The increased year-over-year throughput was the main reason for stronger earnings contribution from Petroleum Transportation in 2004 compared with 2003 pipeline earnings. A full year of earnings contribution from Corridor, which commenced operation in May 2003, also contributed to year-over-year growth in pipeline earnings.
- Water and utility services segment earnings improved by $2.5 million in 2004. Most of this growth in earnings was due to organic growth from existing water and utility services business. Another source of earnings growth in this segment came from the acquisition of Fairbanks Sewer and Water.

	Analyst	Senior unsecured DBRS	Senior unsecured Moody's	Senior unsecured S&P	Credit fundamentals (1-3 years)	Rating change probab. (1 year)	Valuation	YTD total return: Shorter bond Bond	YTD total return: Shorter bond Return	YTD total return: Longer bond Bond	YTD total return: Longer bond Return	YTD change in spread: Shorter bond Curr Sprd	YTD change in spread: Shorter bond YTD Chng	YTD change in spread: Longer bond Curr Sprd	YTD change in spread: Longer bond YTD Chng

Pipelines: *Solid, largely regulated fundamentals, though regulatory environment disadvantages those companies that have North American growth plans as Cdn leverage is higher and returns lower. Our investment thesis rests on two pillars: 1) operating excellence and cost management will be key in light of 2) regulators pressuring for cost control, including returns. Holding company risk has been increasing with expansion in non-regulated areas, equity market push for growth, and still elevated leveragex*

Gas distribution: *Stable sector, with strong operating franchises and good fundamentals. However, no standalone credits left (exceptand credit quality is affected by parent activities. See also our comment on the pipeline sector.*

Enbridge Inc	JZ	A	A3	A-	May weaken (M&A, projects)	Medium	C	5.8% 2008	0.63%	8.2% 2024	2.58%	38	▲ 2	98	▼ 3
Enbridge Pipelines	JZ	A(high)	NR	A-	Stable	Medium	R	5.621% 2007	0.48%	7.2% 2032	3.52%	33	▲ 3	121	▼ 4
Enbridge Gas Dist.	JZ	A	NR	A-	Stable	Medium	R	11.15% 2009	0.81%	6.1% 2028	2.75%	53	▲ NA	101	↔ 0
Alliance Pipe	JZ	A(low)	A3	BBB+	Strong	Very low	F	7.23% 2015	1.81%	7.217% 2025	2.04%	48	▼ 15	94	▼ 5

There is continued M&A and large project risk - lots of noise in the news as juggling for positions continues. The market now prices its uncertainty about committment to "A" ratings. Pipe acquisition in the GoM has eroded current balance sheet to the levels conti permissible under the S&P rating. Over time, we see balance sheet quality potentially weakening as more risky assets may be added while mature, stable assets end up in income trust. That it has historically been a defensive credit (low spread volatility) sible us a pause but history may not repeat itself. We view **opcos** as better credits in line with DBRS logic but not necessarily better value. Note **EGD** has a 2005 rate case. Regulatory stability has improved after a recent spate of decisions & PBR is possible. Mainline is renegotiating its settlement this fall. For **Alliance,** we like the "structuring premium" of an amortizer and the simplicity of this credit; not affected by how the ownership is structured; valuation reflects the defensive nature of this credit. It continues to perform as expected. Mgt turnover has been signficant (CFO earlier and now CEO) but this has no credit impact either for this contractually structured credit

TransCanada	JZ	A	A2	A- Neg	Stable but event risk	Medium	R	6.05% 2007	0.60%	6.5% 2030	3.64%	31	▼ 5	110	▼ 5

Neg outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand (the most recent big one of a U.S. pipeline appears to have crystallized the agency thinking in a constructive way, subject to how conservative mgt will remainik will tak financing side) . Expansion in generation (including a now more likely restart of two more Bruce units), another potential large opportunistic acquisition & large projects in the longer term are credit risks. Regulatory environment continues to be unsate) . Expansi mgt's eyes which raises questions about whether the company will want to trustify some of the lower return regulated assets - a potential negative for bondholders.

Duke (Westcoast)	JZ	A(low)	NR	BBB Pos	Improving	Low	R	5.7% 2008	0.66%	7.15% 2031	2.92%	48	▲ 2	123	↔ 0
Duke (Union Gas)	JZ	A	NR	BBB Pos	Standalone stbl + DUK effect	Low	R	5.7% 2008	0.64%	8.65% 2025	2.51%	43	▲ 2	114	↔ 0
MNEP	JZ	A	A1	A	Strong	Very low	F	NA	NA	6.9% 2019	1.45%	NA	NA	81	▲ 1

Duke took steps to turn the corner and the balance sheet repair actions have finally shown. Exit from non-core businesses continues & core regulated operations are stable. We think DENA will continue to be a source of grief for a while until markets improvtook until the new idea of contributing it to a joint venture hatches (lowering of risk). Resumed talk of opportunistic growth means that the golden age for bondholders is almost over (some upside remains from DENA cleanup & possible upgrade). We believe, in l th long run, **Union Gas's** distribution portion, as a non-core asset, is more separable from Duke than Westcoast. Its storage is a strategic asset to Duke. In the short term, Union provides solid cash flow to Duke and supports its credit quality. Spreads have performed reasonably well & are now in the middle of the utiltiy pack, leaving little further room for outperformance. For **MNEP**, we like structural protection and simplicity; valuation reflects the defensive nature of this credit.

Terasen	JZ	A(low)	A3	BBB-	Stable but some event risk	Low	C	6.3% 2008	0.89%	NA	NA	55	▼ 3	NA	NA
Terasen Gas	JZ	A	A2	BBB	Stable	Low	C	NA	NA	6.95% 2029	2.87%	NA	NA	129	↔ 0

Business fundamentals are a strong combination of a regulated gas distribution and pipelines, with aggressive financial profile determining the rating. Market pricing suggests that the market does not give full credence to the S&P rating (but still incorpoundamenta despite its now unsolicited status). Project CAPEX could be high. For **Terasen Gas**, we like the fundamentals of gas distribution at current spread, compared to historical spreads, but don't think that holdco spread can tighten much in the near term.

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February 24, 2005

Pipelines, Utilities, & Power

Sector Weighting:

Market Weight

Oil Pipelines

Enbridge And Terasen Battle For Producer Support

- On February 14 and 16, we toured Enbridge's and Terasen's competing proposals for a new $2.5 billion oil pipeline from Alberta's oil sands to the West Coast. We were impressed with the viability of both projects but concerned about the competitive dynamics behind them.
- Enbridge's Gateway Project is further advanced than we thought. Detailed route selection and community consultation are well under way. The advantage of a deep water port is likely to sway Chinese oil companies seeking long-term and reliable supply.
- But Terasen's TMX expansion into Vancouver Harbour appears doable despite tanker traffic and urban surroundings. Some domestic oil companies seeking a practical near-term and medium-term alternative to Midwest markets are sure to sign on.
- The tours left us with the impression there is no clear winner and that the companies may wind up in parallel regulatory processes. In the long term, pipeline investors should benefit from new capital investments. But patience may be tested while the process plays out.

All figures in Canadian dollars, unless otherwise stated.

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Matthew Akman
1 (416) 956-6169
Matthew.Akman@cibc.ca

Alda Pavao, CFA
1 (416) 956-3229
Alda.Pavao@cibc.ca

Investment Summary

Some of the best energy infrastructure investments have been spoiled by too much competition. Undersupplied electricity markets seemed ripe for big returns until too many power plants were built. Some interstate gas pipelines to the Northeast suffered for years until gas demand caught up with excess pipeline capacity. Are Western Canadian oil pipelines another overcapacity situation waiting to happen?

On February 14 and 16, we toured Enbridge's (ENB–TSX, Sector Performer) and Terasen's (TER–TSX, Sector Performer) competing proposals for a new $2.5 billion oil pipeline from Alberta's oil sands to the West Coast. Enbridge's Gateway project to a northern port is further advanced than we realized. And Terasen's TMX project to Vancouver is more viable than we thought. But while these projects represent some of the best organic growth opportunities the sector has to offer, we were concerned about the competitive dynamics shaping up between their proponents.

It is clearer to us now than before how oil producers stand to benefit from new oil pipelines to the West but less clear how pipeline investors will benefit. Investor excitement over new oil pipelines to the West Coast is palpable. Shares in Enbridge and Terasen have both achieved premium valuations that, in part, reflect expectations for big new investments. Yet, we see no near-term resolution of the situation. In fact, we see the potential for a drawn-out battle in front of the National Energy Board (NEB).

Enbridge's Gateway Project has, in our view, been wrongly criticized for being impractical. Construction through the Rocky Mountains has been viewed as too challenging and carrying large volumes at the outset viewed as too imprudent. We flew the proposed Gateway route by helicopter and were impressed by natural valleys and ready road access that would facilitate Enbridge's construction plans. The wide-open, deep-water port at Kitimat would accommodate growth well into the future.

At the same time, we think Terasen's project in the Vancouver Harbour has been wrongly characterized as a "Not-In-My-Backyard" protest waiting to happen. We traveled the tanker route by boat through the harbour and reviewed the Westridge Dock and oil storage facilities. Terasen has carefully worked through logistical issues that would permit a large increase in oil volumes to move by ship from Vancouver to the oil-hungry California market.

The viability of both projects and tenacity of their proponents begs the question how this competition will be resolved. Normally one of the two projects would achieve shipper support and proceed, while the other project would not achieve support and wither. But in this instance, we are not convinced that will happen.

Terasen's phased approach may allow shippers to support the first phase of Trans Mountain's expansion and Enbridge's Gateway at the same time. In a worst-case scenario, both projects may wind up at the NEB in parallel review processes with no certainty on the final outcome for another two years.

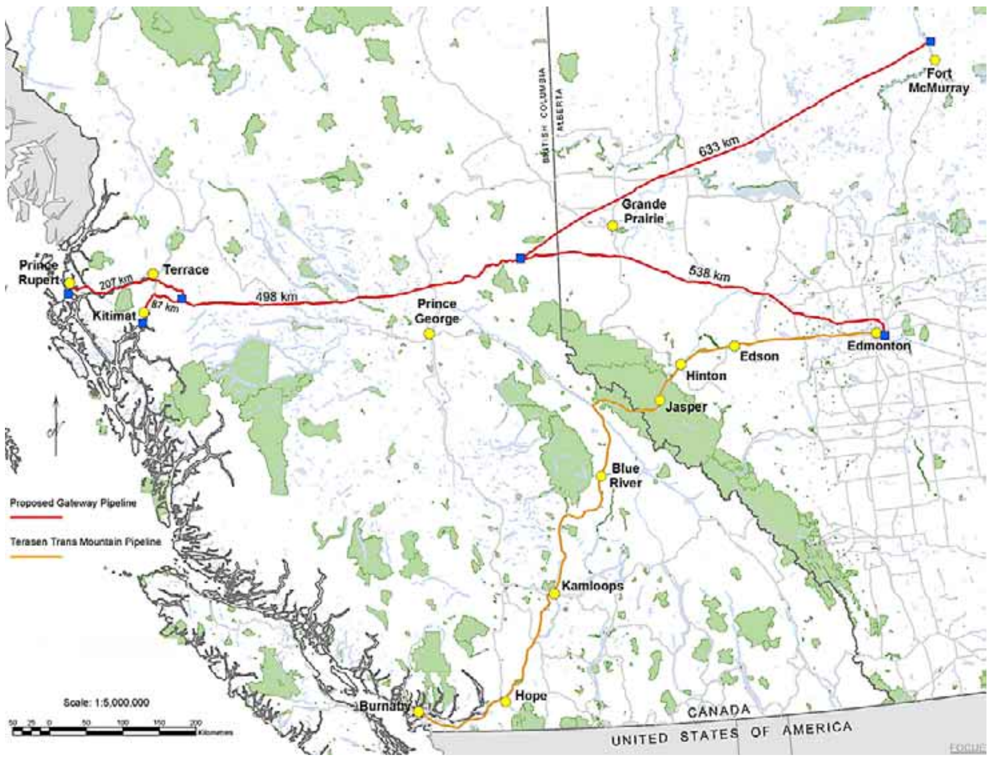
Pipeline investors should hope instead that one of the companies throws up its hands and politely admits defeat. Or even better, that the two companies build one pipeline together. But big new pipelines opening new markets for Canadian oil are the stuff that legacies are made of. Enbridge and Terasen are both deserving of the prize and we expect both will pursue it side by side with passion and vigor.

Enbridge's Gateway Well Advanced – Kitimat The Likely Destination

Enbridge has been studying a new 400,000 barrel-per-day (Bbls/d) pipeline from Edmonton to the West Coast for several years. The Gateway Project now goes well beyond grand visions and lines on a map. Our tour of the proposed project suggests Enbridge is well advanced in the areas of route selection, aboriginal and community consultation and shipper support.

With all the talk of a new dock at Prince Rupert, we were surprised to learn that Kitimat is a significantly more likely final destination for the pipeline. The Gateway Project probably originates in Edmonton and moves to the Coast toward Terrace, British Columbia. It then either splits off to Prince Rupert or to Kitimat. Both towns have deep-water ports shipping natural resources to global markets.

Exhibit 1. Map Of Proposed Gateway Project



Source: Enbridge reports and CIBC World Markets Inc.

We first flew by helicopter from Terrace to Prince Rupert via the potential pipeline route and found it somewhat hostile and environmentally problematic from a construction perspective. The route would at first follow a major hydro right-of-way and the Pacific Northern Gas pipeline route heading west from Terrace. In this initial stage, pipelining would be relatively straightforward.

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Exhibit 2. Existing Right-of-ways Initially Provide An Easy Route Toward Prince Rupert

Source: CIBC World Markets Inc.

The challenges grow as the pipeline route moves further west to the coast. Steep mountains jutting straight up from the Skeena River present construction problems. With no clear right-of-way in these sections, Enbridge would be forced to blast long tunnels above and along the riverbed.

Exhibit 3. There Simply Isn’t Anywhere To Put A Pipeline Along Parts Of The Route To Prince Rupert

Source: CIBC World Markets Inc.

In our view, the biggest challenge for Prince Rupert is the idea of placing an oil pipeline along the pristine Skeena River. The waterway is a major spawning area for salmon and other fish. It may be impossible to avoid silt from moving into the river during construction. Any significant pipeline leak could be seriously hazardous for the environment and fish stocks. We note these challenges are not unique to the Prince Rupert option (Trans Mountain moves through sensitive areas as well), but they may tilt the balance toward Kitimat.

Exhibit 4. Any Oil Leak Along The Pristine Skeena River Could Be Hazardous To Spawning Fish

Source: CIBC World Markets Inc.

Moving oil to Kitimat is no easy feat either, but seems a lot more practical than moving it to Prince Rupert. We flew the potential pipeline route to Kitimat and then well into the harbour and Douglas Channel that the largest tankers would float with up to two million barrels (Bbls) of oil destined for Asia. The route is much less hostile than the route to Prince Rupert. Enbridge has identified wide-open valleys as its potential pipeline route.

Exhibit 5. Rail Lines And Roads In Existing Valleys Make Up The Route To Kitimat

Source: CIBC World Markets Inc.

We did not fully appreciate, prior to our tour, how existing logging roads provide access to the potential pipeline route. Machinery and equipment could be moved in and out of the right-of-way without major environmental disruption and cost. The Kitimat route presents some challenges and may require tunnels in certain bottlenecks, but could cost up to $500 million less than the Prince Rupert route. That cost difference is a meaningful number on a project originally slated for a $2.5 billion total budget.

The port at Kitimat was perhaps the most impressive component of the Gateway tour. There are wide-open spaces for a new dock and Enbridge has already identified and begun engineering work on a relatively flat landmass for new storage tanks.

Exhibit 6. A New Dock Would Go On Shore (Left) With Oil Storage Tanks Just Above (Right)

Source: CIBC World Markets Inc.

The Douglas Channel waterway leading out from Kitimat is deep and largely underutilized. In fact, on our flight we did not see a single watercraft on the inlet. Yet, there were no major bottlenecks and the water was calm.

Exhibit 7. Douglas Channel: No Bottlenecks Or Congestion For The Foreseeable Future

Source: CIBC World Markets Inc.

Enbridge has made progress on community consultation as well as on engineering and route selection. There are about 130 aboriginal communities along the proposed pipeline route. The company has a team with an active outreach and consultation program. We believe Enbridge has also been working directly with key stakeholder groups on environmental and other issues that may affect precise route selection.

Perhaps most important, Enbridge appears to have made progress with Asian shippers. Chief executive Pat Daniel stated at the CIBC Whistler Institutional Investor Conference last week that a memorandum of understanding (MOU) would likely be signed during the current quarter. We think this MOU could involve several Chinese shippers and one or more independent Canadian oil producers.

In summary, we see the Gateway Project as a compelling way to meet shipper needs for a Western alternative well into the future. The Kitimat route appears doable and could accommodate long-term growth for Enbridge and the oil producers.

Terasen Ready To Roll Out Westridge Marine Terminal Expansion

Terasen's proposed TMX expansion involves a doubling of the Trans Mountain Pipeline system and an ultimate increase in capacity from 225,000 Bbls/d to 850,000 Bbls/d. Terasen's project has been criticized for relying on the busy Burrard Inlet (Port of Vancouver) for increased oil shipments. Our tour of the Port and Westridge Dock facilities suggests the company is well on its way to resolving logistical matters that could have otherwise stood in the way.

The logistics of loading more and larger tankers at Westridge did not seem overly problematic. The dock is located at the end of the Harbour with no obvious obstructions in the area.

Exhibit 8. The Westridge Dock Is Located In Probably The Least Busy Section Of The Harbour

Source: CIBC World Markets Inc.

Little work would have to be done on the dock or its infrastructure to increase shipments at the outset. The dock is equipped with scrubbers to minimize air emissions. The 24-inch pipeline now terminates on the dock and attaches to large arms that fill tankers in less than a day.

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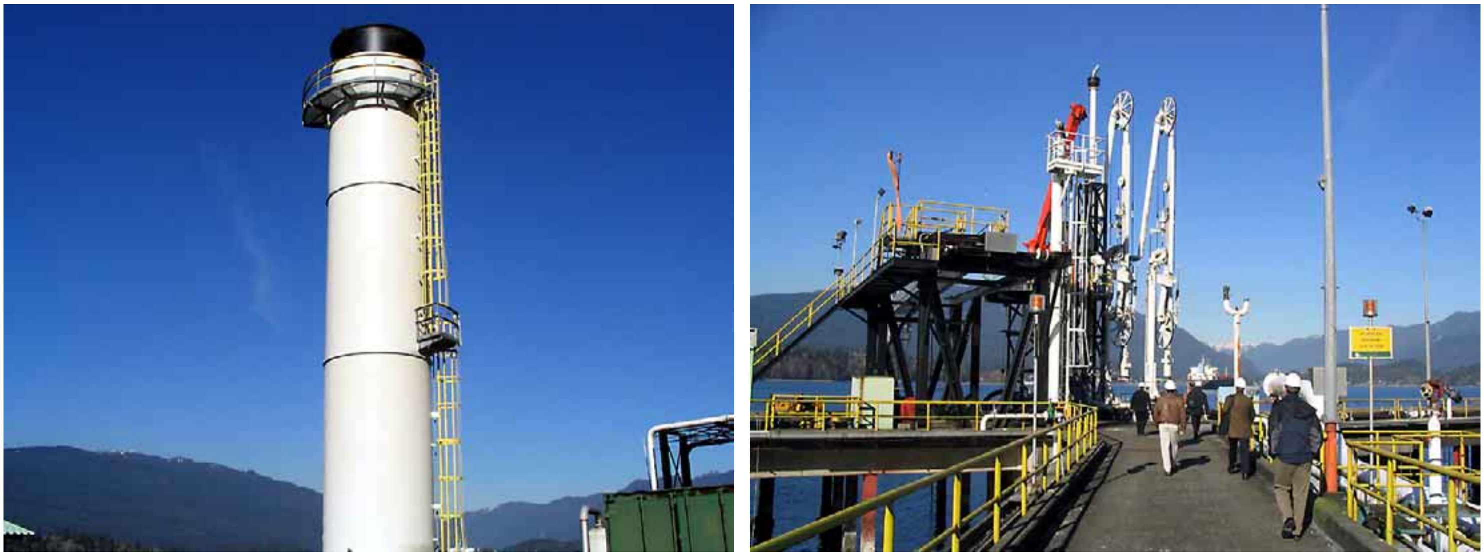
Exhibit 9. The Dock Is Equipped With H_2S Scrubbers (Left) And Oil Loading Arms (Right)



Source: CIBC World Markets Inc.

Key challenges include dredging water off the edge of the dock and then expanding the facility in the longer term. Dredging is necessary to increase the effective cargo capacity of each ship by 100,000 Bbls. Terasen indicated its permit application for dredging is now under consideration by the Port Authority, Department of Fisheries and Department of Environment.

Exhibit 10. Dredging Would Be Permitted Pending Tests On Sediment Off The Dock Berth Face

Source: CIBC World Markets Inc.

We toured the Burnaby oil tank farm that Terasen would expand in conjunction with the TMX project. The company has about 12 large tanks with total capacity of two million Bbls at present. The last tanks were constructed in 1989 but Terasen would add up to six new tanks on site in conjunction with the TMX Project.

Exhibit 11. Burnaby Oil Tanks Work Well Into The Landscape With Room For Expansion


Source: CIBC World Markets Inc.

Terasen has also made good progress on the logistics of navigating the Burrard Inlet with larger ships and more of them. The company has proposed using 80,000 dead-weight-ton Aframax tankers (0.5 million Bbls) as opposed to 50,000 dead-weight-ton Panamax tankers (0.3 million Bbls). It has also proposed sending as many as 10–15 tankers off the dock each month compared to the total of 14 tankers it sent in all of 2004.

The Second Narrows Bridge in the Burrard Inlet poses the most challenging navigation bottleneck. There is a railway bridge that lifts and a highway bridge that does not. Concerns have been raised about the ability to move larger tankers below and between parts of the bridge.

Exhibit 12. The Second Narrows Bridge Is A Logistical Challenge


Source: CIBC World Markets Inc.

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It appears Terasen has done sufficient work to prove Aframax tankers can navigate the Second Narrows Bridge passage. The company has conducted detailed simulations under various conditions. Simulations suggest tankers could consistently navigate through the waterway and out to sea.

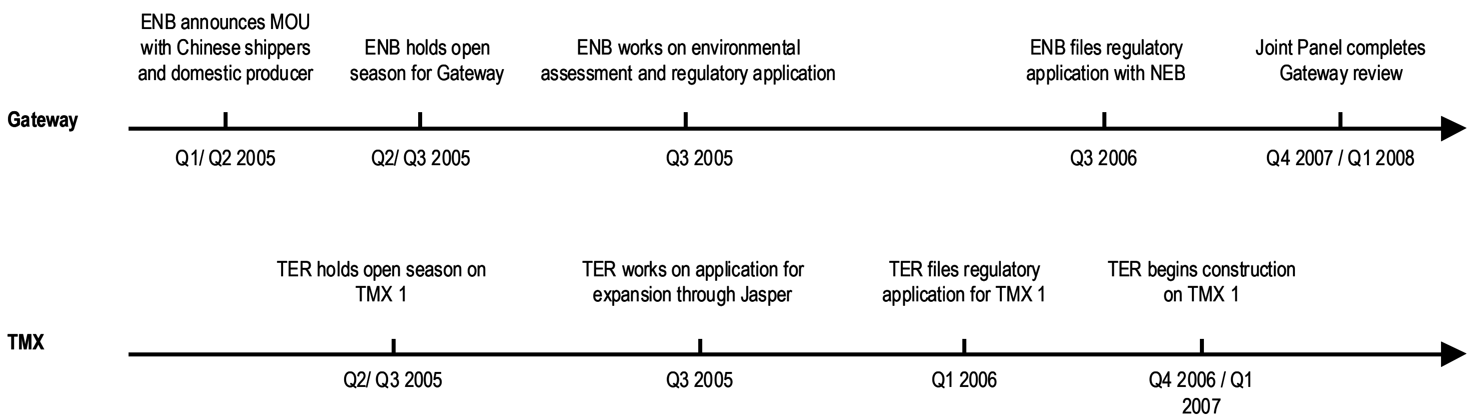
Terasen has already received expressions of interest from parties for the first phase of the Trans Mountain expansion. Last week, Chief Executive John Reid stated at the CIBC World Markets Whistler Institutional Investor Conference that the company plans to proceed with an open season this summer.

In summary, the tour reinforced our view that the Terasen project offers a practical solution to sending more Canadian oil to the Pacific Northwest and California. While shipments out of the Vancouver Harbour may be limited in the very long term, the project likely offers an attractive potential solution for the foreseeable future.

Parallel Processes Could Continue

The viability and soundness of both companies' oil pipeline proposals suggests to us that they will both proceed down parallel tracks for the time being. Enbridge will likely announce a MOU near term and Terasen will commence what is bound to be a successful open season on TMX1. Both companies may wind up pursuing projects in separate regulatory processes at the same time.

Exhibit 13. Enbridge And Terasen's Parallel Processes For New Western Oil Pipelines



Source: Company reports and CIBC World Markets Inc.

One could argue that Terasen has an inside track in the near term because it only needs an incremental 75,000 Bbls/d of support for TMX1, while Enbridge needs more like 350,000 Bbls/d for Gateway. We doubt Enbridge can achieve that level of firm capacity commitment upfront but the company may proceed anyway:

- The toll difference for 300,000 Bbls/d vs. 400,000 Bbls/d is only about $0.45 per Bbl.
- Enbridge has a history of building pipelines that achieve sub-optimal returns initially when there is strong potential for growth in the future (Athabasca, SEP II, Spearhead).

At the same time, Terasen is unlikely to back down even if it appears Gateway has strong support:

- TMX is critical to the company's future growth plans.
- Terasen has a history of building pipelines at sub-optimal returns initially when there is strong potential for growth in the future (Corridor).

Our suggestion that the companies may continue to proceed down a parallel path does not mean their management teams are irrational. Taking slightly sub-optimal returns near term to enhance growth in the future makes sense especially in a climate where asset acquisitions are too expensive. But we are suggesting that the oil pipeline expansions may add a lot more to shareholder value (EPS) in the long term than in the short and medium term.

Conclusions And Potential Resolutions

Last year, we published reports quantifying supply and pipeline capacity. We concluded that there is not room for both pipeline projects. Enbridge and Terasen both corroborate that finding. In that context, there must be some resolution — albeit probably not any time soon — to the competing proposals. We see several possible outcomes:

- ***Gateway wins scenario –*** A pipeline to Kitimat makes more sense to us in the long term than a pipeline to Vancouver. There is little doubt that Terasen can accommodate more volumes in the short and medium term from the Vancouver Port. But in the longer-term, we doubt Vancouver can handle the ultimate volumes that may be destined for Asia. Chinese shippers may well recognize this fact, having observed both the Kitimat and Vancouver ports. Terasen has a proposal for Kitimat that could beat out Gateway, but Enbridge has aligned itself more tightly with a northern route. If Chinese shippers are driving the process, Enbridge and Gateway could win out.

- ***TMX wins as planned scenario –*** The Vancouver Harbour is a practical solution for increasing shipments of oil to California. Chinese shippers may not have sufficient volumes to commit on a 400,000-Bbl pipeline to Kitimat. In this scenario, domestic shippers could select Terasen's staged proposal, slowly sending more oil to California over time.

- ***Terasen surprises with early filing for TMX2 –*** Terasen has the advantage of being slightly ahead of Enbridge in its expansion process. Terasen's open season planned for this summer could attract sufficient interest to justify building phase 2 as well as phase 1. In this instance, the project may default to TMX before Gateway is fully developed or sufficiently subscribed to move forward. This scenario may sound far-fetched, but Terasen management has never been entirely clear on whether TMX1 could be completed independent of TMX2 and TMX3. It may be possible for Terasen to move toward Vancouver with TMX1 and TMX2 at the same time.

- ***Enbridge and Terasen work together on a pipeline to Kitimat –*** If the battle for new Western pipelines carries on for too long, the companies may eventually decide to work together. In this scenario, we could see them using the Trans Mountain right-of-way through Jasper, then head north to Kitimat. At this time, we do not believe the companies are prepared to work on a joint project. But they might be in a year or so if they are still locked in a competitive battle.

In many ways, the battle for a big new pipeline to the West Coast may be just beginning, not nearing an end. Hopefully shippers and oil pipeline companies will converge on the solution before the NEB takes a central role. Commercial interests are generally better arbiters of oil pipelines than government regulators.

Notes: The CIBC World Markets analyst who covers Enbridge visited the company's proposed pipeline route from Terrace, B.C. to Prince Rupert and Kitimat on February 14. CIBC World Markets was responsible for all costs, including those associated with air transportation and accommodations.

The CIBC World Markets analyst who covers Terasen visited the company's Westridge dock facilities on February 16. Terasen was responsible for the cost of transportation to and from the operations. CIBC World Markets was responsible for all other costs involved.

Price Target Calculations

Our price targets for the pipeline and utility companies are derived from P/E multiples and dividend yields (relative to bond yields) based on our 2006 earnings and dividend forecasts. Our target dividend yields range from 2.8%–5.3%. Our target P/E multiples range from 12.0x–19x (in line with historical ranges). In the past 15 years, the stocks have tended to peak at no more than 16x–17x earnings. The differences in target multiples reflect different organic growth rates, potential acquisition activity, and current regulatory environment.

Key Risks To Price Targets

Many of our pipeline and utility stocks could fall short of our 2005 and 2006 earnings forecasts (and fail to meet our price targets) for various fundamental reasons, including (but not limited to) lower-than-expected achieved ROEs, low acquisition activity, and weak power prices/spark spreads. Our estimates on Enbridge and Terasen assume that they continue to earn high incentive returns (above NEB-allowed ROE) on their oil pipelines. The pipeline and utility stocks are sensitive to changes in long-term bond yields. If bond yields rise significantly, valuation in the sector could fall.

Exhibit 14. Comparative Valuation Of Selected Canadian And U.S. Pipeline, Utility And Power Generation Companies

				52-Week Range		Earnings Per Share				P/E Ratios				'05 P/E	Dividend		Payout		
Company	Ticker	Rating / Analyst	Price 02/22/05	High	Low	2003	2004E	2005E	2006E	2003	2004E	2005E	2006E	Rel. To Group	Rate	Yield	2005E	Price Target	Total Return
Canadian Pipelines																			
Enbridge Inc.	ENB	SP / MA	$62.60	$64.79	$47.25	$2.81	$3.02	$3.20	$3.40	22.3	20.7	19.6	18.4	1.1	2.00	3.2%	62.5%	$65.00	7.0%
Terasen Inc.	TER	SP / MA	$28.40	$29.91	$21.50	$1.33	$1.40	$1.50	$1.50	21.4	20.3	18.9	18.9	1.0	0.90	3.2%	60.0%	$29.00	5.3%
TransCanada Corp.	TRP	SO / MA	$30.21	$30.84	$25.37	$1.59	$1.53	$1.65	$1.80	19.0	19.7	18.3	16.8	1.0	1.22	4.0%	73.9%	$33.00	13.3%
Canadian Pipelines Average										**20.9**	**20.3**	**18.9**	**18.0**			**3.5%**	**65.5%**		
U.S. Pipelines																			
Duke Energy	DUK	SO / MA	$26.08	$27.73	$18.85	$1.28	$1.28	$1.60	$1.70	20.4	20.4	16.3	15.3	0.9	1.10	4.2%	68.8%	$29.00	15.4%
El Paso	EP	NR	$12.19	$13.10	$6.57	($1.03)	($0.50)	$0.70	$0.80	NM	NM	17.4	15.2	1.0	0.16	1.3%	22.9%	-	-
Kinder Morgan Inc.	KMI	NR	$78.00	$78.94	$56.85	$3.33	$3.81	$4.21	$4.60	23.4	20.5	18.5	17.0	1.1	2.80	3.6%	66.5%	-	-
National Fuel Gas	NFG	NR	$28.16	$29.15	$23.75	$1.89	$1.98	$1.91	$1.91	14.9	14.2	14.7	14.7	0.8	1.12	4.0%	58.6%	-	-
NiSource	NI	NR	$22.25	$23.18	$19.65	$1.64	$1.63	$1.53	$1.66	13.6	13.7	14.5	13.4	0.8	0.92	4.1%	60.1%	-	-
Williams	WMB	NR	$18.56	$19.19	$8.70	$0.02	$0.42	$0.82	$0.98	NM	44.2	22.6	18.9	1.3	0.20	1.1%	24.4%	-	-
U.S. Pipelines Average										**18.1**	**22.6**	**17.4**	**15.8**			**3.4%**	**55.4%**		
Canadian Utilities																			
ATCO	ACO.NV.X	SU / MA	$60.93	$63.00	$45.65	$4.25	$4.40	$4.60	$4.85	14.3	13.8	13.2	12.6	0.7	1.40	2.3%	30.4%	$58.00	-2.5%
Canadian Utilities	CU.NV	SP / MA	$61.75	$64.00	$51.42	$3.95	$3.78	$4.00	$4.15	15.6	16.3	15.4	14.9	0.8	2.20	3.6%	55.0%	$63.00	5.6%
Caribbean Utilities (US$)	CUP.U	NR	$11.05	$13.76	$9.75	$0.77	$0.11	$0.86	-	14.4	NM	12.8	-	0.7	0.50	4.5%	57.6%	-	-
Emera Inc.	EMA	SP / MA	$19.00	$19.97	$16.40	$1.26	$1.22	$1.15	$1.20	15.1	15.6	16.5	15.8	0.9	0.89	4.7%	77.4%	$19.50	7.3%
Fortis	FTS	SO / MA	$73.52	$75.50	$56.90	$4.25	$4.29	$4.45	$4.80	17.3	17.1	16.5	15.3	0.9	2.28	3.1%	51.2%	$82.00	14.6%
TransAlta Corp.	TA	SU / MA	$18.85	$19.50	$15.25	$0.73	$0.66	$0.70	$1.00	25.8	28.6	26.9	18.9	1.5	1.00	5.3%	142.9%	$19.00	6.1%
Canadian Utilities Average										**17.1**	**18.3**	**16.9**	**15.5**			**3.9%**	**69.1%**		
U.S. Utilities																			
Consolidated Edison	ED	NR	$42.32	$45.59	$37.23	$2.95	$2.67	$2.84	$2.96	14.3	15.9	14.9	14.3	1.0	2.28	5.4%	80.3%	-	-
Dominion Resources	D	NR	$70.00	$72.54	$60.78	$4.50	$4.61	$5.06	$5.37	15.6	15.2	13.8	13.0	1.0	2.68	3.8%	53.0%	-	-
DTE Energy	DTE	NR	$43.21	$45.43	$37.88	$2.97	$2.46	$3.49	$3.85	14.5	17.6	12.4	11.2	0.9	2.06	4.8%	59.0%	-	-
Peoples Energy	PGL	NR	$41.87	$46.03	$38.50	$2.88	$2.56	$2.74	$2.83	14.5	16.4	15.3	14.8	1.1	2.18	5.2%	79.6%	-	-
PPL Corp.	PPL	NR	$53.24	$55.90	$39.85	$3.71	$3.71	$4.09	$4.44	14.4	14.4	13.0	12.0	0.9	1.64	3.1%	40.1%	-	-
WGL Holdings	WGL	NR	$30.11	$31.66	$26.66	$1.62	$1.73	$1.87	$1.91	18.6	17.4	16.1	15.8	1.1	1.30	4.3%	69.5%	-	-
U.S. Utilities Average										**15.3**	**16.1**	**14.3**	**13.5**			**4.4%**	**63.6%**		
Merchant Generation																			
AES Corporation	AES	NR	$16.06	$16.69	$7.56	$0.56	$0.58	$0.84	$0.98	28.7	27.7	19.1	16.4	0.7	0.00	0.0%	0.0%	-	-
Calpine Corp.	CPN	NR	$3.31	$6.19	$2.25	$0.10	($0.77)	($0.55)	($0.23)	33.1	NM	NM	NM	-	0.00	0.0%	0.0%	-	-
Reliant Energy	RRI	NR	$12.35	$13.92	$6.61	$0.42	$0.25	$0.38	$0.59	29.4	49.4	32.5	20.9	1.3	0.00	0.0%	0.0%	-	-
Merchant Generation Average										**30.4**	**38.5**	**25.8**	**18.7**			**0.0%**	**0.0%**		

Estimates are from CIBC World Markets with the exception of those companies that are not rated (Sources: Company reports, First Call and IBES).

Figures for Canadian companies in C$; figures for U.S. companies in US$.

EPS estimates for Caribbean Utilities are for the period ending April 30 the following year.

EPS estimates for PGL, NFG and WGL are for the period ending September 30.

SO = Sector Outperformer; SP = Sector Performer; SU = Sector Underperformer and NR = Not Rated.

Source: Company reports, First Call/ IBES and CIBC World Markets Inc.

Exhibit 15. Comparative Valuation Of Selected Canadian And U.S. Pipeline, Utility And Power Generation Companies

Company	Shares O/S (mlns.)	Mkt. Cap. ($ blns.)	Inst. Owners	52-Week % Change High	52-Week % Change Low	Cash Flow Per Share 2003	Cash Flow Per Share 2004E	Cash Flow Per Share 2005E	Cash Flow Per Share 2006E	P/CF Ratios 2003	P/CF Ratios 2004E	P/CF Ratios 2005E	P/CF Ratios 2006E	Book Value	Price/ Book	ROE 2005E	Debt To Cap	% Unreg. 05E EBIT	EV/ '05E EBITDA
Canadian Pipelines																			
Enbridge Inc.	167.6	$10.5	50%	(3%)	32%	$5.83	$6.15	$6.29	$6.54	10.7	10.2	10.0	9.6	$22.29	2.8	13.5%	67.1%	10.0%	10.1
Terasen Inc.	105.2	$3.0	15%	(5%)	32%	$2.82	$2.83	$3.07	$3.15	10.1	10.0	9.3	9.6	$13.04	2.2	11.1%	65.4%	5.0%	10.5
TransCanada Corp.	484.9	$14.6	45%	(2%)	19%	$3.96	$3.52	$3.66	$3.82	7.6	8.6	8.3	7.9	$13.54	2.2	12.0%	61.0%	16.0%	8.3
Canadian Pipelines Average										**9.5**	**9.6**	**9.2**	**9.0**		**2.4**	**12.2%**	**64.5%**	**10.3%**	**9.7**
U.S. Pipelines																			
Duke Energy	957.0	$25.0	67%	(6%)	38%	$4.35	$4.44	$4.53	$4.65	6.0	5.9	5.8	5.6	$17.18	1.5	9.5%	51.0%	20.0%	7.6
El Paso	643.2	$7.8	79%	(7%)	86%	$3.76				3.2				$6.76	1.8	-	81.4%		9.2
Kinder Morgan Inc.	123.9	$9.7	82%	(1%)	37%	$4.78				16.3				$23.13	3.4	17.1%	44.4%		11.9
National Fuel Gas	83.0	$2.3	46%	(3%)	19%	$4.95	$4.93			5.7	5.9			$16.11	1.7	13.6%	48.8%		6.6
NiSource	270.6	$6.0	73%	(4%)	13%	$2.34	$3.90			9.5	5.9			$17.69	1.3	9.5%	57.0%		7.9
Williams	556.5	$10.3	60%	(3%)	113%	$1.09				17.0				$7.66	2.4	-	68.6%		9.0
U.S. Pipelines Average										**9.6**	**5.9**				**2.0**	**12.4%**	**58.5%**		**8.7**
Canadian Utilities																			
ATCO Ltd.	29.7	$1.8	35%	(3%)	33%	$9.35	$9.15	$10.16	$10.67	6.5	6.7	6.0	5.7	$40.64	1.5	11.1%	50.0%	20.0%	5.9
Canadian Utilities	63.4	$3.9	15%	(4%)	20%	$8.30	$8.35	$8.72	$9.04	7.4	7.4	7.1	6.8	$32.50	1.9	11.8%	51.0%	36.5%	7.3
Caribbean Utilities (US$)	24.9	$0.3	2%	(20%)	13%	$1.32				8.4				$4.63	2.4	16.0%	53.4%	0.0%	8.6
Emera Inc.	108.9	$2.1	18%	(5%)	16%	$2.22	$2.80	$2.87	$3.00	8.6	6.8	6.6	6.3	$12.28	1.5	9.2%	54.0%	5.0%	7.9
Fortis Inc.	23.9	$1.8	32%	(3%)	29%	$9.28	$12.81	$10.50	$10.90	7.9	5.7	7.0	6.7	$41.81	1.8	9.3%	61.5%	21.0%	8.8
TransAlta Corp.	195.0	$3.7	55%	(3%)	24%	$2.86	$3.02	$3.24	$3.50	6.6	6.2	5.8	5.4	$12.74	1.5	5.4%	53.9%	100.0%	8.6
Canadian Utilities Average										**7.6**	**6.6**	**6.5**	**6.2**		**1.8**	**10.5%**	**54.0%**	**30.4%**	**7.8**
U.S. Utilities																			
Consolidated Edison	242.0	$10.2	44%	(7%)	14%	$5.84				7.2				$29.12	1.5	9.3%	49.7%		8.2
Dominion Resources	331.4	$23.2	61%	(4%)	15%	$7.25	$8.00			9.7	9.1			$32.72	2.1	14.1%	59.9%		8.0
DTE Energy	174.2	$7.5	61%	(5%)	14%	$5.63	$5.75			7.7	7.9			$31.85	1.4	8.1%	60.6%		8.4
Peoples Energy	37.9	$1.6	59%	(9%)	9%	$5.57	$5.37			7.5	7.8			$23.37	1.8	12.6%	54.7%		7.8
PPL Corp.	189.0	$10.1	59%	(5%)	34%	$7.82				6.8				$22.42	2.4	18.1%	64.2%		8.5
WGL Holdings	48.7	$1.5	50%	(5%)	13%	$2.96	$4.99			10.2	6.0			$18.11	1.7	10.1%	46.6%		8.7
U.S. Utilities Average										**8.2**	**7.7**				**1.8**	**12.1%**	**56.0%**		**8.3**
Merchant Generation																			
AES Corporation	648.8	$10.4	82%	(4%)	112%	$2.52	$2.43			6.4	6.6			$2.66	-	NM	85.6%	100.0%	7.7
Calpine Corp.	534.3	$1.8	62%	(47%)	47%	$0.69				4.8				$8.68	0.4	0.9%	79.0%	100.0%	13.3
Reliant Energy	298.7	$3.7	72%	(11%)	87%	$2.86				4.3				$15.52	0.8	2.5%	57.0%	100.0%	9.7
Merchant Generation Average										**5.2**					**0.6**	**1.7%**	**73.9%**	**100.0%**	**10.2**

Estimates are from CIBC World Markets with the exception of those companies that are not rated (Sources: Company reports, First Call and IBES).

Figures for Canadian companies in C$; figures for U.S. companies in US$.

For those companies not rated, ROE figures are actuals for the most recent fiscal year.

EPS estimates for Caribbean Utilities are for the period ending April 30 the following year.

EPS estimates for NFG, PGL and WGL are for the period ending September 30.

Source: Company reports, First Call / IBES and CIBC World Markets Inc.

IMPORTANT DISCLOSURES:

Analyst Certification: Each CIBC World Markets research analyst named on the front page of this research report, or at the beginning of any subsection hereof, hereby certifies that (i) the recommendations and opinions expressed herein accurately reflect such research analyst's personal views about the company and securities that are the subject of this report and all other companies and securities mentioned in this report that are covered by such research analyst and (ii) no part of the research analyst's compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by such research analyst in this report.

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In addition to 1% ownership positions in covered companies that are required to be specifically disclosed in this report, CIBC World Markets may have a long position of less than 1% or a short position or deal as principal in the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon.

Recipients of this report are advised that any or all of the foregoing arrangements, as well as more specific disclosures set forth below, may at times give rise to potential conflicts of interest.

Important Disclosure Footnotes for Companies Mentioned in this Report that Are Covered by CIBC World Markets:

Stock Prices as of 02/24/2005:
Atco Ltd. (13, 7) (ACO.NV.X-TSX, C$60.37, Sector Underperformer)
Canadian Utilities Ltd. (13, 7) (CU.NV-TSX, C$61.00, Sector Performer)
Duke Energy (2a, 2d, 2g, 7) (DUK-NYSE, US$26.71, Sector Outperformer)
Emera Inc. (2g, 7) (EMA-TSX, C$19.08, Sector Performer)
Enbridge Inc. (2a, 2e, 2g, 7) (ENB-TSX, C$61.38, Sector Performer)
Fortis Inc. (2a, 2c, 2e, 2g, 7) (FTS-TSX, C$73.50, Sector Outperformer)
Terasen Inc. (2a, 2c, 2e, 2g, 7) (TER-TSX, C$28.09, Sector Performer)
TransAlta Corporation (2a, 2e, 2g, 7, 9) (TA-TSX, C$18.75, Sector Underperformer)
TransCanada Corp. (2g, 7) (TRP-TSX, C$29.97, Sector Outperformer)

Companies Mentioned in this Report that Are Not Covered by CIBC World Markets:

Stock Prices as of 02/24/2005:
AES Corp (AES-NYSE, US$16.34, Not Rated)
Calpine Corporation (CPN-NYSE, US$3.26, Not Rated)
Caribbean Utilities Company Ltd. (CUP.U-TSX, C$11.25, Not Rated)
Consolidated Edison (ED-NYSE, US$42.63, Not Rated)
Dominion Resources (D-NYSE, US$70.51, Not Rated)
DTE Energy Company (DTE-NYSE, US$43.18, Not Rated)
El Paso Corp. (EP-NYSE, US$11.93, Not Rated)
Kinder Morgan, Inc. (KMI-NYSE, US$78.56, Not Rated)
National Fuel Gas (NFG-NYSE, US$28.05, Not Rated)
Nisource (NI-NYSE, US$22.30, Not Rated)
Peoples Energy (PGL-NYSE, US$42.41, Not Rated)
PPL Corporation (PPL-NYSE, US$53.85, Not Rated)
Reliant Energy Inc. (RRI-NYSE, US$12.19, Not Rated)
WGL Holdings (WGL-NYSE, US$30.20, Not Rated)
Williams Cos Inc. (WMB-NYSE, US$18.77, Not Rated)

Important disclosure footnotes that correspond to the footnotes in this table may be found in the "Key to Important Disclosure Footnotes" section of this report.

Key to Important Disclosure Footnotes:

1	CIBC World Markets Corp. makes a market in the securities of this company.
2a	This company is a client for which a CIBC World Markets company has performed investment banking services in the past 12 months.
2b	CIBC World Markets Corp. has managed or co-managed a public offering of securities for this company in the past 12 months.
2c	CIBC World Markets Inc. has managed or co-managed a public offering of securities for this company in the past 12 months.
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2f	CIBC World Markets Corp. expects to receive or intends to seek compensation for investment banking services from this company in the next 3 months.
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3c	CIBC World Markets Inc. has received compensation for non-investment banking, securities-related services from this company in the past 12 months.
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4b	CIBC World Markets Corp. has received compensation for non-investment banking, non-securities-related services from this company in the past 12 months.
4c	CIBC World Markets Inc. has received compensation for non-investment banking, non-securities-related services from this company in the past 12 months.
5a	The CIBC World Markets Corp. analyst(s) who covers this company also has a long position in its common equity securities.
5b	A member of the household of a CIBC World Markets Corp. research analyst who covers this company has a long position in the common equity securities of this company.
6a	The CIBC World Markets Inc. analyst(s) who covers this company also has a long position in its common equity securities.
6b	A member of the household of a CIBC World Markets Inc. research analyst who covers this company has a long position in the common equity securities of this company.
7	CIBC World Markets Corp., CIBC World Markets Inc., and their affiliates, in the aggregate, beneficially own 1% or more of a class of equity securities issued by this company.
8	A partner, director or officer of CIBC World Markets Inc. or any analyst involved in the preparation of this research report has provided services to this company for remuneration in the past 12 months.
9	A senior executive member or director of Canadian Imperial Bank of Commerce ("CIBC"), the parent company to CIBC World Markets Inc. and CIBC World Markets Corp., or a member of his/her household is an officer, director or advisory board member of this company or one of its subsidiaries.
10	Canadian Imperial Bank of Commerce ("CIBC"), the parent company to CIBC World Markets Inc. and CIBC World Markets Corp., has a significant credit relationship with this company.
11	The equity securities of this company are restricted voting shares.
12	The equity securities of this company are subordinate voting shares.
13	The equity securities of this company are non-voting shares.
14	The equity securities of this company are limited voting shares.

CIBC World Markets Price Chart

For price and performance information charts required under NYSE and NASD rules, please visit CIBC on the web at http://www.cibcwm.com/research/sec2711 or write to CIBC World Markets Corp., 300 Madison Avenue, 7th Floor, New York, NY 10017-6204, Attn: Research Disclosure Chart Request.

CIBC World Markets' Stock Rating System

Abbreviation	Rating	Description
Stock Ratings		
SO	Sector Outperformer	Stock is expected to outperform the sector during the next 12-18 months.
SP	Sector Performer	Stock is expected to perform in line with the sector during the next 12-18 months.
SU	Sector Underperformer	Stock is expected to underperform the sector during the next 12-18 months.
NR	Not Rated	CIBC does not maintain an investment recommendation on the stock.
R	Restricted	CIBC World Markets is restricted*** from rating the stock.
Stock Ratings Prior To August 26, 2002		
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B	Buy	Expected total return over 12 months of at least 15%.
H	Hold	Expected total return over 12 months of at least 0%-15%.
UP	Underperform	Expected negative total return over 12 months.
S	Suspended	Stock coverage is temporarily halted.
DR	Dropped	Stock coverage is discontinued.
R	Restricted	Restricted
UR	Under Review	Under Review
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O	Overweight	Sector is expected to outperform the broader market averages.
M	Market Weight	Sector is expected to equal the performance of the broader market averages.
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**Broader market averages refer to the S&P 500 in the U.S. and the S&P/TSX Composite in Canada.

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Sector Outperformer (Buy)	281	33.3%	Sector Outperformer (Buy)	173	61.6%
Sector Performer (Hold/Neutral)	396	47.0%	Sector Performer (Hold/Neutral)	223	56.3%
Sector Underperformer (Sell)	165	19.6%	Sector Underperformer (Sell)	76	46.1%
Restricted	0	0.0%	Restricted	0	0.0%

Ratings Distribution: Pipelines, Utilities, & Power Coverage Universe

(as of 24 Feb 2005)	Count	Percent	Inv. Banking Relationships	Count	Percent
Sector Outperformer (Buy)	3	30.0%	Sector Outperformer (Buy)	3	100.0%
Sector Performer (Hold/Neutral)	5	50.0%	Sector Performer (Hold/Neutral)	3	60.0%
Sector Underperformer (Sell)	2	20.0%	Sector Underperformer (Sell)	1	50.0%
Restricted	0	0.0%	Restricted	0	0.0%

Pipelines, Utilities, & Power Sector includes the following tickers: ACO.NV.X, CU.NV, DUK, EEP, EMA, ENB, FTS, TA, TER, TRP.

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CIBC World Markets

Equity Research
Earnings Update

May 05, 2005

Pipelines, Utilities, & Power

Stock Rating:
Sector Performer

Sector Weighting:
Market Weight

12-18 mo. Price Target	$29.00
TER-TSX (5/4/05)	$27.45
Key Indices: TSXUtils	
3-5-Yr. EPS Gr. Rate (E)	6.0%
52-week Range	$22.00-$29.91
Shares Outstanding	105.4M
Float	104.9M Shrs
Avg. Daily Trading Vol.	94,104
Market Capitalization	$2,893.2M
Dividend/Div Yield	$0.90 / 3.3%
Fiscal Year Ends	December
Book Value	$13.45 per Shr
2005 ROE (E)	11.1%
LT Debt	$2,147.7M
Preferred	Nil
Common Equity	$1,418.5M
Convertible Available	Yes

Earnings per Share	Prev	Current
2004		$1.40A
2005		$1.50E
2006		$1.50E
P/E		
2004		19.6x
2005		18.3x
2006		18.3x

Dividends per Share	
2002	$0.705
2003	$0.765
2004	$0.825
2005E	$0.90

Debt to Total Capital	
2002	66.2%
2003	67.0%
2004	65.4%

Company Description
Terasen is a gas distribution and oil pipeline company. Its subsidiary, Terasen Gas, distributes natural gas to B.C., including Vancouver and the interior.

www.terasen.com

Matthew Akman
1 (416) 956-6169
Matthew.Akman@cibc.ca

Alda Pavao, CFA
1 (416) 956-3229
Alda.Pavao@cibc.ca

Terasen Inc.

Q1 Earnings Slightly Soft As Expected

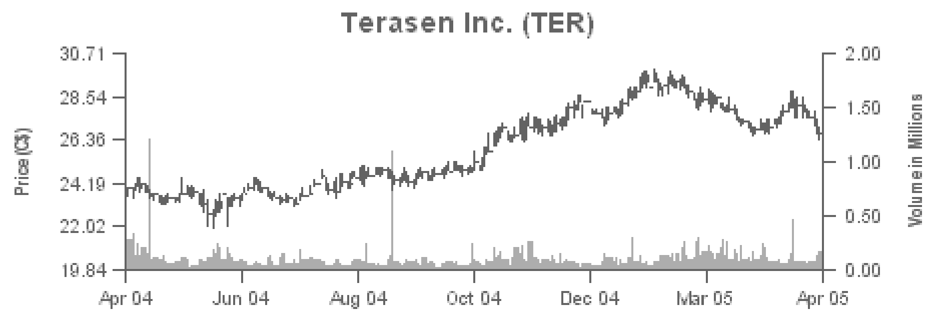
- Terasen reported normalized Q1'05 EPS of $0.60 vs. our estimate of $0.58 and $0.63 in Q1'04. A temporary reduction in oil pipeline volumes caused the weakness and was factored into our numbers. We are maintaining our estimates and target price.

- Management maintained full-year EPS guidance of $1.45 - $1.50, excluding Q1 mark-to-market gains of $0.02 - $0.03. Our earnings estimate of $1.50 is now slightly vulnerable. However, oil volumes have rebounded as of April, and should support earnings in Q2 - Q4.

- Several attractive investment opportunities at Terasen remain on track. The ones we find most promising for the 2006 - 2008 period are an expansion of the Corridor Oil Pipeline, TMX Phase 1, and construction of LNG storage facilities on Vancouver Island.

- We remain concerned about the December 31, 2005, expiry of a lucrative tolling agreement on the Trans Mountain Pipeline. Our Sector Performer rating balances attractive expansion opportunities against the risk of a 2006 reduction in the Trans Mountain toll.

Stock Price Performance



Source: Reuters

All figures in Canadian dollars, unless otherwise stated.

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See "Price Target Calculation" and "Key Risks to Price Target" sections at the end of this report, where applicable.

Investment Summary

Terasen reported normalized Q1'05 EPS of $0.60 vs. our estimate of $0.58 and $0.63 in Q1'04. A temporary reduction in oil pipeline volumes caused the weakness and was factored into our numbers. We are maintaining our estimates and target price.

Please see the appendix to this comment for a full breakdown and analysis of normalizing items and earnings by segment.

Slow Start to 2005 – Earnings Should Improve in Q2 – Q4

The first quarter earnings demonstrate Terasen's earnings sensitivity to volume throughput on its oil pipelines. Volume flows on Trans Mountain were 170,000 b/d in Q1'05 vs. 240,000 b/d in Q1'04. As a result, despite capital expansions last year, earnings were lower in Q1'05 than Q1'04.

Our earnings estimate is slightly vulnerable in the context of a slow start to 2005. However, improvements in the oil pipeline division should boost earnings in Q2 - Q4:

- The Trans Mountain expansion that went into service in September of 2004 allows for increased volumes that should show up starting in Q2. Trans Mountain was 35% over-subscribed in May.
- The Express expansion came into service in April and should be immediately additive to earnings (84% of total expanded capacity is long-term contracted).

Management maintained full-year EPS guidance of $1.45 - $1.50 excluding $0.02 - $0.03 in Q1 mark-to-market gains. We are maintaining our EPS estimates perhaps with a slight downward bias due to a slightly weak first quarter.

Investment Opportunities Intact

Several attractive investment opportunities at Terasen remain on track. The ones we find most promising for the 2006 - 2008 period are an expansion of the Corridor Oil Pipeline, TMX1, and construction of LNG storage facilities on Vancouver Island:

- ***Corridor Pipeline expanding with Shell oil sands output –*** Shell (SHC-TSX, Sector Performer) will likely require a 110,000 b/d expansion on the Corridor Pipeline by 2009. The capital cost is estimated at $700 - $800 million.
- ***Vancouver Island LNG still moving forward –*** The BC Utilities Commission has approved a $100 million LNG storage facility that should be added to Vancouver Island gas distribution rate base by 2007.
- ***TMX stage 1 open season for this summer –*** Terasen plans to hold an open season for the first stage of its TMX project. The $570 million project could be in service by 2008.

The rest of the TMX project is still in direct competition against the Enbridge (ENB – TSX, Sector Performer) Gateway proposal. We continue to maintain the view (confirmed by management on the conference call) that Terasen may proceed with Phase 1 of the Trans Mountain expansion even if it does not have firm commitments for all phases of the TMX project. We do not anticipate any final decision on TMX2 and TMX3 vs. Gateway until 2006.

Tolling Renewal Risk Overhangs Stock

We remain concerned about the December 31, 2005, expiry of a lucrative tolling agreement on the Trans Mountain Pipeline. Our calculations suggest the company is earnings an ROE of around 20% (vs. allowed of 9.5%). Every 100

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basis point reduction in the ROE is worth $0.01 - $0.02 in EPS. Therefore we see material downside earnings risk on Trans Mountain starting in 2006. Indications from parallel negotiations at Enbridge are that shippers will request a significant reduction in the ROE. Based on recent negotiations with shippers, Enbridge has publicly stated that the ROE on its Mainline will probably drop. Enbridge expects its embedded low-teens ROE will fall to the National Energy Board allowed level of about 9.5%.

Some mitigating factors are working in Terasen's favour. Shippers may be slightly more charitable to Terasen because of the volume throughput risk on Trans Mountain. Enbridge has no material volume risk on the Canadian portion of its pipeline. In addition, Terasen may be able to offer expansion capacity in exchange for an ROE that exceeds the NEB allowed 9.5%.

These mitigating factors allow us to forecast an attractive mid-teens ROE on Trans Mountain in 2006. However, based on the Enbridge situation, we doubt Terasen can fully avoid a reduction in the ROE and toll. Therefore our earnings forecast for 2006 is flat to 2005.

By 2007 or 2008, Terasen should return to a growth trajectory similar to its 6%+ average in recent years. Our Sector Performer rating on Terasen balances the near-term earnings risk for 2006 against attractive expansion opportunities that should contribute to renewed growth later in the decade.

Appendix: Summary of Q1'05 Results

We normalized Terasen's reported Q1'05 EPS to $0.60 per share by excluding a $2.6 million (after-tax) mark-to-market gain related to natural gas hedges at Clean Energy.

Exhibit 1. Segmented Earnings for Terasen

(data in C$ millions, unless otherwise stated)

	Q105A	Q1/04A	2005E	2004A
Terasen Gas	$49.0	$48.0	$70.2	$69.7
Terasen Gas (Vancouver Island)	$6.7	$6.7	$26.2	$26.2
Trans Mountain Pipeline	$5.4	$10.4	$39.5	$39.4
Express Pipeline System	$3.7	$4.0	$20.0	$15.9
Corridor Pipeline	$3.6	$3.9	$15.6	$15.6
Water and Utility Services	$0.8	$0.0	$11.0	$6.6
Other Activities	($5.5)	($6.8)	($25.0)	($26.9)
Operating Earnings for Common	**$63.7**	**$66.2**	**$157.5**	**$146.5**
Unusual Items	$2.6	$1.7	$2.6	$3.3
Reported Earnings	$66.3	$67.9	$160.1	$149.8
Average Shares Outstanding (mln)	105.3	104.6	105.2	104.7
Operating Earnings per Share	**$0.60**	**$0.63**	**$1.50**	**$1.40**
Reported Earnings per Share	$0.63	$0.65	$1.52	$1.43

Notes:

1. Unusual item in Q1/05 relates to $2.6 million after-tax gain from mark-to-market accounting on Terasen's share of Clean Energy's natural gas positions.
1. Unusual item in 2004 relates to $3.3 million gains from mark-to-market accounting on Terasen's share of Clean Energy's natural gas positions.

Source: Company reports and CIBC World Markets Inc.

Natural Gas Distribution

Earnings from the B.C. gas utilities improved by $1 million as a result of lower financing costs (low interest rates) and operational efficiencies.

Petroleum Transportation

As expected, **Trans Mountain Pipeline**'s earnings were down y/y due to lower volumes on both the Canadian (down almost 30%) and US mainlines (down over 50%). Production slowdown from oil sands operations and planned U.S. refinery turnarounds caused Trans Mountain volumes to drop. But the company has indicated that the oil pipeline has returned to full capacity in Q2.

Earnings from **Express Pipeline System** came in slightly lower than expected, at $3.7 million in Q1'05 vs. $4.0 million in Q1'04 and our $4 million estimate. Volume throughput on Express was also negatively impacted by delayed oil sands production from Syncrude. But volumes should improve materially starting in Q2 due to higher contracted capacity post 108 MBbl/day expansion.

A lower allowed ROE contributed to the $0.3 million decrease in **Corridor's** Q1 earnings.

Water and Utility Services

The $0.8 million earnings contribution from the Water and Utility Services segment reflects growth in the waterworks business and a small Fairbanks contribution (seasonally weaker Q1/Q4).

Other Activities

Excluding a $2.6 million mark-to-market gain from Clean Energy, Other Activities contributed a loss of $5.5 million in Q1'04, down from $6.8 million loss last year. A focus on costs and operating efficiencies offset higher interest costs in the quarter.

Price Target Calculation

Our $29 target price is based on a 19.3x multiple of our 2006 EPS forecast of $1.50. It also implies a 3.3% dividend yield. Given Terasen's superior long-term growth prospects and low risk profile, we are using a target P/E multiple at the higher end of the group average, but within the stock's historical trading range of 8x-20x earnings.

Key Risks to Price Target

Terasen could fall short of our 2005 and 2006 earnings forecasts (and fail to meet our target price) for various reasons, including (but not limited to) the lower allowed ROEs on its regulated gas distribution business and a reduction of the toll on its Trans Mountain pipeline. In addition, the stocks are sensitive to changes in Canadian long bond yields. If broader market risk dissipates and bond yields rise significantly, valuation in the sector could fall.

Our EPS estimates are shown below:

	1 Qtr.	2 Qtr.	3 Qtr.	4 Qtr.	Yearly
2004 Current	$0.63A	$0.17A	$0.08A	$0.52A	$1.40A
2005 Current	$0.60A	$0.22E	$0.12E	$0.56E	$1.50E
2006 Current	--	--	--	--	$1.50E

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2g CIBC World Markets Inc. expects to receive or intends to seek compensation for investment banking services from Terasen Inc. in the next 3 months.

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Enbridge Inc. (2a, 2c, 2e, 2g, 7) (ENB-TSX, $64.30, Sector Performer)

Shell Canada Limited (2g, 6a) (SHC-TSX, $86.80, Sector Performer)

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2d CIBC World Markets Corp. has received compensation for investment banking services from this company in the past 12 months.

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2g CIBC World Markets Inc. expects to receive or intends to seek compensation for investment banking services from this company in the next 3 months.

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5b A member of the household of a CIBC World Markets Corp. research analyst who covers this company has a long position in the common equity securities of this company.

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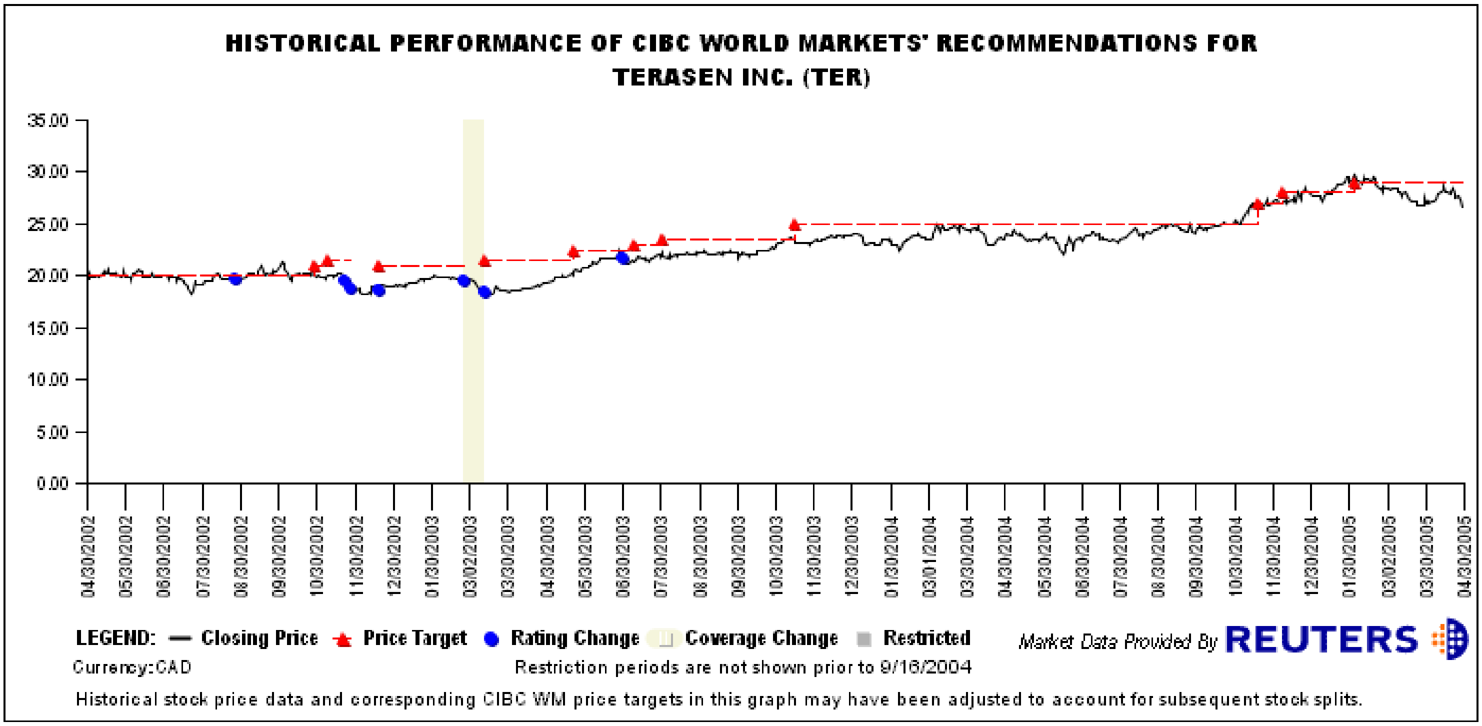

HISTORICAL PERFORMANCE OF CIBC WORLD MARKETS' RECOMMENDATIONS FOR TERASEN INC. (TER)

Date	Change Type	Closing Price	Rating	Price Target	Coverage
08/26/2002	●	19.66	SU	20.00	Peter Case
10/28/2002	▲	20.10	SU	21.00	Peter Case
11/07/2002	▲	20.13	SU	21.50	Peter Case
11/21/2002	●	19.48	SP	21.50	Peter Case
11/25/2002	▲●	18.85	NR	None	Peter Case
12/18/2002	▲●	18.63	SP	21.00	Peter Case
02/24/2003	▲●□	19.51	S	None	CIBC World Markets Corp.
03/12/2003	▲●□	18.41	SO	21.50	Matthew Akman
05/21/2003	▲	20.13	SO	22.50	Matthew Akman
06/30/2003	●	21.78	SP	22.50	Matthew Akman
07/08/2003	▲	21.30	SP	23.00	Matthew Akman
08/01/2003	▲	21.93	SP	23.50	Matthew Akman
11/13/2003	▲	23.58	SP	25.00	Matthew Akman
11/15/2004	▲	27.00	SP	27.00	Matthew Akman
12/06/2004	▲	27.00	SP	28.00	Matthew Akman
02/01/2005	▲	29.71	SP	29.00	Matthew Akman

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Abbreviation	Rating	Description
Stock Ratings		
SO	Sector Outperformer	Stock is expected to outperform the sector during the next 12-18 months.
SP	Sector Performer	Stock is expected to perform in line with the sector during the next 12-18 months.
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Sector Performer (Hold/Neutral)	390	45.4%	Sector Performer (Hold/Neutral)	215	55.1%
Sector Underperformer (Sell)	149	17.3%	Sector Underperformer (Sell)	75	50.3%
Restricted	17	2.0%	Restricted	16	94.1%

Ratings Distribution: Pipelines, Utilities, & Power Coverage Universe

(as of 04 May 2005)	Count	Percent	Inv. Banking Relationships	Count	Percent
Sector Outperformer (Buy)	3	27.3%	Sector Outperformer (Buy)	1	33.3%
Sector Performer (Hold/Neutral)	6	54.5%	Sector Performer (Hold/Neutral)	4	66.7%
Sector Underperformer (Sell)	2	18.2%	Sector Underperformer (Sell)	1	50.0%
Restricted	0	0.0%	Restricted	0	0.0%

Pipelines, Utilities, & Power Sector includes the following tickers: ACO.NV.X, CU.NV, DUK, EEP, EMA, ENB, FTS, RRI, TA, TER, TRP.

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Corporate Debt Comments

May 5, 2005

Trevor Bateman, CFA, CA
(416) 594-7992
Banks, Non-bank financials, Autos, ABS

Phillip Armstrong
(416) 956-3272
Telecom, Cable, Insurance, Retail, Consumer Products

Kevin Yong, CFA
(416) 956-6273
Oil & Gas, Utilities, Aerospace

Joanna Zapior, CFA, CMC
(416) 594-8498
Strategy

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Terasen: 1Q05 results weaker as expected but no impact on bonds

Kevin Yong (416) 956-6273 kevin.yong@cibc.ca
Joanna Zapior (416) 594-8498 joanna.zapior@cibc.ca

CREDIT IMPACT: Neutral. We maintain our Market Perform rating on Terasen Inc. and Terasen Gas bonds. As expected, Terasen reported weaker year-over-year earnings and cash flow. Since the main driver (lower pipeline throughput) for weaker cash flow was a temporary event, there should be no impact on bond spreads or credit ratings from 1Q05 results. Credit protection measures showed slight improvement on a year-over-year comparison despite the weaker cash flow. [Terasen Inc.: A(low)/Stable; A3/Stable] and [Terasen Gas: A/Stable; A2/Stable]

- Terasen's weaker cash flow was due to weaker earnings contribution from the Petroleum Transportation segment. Weaker earnings from this segment were a result of lower throughput at Trans Mountain and Express – both throughputs were negatively impacted by oil sands production outages and refinery maintenance. **Given that the lower throughputs were caused by temporary short-term production and refinery outages, the weaker cash flow reported in 1Q05 has no material impact on credit.**
- Although net borrowings increased in the quarter, the increase in leverage was offset by an increase in cash balance. As a result, net debt was essentially flat compared to net debt at the end of 2004 and increased by 1% compared to 1Q04 net debt level. This was the primary reason why credit metrics showed a slight improvement despite softer year-over-year cash flow generation.

CREDIT METRICS

Terasen: 1Q05	Debt to CF	Debt to Cap at book	EBITDA to Interest	FFO to Interest	LTM Realized ROE	LTM CF	LTM FCF
1Q05	10.6	67.3%	3.0	1.6	9.6%	276	-18
1Q04	10.0	67.9%	2.7	1.5	9.9%	289	28
4Q04	9.9	68.2%	3.0	1.7	11.7%	296	95

CONSOLIDATED QUARTERLY RESULTS SUMMARY

	Revenue	EBITDA	Net Interest Expense	Earnings	FFO	Free Cash Flow	Net borrowings (repayment) of debt	Share Issuance (repurchase)	Net Debt
year-over-year change	3%	-3%	0%	-2%	-6%	-96%	220%	-47%	1%
quarter-over-quarter change	8%	10%	-3%	19%	13%	-91%	159%	5%	0%
1Q05	$667	$172	$45	$66	$99	$5	$115	$4	$2,926
1Q04	$649	$177	$45	$68	$105	$117	-$96	$8	$2,904
4Q04	$616	$156	$47	$56	$87	$56	-$194	$4	$2,936

SELECTED OPERATING STATISTICS

	1Q05	1Q04	4Q04	YTD 03
Operating Statistics:				
Number of gas customers	878,560	862,631	875,166	875,166
Gas transportation volume (in petajoules)	21.6	21.9	19.6	72
Trans Mountain Canadian Mainline (bbl/d)	170,000	240,400	239,100	236,100
Trans Mountain US Mainline (bbl/d)	44,500	93,300	89,300	91,700
Express System (bbl/d)	166,900	171,300	175,400	175,300

- Despite lower reported earnings and cash flow from 1Q05, management is maintaining its full-year 2005 earnings guidance.
- The lower earnings contribution from the pipelines was partially offset by a small improvement in gas distribution earnings, earnings from water utilities, and lower corporate expenses.
- Terasen Gas earnings improved by $1 million in 1Q05 compared 1Q04. Operating efficiencies and customer growth more than offset lower allowed ROE in 2005.

Please refer to Our Opinions table (below) to place this credit in its sector-relative-value context

	Analyst	Senior unsecured DBRS	Senior unsecured Moody's	Senior unsecured S&P	Credit fundamentals (1-3 years)	Rating change probab. (1 year)	Valuation	YTD total return Shorter bond Bond	YTD total return Shorter bond Return	YTD total return Longer bond Bond	YTD total return Longer bond Return	YTD change in spread Shorter bond Curr Sprd		YTD change in spread Shorter bond YTD Chng	YTD change in spread Longer bond Curr Sprd		YTD change in spread Longer bond YTD Chng
Pipelines: *Solid, largely regulated fundamentals, though regulatory environment disadvantages those companies that have North American growth plans as Cdn leverage is higher and returns lower. Our investment thesis rests on two pillars: 1) operating excellence and cost management will be key in light of 2) regulators pressuring for cost control, including returns. Holding company risk has been increasing with expansion in non-regulated areas, equity market push for growth, and still elevated leveragex*																	
Gas distribution: *Stable sector, with strong operating franchises and good fundamentals. However, no standalone credits left (exceptand credit quality is affected by parent activities. See also our comment on the pipeline sector.*																	
Enbridge Inc	**KY**	A	A3	A-	May weaken (M&A, projects)	Medium	C	5.8% 2008	1.52%	8.2% 2024	3.93%	37	▲	1	103	▲	2
Enbridge Pipelines	**KY**	A(high)	NR	A-	Stable	Medium	R	5.621% 2007	1.07%	7.2% 2032	4.59%	37	▲	7	130	▲	5
Enbridge Gas Dist.	**KY**	A	NR	A-	Stable	Medium	R	11.15% 2009	1.74%	6.1% 2028	4.48%	57	▲	6	104	▲	3
Alliance Pipe	**KY**	A(low)	A3	BBB+	Strong	Very low	F	7.23% 2015	3.44%	7.217% 2025	3.42%	39	▼	24	98	▼	1
There are continued M&A and large project risks - lots of noise in the news as juggling for positions continues. The market now prices its uncertainty about committment to "A" ratings. Pipe acquisition in the GoM has eroded current balance sheet to the lev continue permissible under the S&P rating. Over time, we see balance sheet quality potentially weakening as more risky assets may be added while mature, stable assets end up in income trust. That it has historically been a defensive credit (low spread volatility) under the pause but history may not repeat itself. We view **opcos** as better credits in line with DBRS logic but not necessarily better value. Note **EGD** has a 2005 rate case. Regulatory stability has improved after a recent spate of decisions & PBR is possible. Mainline is renegotiating its settlement this fall. For **Alliance,** we like the "structuring premium" of an amortizer and the simplicity of this credit; not affected by how the ownership is structured; valuation reflects the defensive nature of this credit. It continues to perform as expected. Mgt turnover has been signficant (CFO earlier and now CEO) but this has no credit impact either for this contractually structured credit																	
TransCanada	**KY**	A	A2	A- Neg	Stable but event risk	Medium	R	6.05% 2007	1.27%	6.5% 2030	3.90%	31	▼	5	125	▲	10
Neg outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand (the most recent big one of a U.S. pipeline appears to have crystallized the agency thinking in a constructive way, subject to how conservative mgt will remainik will tak financing side) . Expansion in generation and another potential large opportunistic acquisition & large projects in the longer term are credit risks. Regulatory environment continues to be unsatisfactory in mgt's eyes which raises questions about whetheing si company will want to trustify some of the lower return regulated assets - a potential negative for bondholders.																	
Duke (Westcoast)	**KY**	A(low)	NR	BBB	Improving	Low	R	5.7% 2008	1.74%	7.15% 2031	3.02%	40	▼	6	140	▲	17
Duke (Union Gas)	**KY**	A	NR	BBB	Standalone stbl + DUK effect	Low	R	5.7% 2008	1.71%	8.65% 2025	3.19%	36	▼	5	126	▲	12
MNEP	**KY**	A	A1 UR-PD	A	Strong	Very low	F	NA	NA	6.9% 2019	2.86%	NA		NA	84	▲	4
Duke took steps to turn the corner and the balance sheet repair actions have finally shown. Exit from non-core businesses continue & core regulated operations are stable. We think DENA will continue to be a source of grief for a while until markets improvesteps to t the new idea of contributing it to a joint venture hatches (lowering of risk). Resumed talk of opportunistic growth means that the golden age for bondholders is almost over (some upside remains from DENA cleanup & possible upgrade). We believe, in the loidea of **Union Gas's** distribution portion, as a non-core asset, is more separable from Duke than Westcoast. Its storage is a strategic asset to Duke. In the short term, Union provides solid cash flow to Duke and supports its credit quality. Spreads have performed reasonably well & are now in the middle of the utiltiy pack, leaving little further room for outperformance. For **MNEP**, we like structural protection and simplicity; valuation reflects the defensive nature of this credit.																	
Terasen	**KY**	A(low)	A3	BBB-	Stable but some event risk	Low	C	6.3% 2008	1.92%	NA	NA	52	▼	6	NA		NA
Terasen Gas	**KY**	A	A2	BBB	Stable	Low	C	NA	NA	6.95% 2029	5.57%	NA		NA	126	▼	3
Business fundamentals are a strong combination of a regulated gas distribution and pipelines, with aggressive financial profile determining the rating. Market pricing suggests that the market does not give full credence to the S&P rating (but still incorpoundamental despite its now unsolicited status). Project CAPEX could be high. For **Terasen Gas**, we like the fundamentals of gas distribution at current spread, compared to historical spreads, but don't think that holdco spread can tighten much in the near term.																	
Electric T&D: *Regulated; should have reasonably stable credit protection. Dark cloud of S&P and DBRS negative outlook on Ontario reflects political risk rather than material risk of deterioration in credit quality, and has by now almost dissipated though stability in the sector has not entirely returned. Our investment thesis is that given a general regulatory/rating agency/issuer stand-off, operating excellence and low cost structure will be key differentiating factors, given the aging assets and broad grid restructuot entirely retu North America.*																	
Hydro One	**KY**	A Pos	A2	A	Stable	Low	R	7.15% 2010	2.21%	6.93% 2032	4.68%	34	▼	1	85	▲	4
Quasi-provincial credit nature still somewhat offset by political noise although the most recent policy changes appear to bypass Hydro One (with one exception being taking away from it the responsibility for long-term planning of the network); fairly valueovincial "provincially-supported" credit, otherwise expensive. Liberal government appears to be more constructive for the electricity sector than the Conservatives have been in terms of power market functionality, while the risk of divestiture remains very low.																	
Toronto Hydro	**KY**	A	NR	A-	Stable	Low	R	6.11% 2013	2.42%	NA	NA	63	▲	6	NA		NA
Some political and regulatory uncertainties remain. Scarcity value supports valuation. Recent political developments increase our confidence in a positive restructuring of the industry, including regulatory environment. Volatile non-regulated business ccal and reg impact earnings - mitigating factor is that TH said it will exit retail electricity by end 2006. We think that in the medium term performance-based regulation will introduce marginally higher operating risk.																	

Our ratings:

Market Perform. The issuer's bonds are expected to perform in line with our universe of bonds over the next 12 months.
Outperfrom. The issuer's bonds are expected to outperform our universe of bonds over the next 12 months.
Underperform. The Issuer's bonds are expected to underperform our universe of bonds over the next 12 months.

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CIBC World Markets

Equity Research
Earnings Update

July 29, 2005

Pipelines, Utilities, & Power

Terasen Inc.

Small Target Increase Following Express Pipeline Upside

Stock Rating:
Sector Performer

Sector Weighting:
Market Weight

12-18 mo. Price Target	$31.00
TER-TSX (7/28/05)	$31.64

Key Indices: TSXUtils

3-5-Yr. EPS Gr. Rate (E)	6.0%
52-week Range	$23.07-$31.78
Shares Outstanding	105.5M
Float	105.2M Shrs
Avg. Daily Trading Vol.	94,104
Market Capitalization	$3,339.4M
Dividend/Div Yield	$0.90 / 2.8%
Fiscal Year Ends	December
Book Value	$13.53 per Shr
2005 ROE (E)	11.2%
LT Debt	$2,029.1M
Preferred	Nil
Common Equity	$1,427.5M
Convertible Available	Yes

Earnings per Share	Prev	Current
2004		$1.40A
2005	$1.50E	$1.50E
2006	$1.50E	$1.55E
P/E		
2004		22.6x
2005	21.1x	21.1x
2006	21.1x	20.4x

Dividends per Share	
2002	$0.705
2003	$0.765
2004	$0.825
2005E	$0.90

Debt to Total Capital	
2003	67.0%
2004	65.4%
2005E	65.2%

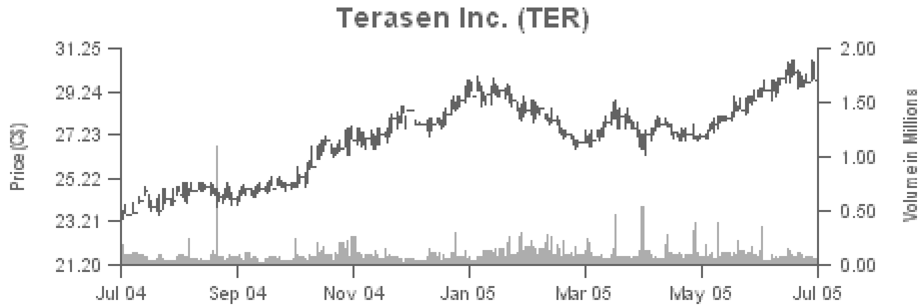
Company Description

Terasen is a gas distribution and oil pipeline company. Its subsidiary, Terasen Gas, distributes natural gas to B.C., including Vancouver and the interior.

www.terasen.com

- Terasen reported normalized Q2'05 EPS of $0.23 vs. our estimate of $0.22 and $0.16 in Q2'04. Earnings from the Express Pipeline surprised on the upside. We are raising our 2006 EPS estimate to $1.55 (from $1.50) and our target price to $31 (from $30).
- The Express Pipeline expansion went into service in April of this year. Management had previously guided to a $0.05 EPS contribution but is now disclosing a contribution of more like $0.10. The change in guidance causes us to raise our 2006 EPS estimate by $0.05.
- News on longer-term growth initiatives was mixed. On the one hand, the company now anticipates a delay of up to two years on the Vancouver Island LNG storage facility. On the other hand, a major expansion on the Corridor oil pipeline appears on track.
- The upside surprise on Express likely allows Terasen to continue growing earnings in 2006 despite a pending expiry of the lucrative Trans Mountain tolling agreement. We are raising our target price to $31 and maintaining our Sector Performer rating.

Stock Price Performance



Source: Reuters

All figures in Canadian dollars, unless otherwise stated.

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See "Price Target Calculation" and "Key Risks to Price Target" sections at the end of this report, where applicable.

Matthew Akman
1 (416) 956-6169
Matthew.Akman@cibc.ca

Alda Pavao, CFA
1 (416) 956-3229
Alda.Pavao@cibc.ca

Investment Summary

Terasen reported normalized Q2'05 EPS of $0.23 vs. our estimate of $0.22 and $0.16 in Q2'04. Earnings from the Express Pipeline surprised on the upside. We are raising our 2006 EPS estimate by $0.05 and our target price by $1.

For a breakdown and analysis of earnings by segment and normalizing items, please see the appendix to this comment.

Express Pipeline Surprises on the Upside

The Express Pipeline expansion went into service in April of this year. Management had previously guided to a $0.05 EPS contribution but is now disclosing a contribution of more like $0.10.

The change in outlook is likely related to tax planning rather than improved project economics. Our best guess would have been that project economics were running in line with expectations. Volume flows are strong but electricity costs have moved up since the expansion was announced. Therefore, the upside is likely attributable to the unique Express structure. In fact, management disclosed that tax benefits will deliver about $4 million in annual net income ($0.04 in EPS).

Whether from tax planning or other factors, the change in outlook on Express causes a $0.05 increase in our 2006 EPS estimate. On its own it would also have caused us to raise estimates by about $0.03 in 2005 but weakness in Trans Mountain offsets the upside this year. Management disclosed Trans Mountain volume flows weakened temporarily in the third quarter. We assume these disruptions are temporary and will not recur in 2006.

Oil Pipeline Growth Initiatives Still on Track

News on longer-term growth initiatives was mixed. On the one hand, the company now anticipates a delay of up to two years on the Vancouver Island LNG storage facility and has deferred the Inland Pacific Connector (IPC). On the other hand, we have never been optimistic about the IPC project and the company's major oil pipeline expansion activities remain on track:

- ***Expansion on Corridor by 2009 –*** Shell (SHC-TSX, Sector Performer) will likely require an expansion of at least 110,000 b/d on the Corridor Pipeline by 2009. Terasen is planning a 200,000 b/d expansion for an estimated cost of $700 - $800 million. The company is seeking third party shippers but expansion is not dependent on success in adding to the list of shippers.
- ***Trans Mountain phase 1 moving forward –*** Terasen has already applied to the National Energy Board for a 35,000 b/d expansion that will be achieved by investing $210 million in additional pumping. We think an open season this summer should solidify support for an additional $365 million investment in looping that would add another 40,000 b/d to Trans Mountain capacity by 2009.

Whether Terasen can achieve full support for the second and third phases of Trans Mountain expansion remains to be seen. We anticipate shippers will first focus on major expansion to the core Midwest market. Given market uncertainties and the tight competition between Enbridge (ENB – TSX, Sector Performer) and Terasen, it is conceivable shippers will not finally decide on any large expansion to the West Coast until the 2006/7 timeframe.

Most But Not All of the ROE Reduction Can Be Offset

Terasen is facing potentially significant reductions in the ROEs on its existing gas distribution and oil pipeline assets. We think some, but not all, of the impacts can be offset:

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- ***Trans Mountain tolling renewal suggests small hit only –*** We believe management will succeed in avoiding a large reduction in the ROE on Trans Mountain. Enbridge has recently established a tolling precedent suggesting limited downside for Terasen. Having said that, we believe shippers will require some reduction in returns and seek relatively low returns on the initial Trans Mountain expansion proposals.
- ***Gas Distribution ROE hearing begins soon* –** Terasen may offset some or all of the formula ROE reduction for its gas utility business through a hearing commencing next month. The company has requested a 500 basis point increase in its equity ratio and a 175 basis point increase in its allowed ROE. We anticipate Terasen will receive sufficient benefit to offset an anticipated 50 basis point reduction that would normally have resulted from its formula ROE.

Conclusions: Outlook Improving But Stock Already Up

Prior to the Q2 result we had modeled no EPS increase in 2006 relative to 2005. We had seen a modest decrease in pipeline and gas distribution ROEs offset by growth in Express earnings. Our view is largely unchanged except the Express earnings may be enough to more than offset the ROE reductions. Therefore, we are raising our target price by $1.

In recent weeks Terasen shares have already reflected the improved outlook. After lagging other utility stocks in the first half of the year the stock has caught up in a short period. As a result, it is again trading at a premium P/E multiple (20.3x 2006 vs. group at 18x). Our Sector Performer rating balances the improved outlook against recent share price appreciation.

Appendix: Summary of Q2'05 Results

We normalized Terasen's reported Q2'05 EPS to $0.23 by excluding a $3.9 million (after-tax) mark-to-market gain related to natural gas hedges at Clean Energy and tax benefits provided by the Express expansion attributable to Q1 (about $1 million impact).

Exhibit 1. Segmented Earnings for Terasen

(data in C$ millions, unless otherwise stated)

	Q2/05A	Q2/04A	2005E	2004A
Terasen Gas	$1.6	($1.2)	$71.0	$69.7
Terasen Gas (Vancouver Island)	$6.1	$6.3	$26.2	$26.2
Trans Mountain Pipeline	$9.8	$9.0	$40.1	$39.4
Express Pipeline System	$6.6	$3.2	$22.0	$15.9
Corridor Pipeline	$3.5	$4.0	$14.2	$15.6
Water and Utility Services	$3.8	$2.6	$10.0	$6.6
Other Activities	($6.8)	($6.6)	($25.4)	($26.9)
Operating Earnings for Common	**$24.6**	**$17.3**	**$158.1**	**$146.5**
Unusual Items	$3.9	$0.6	$6.6	$3.3
Reported Earnings	$28.5	$17.9	$164.7	$149.8
Average Shares Outstanding (mln)	105.5	104.7	105.5	104.7
Operating Earnings per Share	**$0.23**	**$0.17**	**$1.50**	**$1.40**
Reported Earnings per Share	$0.27	$0.17	$1.56	$1.43

Notes:

1. Unusual item in Q2/05 relates to $3.9 million after-tax gain from mark-to-market accounting on Terasen's share of Clean Energy's natural gas positions.
2. Unusual item in 2004 relates to $3.3 million gains from mark-to-market accounting on Terasen's share of Clean Energy's natural gas positions.

Source: Company reports and CIBC World Markets Inc.

Natural Gas Distribution

Earnings from the B.C. gas utilities improved by $1.6 million due in part to timing issues on capital maintenance spend and operational efficiencies.

Terasen filed two regulatory applications with the BCUC in Q2. The first requests an extension of the Terasen Gas Vancouver Island's PBR arrangement by another 2 years. The second application requests a review of the automatic ROE formula and allowed equity ratios. TER is seeking a 175 basis point improvement in allowed ROE and 5% increase in equity thickness. A procedural review of the application has been set for August 3.

Petroleum Transportation

Trans Mountain Pipeline's earnings rebounded from a weak Q1 as a result of strong throughput. Volume growth on the Canadian mainline was up a solid 8.3% y/y.

The normalized $3.4 million increase in **Express'** Q2 earnings contribution was driven by the 108,000 Bbls/d capacity expansion (about $2 million impact) completed in April and realization of additional tax benefits (estimated $1.3 million attributable to Q2).

A lower allowed formula ROE contributed to the $0.5 million decrease in **Corridor's** Q2 earnings.

Water and Utility Services

The $1.2 million increase in Water Utility earnings was attributable to solid organic growth and acquisitions. Management indicated on the call that growth opportunities in this sector are plentiful right now, particularly in Alberta and Alaska.

Other Activities

Excluding a $3.9 million mark-to-market gain from Clean Energy, Other Activities contributed a loss of $5.8 million in Q2'05, up from a $6.6 million loss last year. Effective Q2'05, Terasen changed its accounting for Clean Energy (from proportionate consolidation to equity) due to a less joint control (40.4%, down from 45% in 2004).

Price Target Calculation

Our $31 target price is based on a 20x multiple of our 2006 EPS forecast of $1.55. It also implies a 3% dividend yield. Given Terasen's superior long-term growth prospects and low risk profile, we are using a target P/E multiple at the higher end of the group average, but within the stock's historical trading range of 8x-20x earnings.

Key Risks to Price Target

Terasen could fall short of our 2006 earnings forecasts (and fail to meet our target price) for various reasons, including (but not limited to) the lower allowed ROEs on its regulated gas distribution business and a lower than forecast throughout on its oil pipelines. In addition, the stocks are sensitive to changes in Canadian long bond yields. If broader market risk dissipates and bond yields rise significantly, valuation in the sector could fall.

Our EPS estimates are shown below:

	1 Qtr.	2 Qtr.	3 Qtr.	4 Qtr.	Yearly
2004 Current	$0.63A	$0.16A	$0.08A	$0.52A	$1.40A
2005 Prior	$0.60A	$0.22E	$0.12E	$0.56E	$1.50E
2005 Current	$0.61A	$0.23A	$0.11E	$0.55E	$1.50E
2006 Prior	--	--	--	--	$1.50E
2006 Current	--	--	--	--	$1.55E

IMPORTANT DISCLOSURES:

Analyst Certification: Each CIBC World Markets research analyst named on the front page of this research report, or at the beginning of any subsection hereof, hereby certifies that (i) the recommendations and opinions expressed herein accurately reflect such research analyst's personal views about the company and securities that are the subject of this report and all other companies and securities mentioned in this report that are covered by such research analyst and (ii) no part of the research analyst's compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by such research analyst in this report.

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In addition to 1% ownership positions in covered companies that are required to be specifically disclosed in this report, CIBC World Markets may have a long position of less than 1% or a short position or deal as principal in the securities discussed herein, related securities or in options, futures or other derivative instruments based thereon.

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2e CIBC World Markets Inc. has received compensation for investment banking services from Terasen Inc. in the past 12 months.

2g CIBC World Markets Inc. expects to receive or intends to seek compensation for investment banking services from Terasen Inc. in the next 3 months.

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Enbridge Inc. (2a, 2c, 2e, 2g, 7) (ENB-TSX, $35.25, Sector Performer)

Shell Canada Limited (2a, 2e, 2g, 6a) (SHC-TSX, $35.55, Sector Performer)

Important disclosure footnotes that correspond to the footnotes in this table may be found in the "Key to Important Disclosure Footnotes" section of this report.

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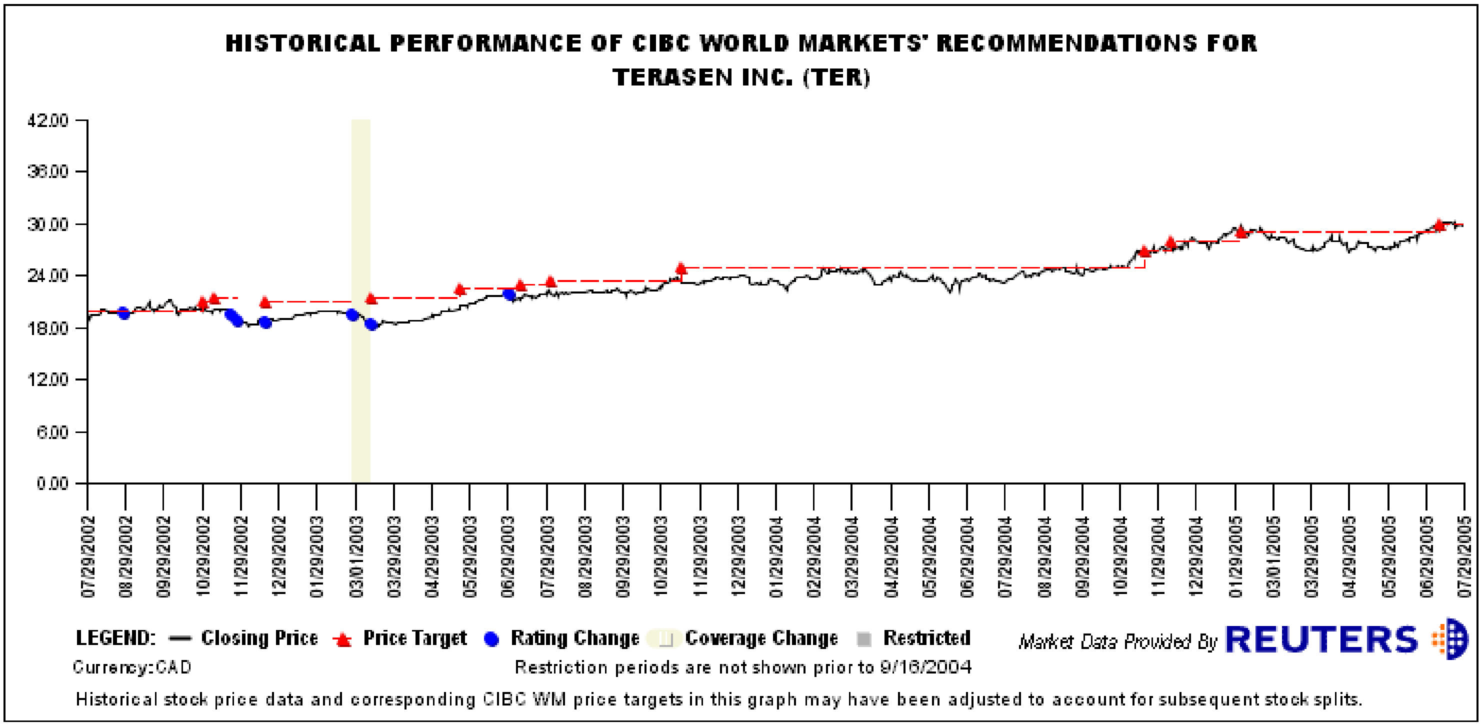
11	The equity securities of this company are restricted voting shares.
12	The equity securities of this company are subordinate voting shares.
13	The equity securities of this company are non-voting shares.
14	The equity securities of this company are limited voting shares.

CIBC World Markets Price Chart



HISTORICAL PERFORMANCE OF CIBC WORLD MARKETS' RECOMMENDATIONS FOR TERASEN INC. (TER)

Date	Change Type	Closing Price	Rating	Price Target	Coverage
08/26/2002	●	19.66	SU	20.00	Peter Case
10/28/2002	▲	20.10	SU	21.00	Peter Case
11/07/2002	▲	20.13	SU	21.50	Peter Case
11/21/2002	●	19.48	SP	21.50	Peter Case
11/25/2002	▲●	18.85	NR	None	Peter Case
12/18/2002	▲●	18.63	SP	21.00	Peter Case
02/24/2003	▲●□	19.51	S	None	CIBC World Markets Corp.
03/12/2003	▲●□	18.41	SO	21.50	Matthew Akman
05/21/2003	▲	20.13	SO	22.50	Matthew Akman
06/30/2003	●	21.78	SP	22.50	Matthew Akman
07/08/2003	▲	21.30	SP	23.00	Matthew Akman
08/01/2003	▲	21.93	SP	23.50	Matthew Akman
11/13/2003	▲	23.58	SP	25.00	Matthew Akman
11/15/2004	▲	27.00	SP	27.00	Matthew Akman
12/06/2004	▲	27.00	SP	28.00	Matthew Akman
02/01/2005	▲	29.71	SP	29.00	Matthew Akman
07/08/2005	▲	29.90	SP	30.00	Matthew Akman

CIBC World Markets' Stock Rating System

Abbreviation	Rating	Description
Stock Ratings		
SO	Sector Outperformer	Stock is expected to outperform the sector during the next 12-18 months.
SP	Sector Performer	Stock is expected to perform in line with the sector during the next 12-18 months.
SU	Sector Underperformer	Stock is expected to underperform the sector during the next 12-18 months.
NR	Not Rated	CIBC does not maintain an investment recommendation on the stock.
R	Restricted	CIBC World Markets is restricted*** from rating the stock.
Stock Ratings Prior To August 26, 2002		
SB	Strong Buy	Expected total return over 12 months of at least 25%.
B	Buy	Expected total return over 12 months of at least 15%.
H	Hold	Expected total return over 12 months of at least 0%-15%.
UP	Underperform	Expected negative total return over 12 months.
S	Suspended	Stock coverage is temporarily halted.
DR	Dropped	Stock coverage is discontinued.
UR	Under Review	Under Review
Sector Weightings**		
O	Overweight	Sector is expected to outperform the broader market averages.
M	Market Weight	Sector is expected to equal the performance of the broader market averages.
U	Underweight	Sector is expected to underperform the broader market averages.
NA	None	Sector rating is not applicable.

**Broader market averages refer to the S&P 500 in the U.S. and the S&P/TSX Composite in Canada.
"Speculative" indicates that an investment in this security involves a high amount of risk due to volatility and/or liquidity issues.
***Restricted due to a potential conflict of interest.
"CC" indicates Commencement of Coverage. The analyst named started covering the security on the date specified.

Ratings Distribution*: CIBC World Markets' Coverage Universe

(as of 28 Jul 2005)	Count	Percent	Inv. Banking Relationships	Count	Percent
Sector Outperformer (Buy)	285	33.7%	Sector Outperformer (Buy)	162	56.8%
Sector Performer (Hold/Neutral)	399	47.2%	Sector Performer (Hold/Neutral)	229	57.4%
Sector Underperformer (Sell)	139	16.4%	Sector Underperformer (Sell)	72	51.8%
Restricted	16	1.9%	Restricted	15	93.8%

Ratings Distribution: Pipelines, Utilities, & Power Coverage Universe

(as of 28 Jul 2005)	Count	Percent	Inv. Banking Relationships	Count	Percent
Sector Outperformer (Buy)	3	27.3%	Sector Outperformer (Buy)	2	66.7%
Sector Performer (Hold/Neutral)	6	54.5%	Sector Performer (Hold/Neutral)	4	66.7%
Sector Underperformer (Sell)	2	18.2%	Sector Underperformer (Sell)	1	50.0%
Restricted	0	0.0%	Restricted	0	0.0%

Pipelines, Utilities, & Power Sector includes the following tickers: ACO.NV.X, CU.NV, DUK, EEP, EMA, ENB, FTS, RRI, TA, TER, TRP.

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Friday, July 29, 2005

CIBCWM Bond Rating:

Market Perform

Credit Ratings: Terasen Inc.

S&P: BBB-/Stable

Moody's: A3/Stable

DBRS: A (low)/Stable

Credit Ratings: Terasen Gas

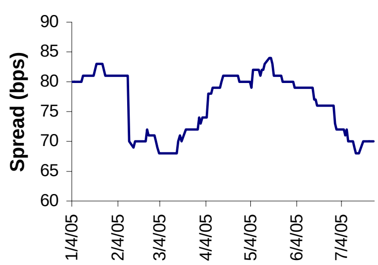
S&P: BBB/Stable

Moody's: A2/Stable

DBRS: A/Stable

Bond Spreads

TER 5.56% 9/15/2014



Source: CIBC World Markets

Kevin Yong

416-956-6273
kevin.yong@cibc.ca

Joanna Zapior

416-594-8498
joanna.zapior@cibc.ca

Pipelines & Utilities

Terasen Inc.

Better 2Q05 financial results from all segments

CREDIT IMPACT: Neutral. Quarterly financial and operating results were neutral for credit and do not change our view on the credit of Terasen Inc. or Terasen Gas. Leverage ratios remain high, relative to peers such as Enbridge, but are stable to slightly improved on a year-over-year and quarter-over-quarter basis. As expected, year-over-year increases in quarterly earnings and cash flow were mostly attributed to improved earnings from the petroleum transportation segment, which was a result of increased throughput at Trans Mountain and Express expansion. Terasen Gas earnings also exhibited solid growth due to customer growth and lower operating expenses. We remain **Market Perform** on both Terasen Inc. and Terasen Gas.

Figure 1: Credit metrics are stable to slightly improved

Terasen Inc.	Net Debt to CF	Net Debt to Cap at book	EBITDA to Interest	FFO to Interest	LTM Realized ROE	LTM CF	LTM FCF
2Q05	9.9	67.2%	3.0	1.7	11.9%	297	-48
2Q04	10.0	67.9%	2.8	1.5	10.6%	287	78
1Q05	10.1	67.3%	2.9	1.6	11.1%	290	-18

Sources: Company reports, CIBC World Markets

- **Credit metrics slightly improved** – as shown in Figure 1, credit metrics are stable to slightly improved on a year-over-year and quarter-over-quarter comparison. Net debt to capitalization has been fairly stable over the last six quarters in and around the 68% level for five of the last six quarters; exception was 4Q04 when this ratio ticked up to 69.6%. Coverage ratios remain solid on a year-over-year and quarter-over-quarter comparison.
- **Cash flow improved but free cash flow was negative** – growth in cash flow before working capital (FFO) was mostly a result of higher quarterly earnings. Free cash flow was slightly negative due to lower cash from working capital and higher CAPEX.
- **Trans Mountain's new incentive tolling settlement (ITS)** – management said on the conference call that discussions with the shippers were going well and that it expects a new agreement by the end of 2005. Strong support from shippers for the first phase of TMX 1 is positive for ITS negotiation.
- **Corridor expansion** – this is estimated to cost about $800 million. The proposed expansion is two-fold. The first would be increasing pumping capacity on the existing line, with a second phase involving the construction of a new 42-inch pipeline. Current capacity of 258 mbbl/d should increase to 278 mbbl/d by April 2006. Addition of new pipeline is expected to increase capacity to about 480 mbbl/d by 2009. Terasen expects to have some third-party shippers on the expanded capacity.

Trevor Bateman, CFA, CA
(416) 594-7992
Banks, Non-bank financials, Autos, ABS

Phillip Armstrong
(416) 956-3272
Telecom, Cable, Insurance, Retail, Consumer Products

Kevin Yong, CFA
(416) 956-6273
Oil & Gas, Utilities, Aerospace

Joanna Zapior, CFA, CMC
(416) 594-8498
Strategy

Dina Giacomelli –Editor
(416) 956-6056

CIBC World Markets Inc. PO Box 500, 161 Bay Street, BCE Place, Toronto, Canada M5J 2S8 Bloomberg@wgec1 **(416) 594-7000**
CIBC World Markets Corp. 300 Madison Avenue, New York, NY 10017 **(212) 856-4000, (800) 999-6726**

Figure 2: Earnings and FFO growing year-over-year

	Revenue	EBITDA	Net Interest Expense	Earnings	FFO	Free Cash Flow	Net borrowings (repayment) of debt	Share Issuance (repurchase)	Net Debt
year-over-year change	13%	9%	3%	65%	12%	-105%	-18%	25%	2%
quarter-over-quarter change	-38%	-37%	-3%	-56%	-39%	-131%	-143%	-63%	0%
2Q05	$412	$109	$44	$30	$61	-$1	-$49	$2	$2,927
2Q04	$365	$100	$43	$18	$54	$28	-$42	$1	$2,877
1Q05	$667	$172	$45	$66	$99	$5	$115	$4	$2,926

Sources: Company reports, CIBC World Markets

- **Year-over-year increase in earnings came from all segments.** Natural gas earnings improved by $2.6 million in 2Q05 compared to 2Q04. Petroleum transportation earnings improved by $4.7 million in 2Q05 relative to 2Q04. Water and utility services earnings grew by $1.2 million year-over-year in the quarter.

- **Terasen Gas grows steadily** – improvement in earnings was due to strong customer growth, which is a result of a healthy economic environment in B.C., and better operating efficiencies. Both of these positives more than offset the lower allowed ROE in 2005 versus 2004; therefore, 2Q05 earnings increased by $2.6 million over 2Q04 earnings. Improved efficiencies resulted in a year-over-year decline in quarterly operating and maintenance expense of $1.8 million in 2Q05.

- **Petroleum transportation earnings strengthened due to a rebound in volume on Trans Mountain and higher than expected earnings from Express expansion** – Trans Mountain earnings improved by $0.8 million in 2Q05 over 2Q04 earnings. The big lift in earnings came from the Express expansion, which surprised to the upside with earnings of $7.6 million in 2Q05 compared to $3.2 million in 2Q04. Realization of additional tax benefits helped to boost the earnings in the quarter.

- **Water and utility services continue to grow slowly and steadily** – 2Q05 earnings from this segment improved to $3.8 million in 2Q05 compared to $2.6 million in 2Q04. Improved earnings were a result of growth in the Waterworks business from Alberta and B.C. and contribution from Fairbanks Sewer and Water. Management indicated on the conference call that it will continue to grow this business through small projects that provide good steady growth opportunities.

Figure 3: Growing liquids pipeline throughput and natural gas customers

Operating Statistics:	2Q05	2Q04	1Q05	2004
Number of gas customers	879,647	862,752	878,560	875,166
Gas transportation volume (in petajoules)	15.8	16	21.6	72
Trans Mountain Canadian Mainline (bbl/d)	242,100	223,500	170,000	236,100
Trans Mountain US Mainline (bbl/d)	74,600	97,400	44,500	91,700
Express System (bbl/d)	226,500	176,200	166,900	175,300

Sources: Company reports

Please refer to Our Opinions table (below) to place this credit in its sector-relative-value context

26-Jul-05	Analyst	Senior unsecured DBRS	Moody's	S&P	Credit fundamentals (1-3 years)	Rating change probab. (1 year)	Valuation	YTD total return Shorter bond Bond	Return	Longer bond Bond	Return	YTD change in spread Shorter bond Curr Sprd	YTD Chng	Longer bond Curr Sprd	YTD Chng
Pipelines: *Solid, largely regulated fundamentals, though regulatory environment disadvantages those companies that have North American growth plans as Cdn leverage is higher and returns lower. Our investment thesis rests on two pillars: 1) operating excellence and cost management will be key in light of 2) regulators pressuring for cost control, including returns. Holding company risk has been increasing with expansion in non-regulated areas, equity market push for growth, and still elevated leverage.*															
Gas distribution: *Stable sector, with strong operating franchises and good fundamentals. However, no standalone credits left (exceptand credit quality is affected by parent activities. See also our comment on the pipeline sector.*															
Enbridge Inc	KY	A	A3	A-	May weaken (M&A, projects)	Medium	C	5.8% 2008	2.59%	8.2% 2024	8.73%	32	▼ 4	90	▼ 11
Enbridge Pipelines	KY	A(high)	NR	A-	Stable	Medium	R	5.621% 2007	1.86%	7.2% 2032	10.70%	29	▼ 1	116	▼ 9
Enbridge Gas Dist.	KY	A	NR	A-	Stable	Medium	R	11.15% 2009	2.96%	6.1% 2028	9.77%	55	▲ 4	95	▼ 6
Alliance Pipe	KY	A(low)	A3	BBB+	Strong	Very low	F	7.23% 2015	4.76%	7.217% 2025	5.82%	36	▼ 27	91	▼ 8
There are continued M&A and large project risks - lots of noise in the news as jockeying for positions continues. The market now prices its uncertainty about committment to "A" ratings. Pipe acquisition in the GoM has eroded current balance sheet to the lecontinued permissible under the S&P rating. Over time, we see balance sheet quality potentially weakening as more risky assets may be added while mature, stable assets end up in income trust. That it has historically been a defensive credit (low spread volatility) under the pause but history may not repeat itself. We view opcos as better credits in line with DBRS logic but not necessarily better value. Note EGD has a 2006 rate case. Regulatory stability has improved after a recent spate of decisions & PBR is possible. Mainline negotiated ITS is complete and is neutral to slightly positive from a credit perspective. For **Alliance**, we like the "structuring premium" of an amortizer and the simplicity of this credit; not affected by how the ownership is structured; valuation reflects the defensive nature of this credit. It continues to perform as expected. Mgt turnover has been signficant (CFO earlier and now CEO) but this has no credit impact either for this contractually structured credit															
TransCanada	KY	A	A2	A- Neg	Stable but event risk	Medium	F	6.05% 2007	1.94%	6.5% 2030	9.36%	30	▼ 6	115	↔ 0
Negative outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand. We think that short-term acquisition risk is reduced with the announced sale of TransCanada Power LP interests to EPCOR, which should improve TRP's cash outlook w and balance sheet capacity when the transaction closes. Management's commitment to maintain TRP's "A" rating also mitigates short-term risks associated with acquisitions. We read this to mean that TRP will likely make acquisitions in a conservative way (ce sheet not be a detriment to bondholders). The improved balance sheet and renewed commitment to its "A" rating gives us more comfort that TRP's credit quality may not deteriorate if it were to make a large acquisition in the near-term.															
Duke (Westcoast)	KY	A(low) UR-Dev	NR	BBB CW-Neg	Improving	Low	R	5.7% 2008	2.74%	7.15% 2031	8.29%	38	▼ 8	131	▲ 8
Duke (Union Gas)	KY	A UR-Dev	NR	BBB CW-Neg	Standalone stbl + DUK effect	Low	R	5.7% 2008	2.67%	8.65% 2025	7.85%	36	▼ 5	118	▲ 4
MNEP	KY	A	A1 UR-PD	A	Strong	Very low	F	NA	NA	6.9% 2019	6.57%	NA	NA	63	▼ 17
The announced merger with Cinergy should take some of the growth pressures off management, which is good for bondholders. Also good for bondholders in that this is an all stock deal and Cinergy's merchant assets (which is mostly coal) should diversify thenounce risks. Although S&P agrees with us that the transaction in itself is not a detriment to credit, it nevertheless put Duke on credit watch negative because of the uncertainty with regards to what Duke mgmt may do post merger - namely possibility of separatiS&P agrees with and unregulated utilities. We believe the separation of the regulated and unregulated businesses may actually be good for credit ratings of Westcoast and Union Gas. However, in the event that nothing happens post merger and Duke remains whole, as it is nunre ratings of Westcoast and Union Gas should remain unchanged. Of greater concern should be the talk of spinning out the Westcoast assets into an income trust, which we believe could be a mild negative (depending on how the trust is structured) for Westcoasta bondholders. Union Gas for now is not expected to be put into an income trust. For MNEP, we like structural protection and simplicity; valuation reflects the defensive nature of this credit.															
Terasen	KY	A(low)	A3	BBB-	Stable but some event risk	Low	F	6.3% 2008	3.13%	NA	NA	46	▼ 12	NA	NA
Terasen Gas	KY	A	A2	BBB	Stable	Low	F	NA	NA	6.95% 2029	10.74%	NA	NA	118	▼ 11
Business fundamentals are a strong combination of a regulated gas distribution and pipelines, with aggressive financial profile. Although to be fair, we note that most of TER's consolidated debt resides at INL, which is a regulated utility that is restricts are a strong combi equity it can have in its capital structure by the BCUC. BCUC's allowed equity cushion for gas utilities is among the lowest in Canada. We also like the relatively conservative near-term growth of TER, with most of the growth focused on adding to regulatn have in it With ENB getting a new ITS, attention now is on Trans Mountain's ITS. We think that Trans Mountain's ROE will fall but not back to the allowed ROE. Producers will likely give Trans Mountain chances to make up most of the rebased earnings with incentives.B getti new ITS will have greater impact on TER's consolidated cash flow and credit metrics because all of Trans Mountain is under the current ITS.															
Integrated electric: *A mixed bag of companies, ranging from trasnmission dominated, through fully integrated but in a regulated setting, to a mix of regulated T&D and non-regualated generation, and even E&P. Hence risk profiles vary and the companies in this group are not direct comparables.*															
Emera	KY	BBB(high)	Baa2	BBB+ Neg	May weaken	Medium	R	NA	NA	NA	NA	NA	NA	NA	NA
Nova Scotia Power	KY	A(low)	Baa1	BBB+ Neg	May weaken	Medium	R	5.55% 2009	3.46%	8.85% 2025	8.78%	43	▼ 5	130	▲ 1
The negative regulatory decision for NSP that disallowed fuel adjustment clause and granted lower allowed ROE than anticipated is a negative for credit and may lead to increase rating risk. The potential negative cash flow impact of this decision means th regulatory increased risk that Emera will not be able to hit the credit metric targets that S&P has set for the company. Furthermore, the negative decision underscores the fact that NSP's relationship with its regulator has taken a step backwards rather than our expthat Emera will this relationship would improve. NSP recently filed 2006 rate case seeking 15% increase in rates in order to recover significant increase in fuel expense. We don't think that they will get the full amount, which puts NSP's cash flow and credit metrics atuld improve. NSP issuer here is really NSP, but even it has scarcity value.															
EPCOR	KY	A(low)	NR	BBB+	Stable	Low	R	6.2% 2008	2.96%	6.8% 2029	11.11%	37	▼ 10	118	▼ 9
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or write to CIBC World Markets Inc. BCE Place, 161 Bay Street, 4th Floor, Toronto, Ontario M5J 2S8, Attention: Research Disclosures Request.

Our Ratings

Market Perform	The issuer's bonds are expected to perform in line with our universe of bonds over the next 12 months
Outperform	The issuer's bonds are expected to outperform our universe of bonds over the next 12 months.
Underperform	The issuer's bonds are expected to underperform our universe of bonds over the next 12 months

Rating Category	CIBC WM - CDR Universe (equally weighted)
Outperform	38%
Market Perform	46%
Underperform	15%

Tuesday, August 02, 2005

CIBCWM Bond Rating:

Market Perform

Credit Ratings: Terasen Inc.

S&P: BBB-/Stable

Moody's: A3/Stable

DBRS: A (low)/Stable

Credit Ratings: Terasen Gas

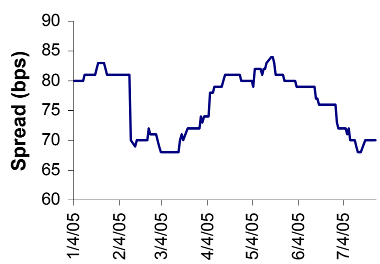
S&P: BBB/Stable

Moody's: A2/Stable

DBRS: A/Stable

Bond Spreads

TER 5.56% 9/15/2014



Source: CIBC World Markets

Kevin Yong

416-956-6273
kevin.yong@cibc.ca

Joanna Zapior

416-594-8498
joanna.zapior@cibc.ca

Pipelines & Utilities

Terasen Inc.

Kinder Morgan to acquire Terasen Inc.

CREDIT IMPACT: Neutral. **From a credit perspective we continue to think that this transaction should be neutral for Terasen bondholders** since most of the Terasen operating company (opco) bonds will likely remain at the opcos and the opcos will likely retain the current operating autonomy that they now enjoy. So in effect other than a change of parent ownership, there should be no fundamental changes to the bonds of Terasen opcos. **There may be some rating volatility due to the transaction and given the difference between Terasen opco ratings and Kinder Morgan Inc. (BBB rated with one positive outlook) ratings. We think that it is reasonable to assume that Terasen Inc. and Terasen opco ratings in the "A" category may be at risk.** As we go to print, Moody's placed Terasen Inc and Terasen Gas senior unsecured ratings under review for possible downgrade. If Terasen Inc and Terasen Gas ratings were to get downgraded (Moody's and DBRS), then we should expect to see some softness in spreads. At this point though, **given the scarcity value of Terasen bonds, strong demand for utility bonds, and the fact that nothing fundamentally has changed, we will maintain our Market Perform rating on Terasen Inc. and Terasen Gas bonds.** Terasen Inc. and Terasen Gas bond spreads have been resilient today with spreads unchanged to a touch wider this morning.

Conference call highlights:

- **All current opco level debt will remain at the opco level** – this means that all bonds of Terasen Gas, Terasen Gas Vancouver Island, Terasen Pipelines (Trans Mountain), and Terasen Pipelines (Corridor) will remain at the opco level. See previous comment for Terasen corporate structure and capital structure.
- **Opcos will retain current operating autonomy according to Kinder Morgan Inc. (KMI) management on the conference call** – KMI management specifically mentioned that Terasen Gas is a stand-alone operating company and will continue to operate that way post acquisition.
- **Current Terasen holdco may be replaced with a new wholly owned Canadian subsidiary of KMI** – management said on the conference call that KMI will establish a wholly owned Canadian subsidiary to hold all of Terasen's opcos. On a follow-up call to KMI, we confirmed that current plan is for this new Canadian subsidiary of KMI to replace the existing Terasen Inc. holdco. **What is uncertain is whether or not the three bond issues currently at Terasen Inc. (i.e. 6.3% 2008, 4.85% 2006, and 5.56% 2014) will be held by the new subsidiary or will be consolidated as KMI bonds.** At the time of our telephone conversation, KMI's investor relations were not able to give us a definitive answer to this question.

- **KMI will have to finance this acquisition with about US$2 billion in debt –** which KMI expects to financed with a bridge facility and then terming this facility out with a long-term bond issue. Management said that the **current plan calls for the new Canadian subsidiary to issue public bonds to repay the bridge facility upon closing of the transaction.** The uncertainty (again KMI investor relations could not shed any light on this on the phone) is in what market KMI will issue the new bonds. It may be a C$ bond issue, or a US$ bond issue, or it may be a combination of both. Additionally, future debt financing for growth projects of the Canadian assets will be issued from this new subsidiary. If the entire amount is issued in Canada at once, then we may see spread weakness.

- **Ratings may be at risk –** both KMI and Terasen have talked to the rating agencies about the transaction. Terasen said that the rating agencies have all the details of the transaction, including the plan to maintain debt at the opco level and operating autonomy of the opcos. Given the big difference in ratings between KMI and Terasen, it would not be a surprise to see a rating agency like Moody's downgrading the ratings of Terasen opco bonds in order to close the ratings gap between KMI and Terasen.

- **KMI likes gas LDC business and cannot roll these assets down to its MLP –** KMI management said that it likes Terasen's gas LDCs (Terasen Gas and Terasen Gas Vancouver Island) and expects to keep these natural gas LDCs rather than selling them. KMI is also legally not able to roll these assets down into its MLP (Kinder Morgan Energy Partners, which BBB+ rated, is a publicly traded master limited partnership), as gas distribution businesses are excluded from MLP qualified business activities.

- **Canadian pipeline assets not tax efficient for MLP roll-down –** management said that it would not be tax efficient for KMI to roll-down Terasen's Canadian pipeline assets into its MLP. The reason is that these Canadian assets still have to pay Canadian taxes even if they were in a U.S. MLP. That said though, management did not rule out putting the U.S. portion of Express and Platte into KMI's MLP. Also, management said that income trust for the Canadian pipeline assets is another option but that it was too early to say definitively what their plans will be for the Canadian pipeline assets.

- **Future growth plans in Canada –** KMI's growth plans in Canada will likely be focused on pipeline expansions, terminal expansions in Alberta, and potential growth of a CO_2 pipeline in Alberta. Management said that outside of steady organic growth, it does not have big growth plans for Terasen's gas distribution businesses.

Please refer to Our Opinions table (below) to place this credit in its sector-relative-value context

26-Jul-05	Analyst	Senior unsecured DBRS	Senior unsecured Moody's	Senior unsecured S&P	Credit fundamentals (1-3 years)	Rating change probab. (1 year)	Valuation	YTD total return: Shorter bond – Bond	Shorter bond – Return	Longer bond – Bond	Longer bond – Return	YTD change in spread: Shorter bond – Curr Sprd	Shorter bond – YTD Chng	Longer bond – Curr Sprd	Longer bond – YTD Chng

Pipelines: *Solid, largely regulated fundamentals, though regulatory environment disadvantages those companies that have North American growth plans as Cdn leverage is higher and returns lower. Our investment thesis rests on two pillars: 1) operating excellence and cost management will be key in light of 2) regulators pressuring for cost control, including returns. Holding company risk has been increasing with expansion in non-regulated areas, equity market push for growth, and still elevated leverage.*

Gas distribution: *Stable sector, with strong operating franchises and good fundamentals. However, no standalone credits left (exceptand credit quality is affected by parent activities. See also our comment on the pipeline sector.*

Issuer	Analyst	DBRS	Moody's	S&P	Credit fundamentals	Rating change probab.	Valuation	Bond	Return	Bond	Return	Curr Sprd	YTD Chng	Curr Sprd	YTD Chng
Enbridge Inc	KY	A	A3	A-	May weaken (M&A, projects)	Medium	C	5.8% 2008	2.59%	8.2% 2024	8.73%	32	▼ 4	90	▼ 11
Enbridge Pipelines	KY	A(high)	NR	A-	Stable	Medium	R	5.621% 2007	1.86%	7.2% 2032	10.70%	29	▼ 1	116	▼ 9
Enbridge Gas Dist.	KY	A	NR	A-	Stable	Medium	R	11.15% 2009	2.96%	6.1% 2028	9.77%	55	▲ 4	95	▼ 6
Alliance Pipe	KY	A(low)	A3	BBB+	Strong	Very low	F	7.23% 2015	4.76%	7.217% 2025	5.82%	36	▼ 27	91	▼ 8

There are continued M&A and large project risks - lots of noise in the news as jockeying for positions continues. The market now prices its uncertainty about committment to "A" ratings. Pipe acquisition in the GoM has eroded current balance sheet to the lecontinued permissible under the S&P rating. Over time, we see balance sheet quality potentially weakening as more risky assets may be added while mature, stable assets end up in income trust. That it has historically been a defensive credit (low spread volatility) under the pause but history may not repeat itself. We view **opcos** as better credits in line with DBRS logic but not necessarily better value. Note **EGD** has a 2006 rate case. Regulatory stability has improved after a recent spate of decisions & PBR is possible. Mainline negotiated ITS is complete and is neutral to slightly positive from a credit perspective. For **Alliance,** we like the "structuring premium" of an amortizer and the simplicity of this credit; not affected by how the ownership is structured; valuation reflects the defensive nature of this credit. It continues to perform as expected. Mgt turnover has been signficant (CFO earlier and now CEO) but this has no credit impact either for this contractually structured credit

Issuer	Analyst	DBRS	Moody's	S&P	Credit fundamentals	Rating change probab.	Valuation	Bond	Return	Bond	Return	Curr Sprd	YTD Chng	Curr Sprd	YTD Chng
TransCanada	KY	A	A2	A- Neg	Stable but event risk	Medium	F	6.05% 2007	1.94%	6.5% 2030	9.36%	30	▼ 6	115	↔ 0

Negative outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand. We think that short-term acquisition risk is reduced with the announced sale of TransCanada Power LP interests to EPCOR, which should improve TRP's cash outlook w and balance sheet capacity when the transaction closes. Management's commitment to maintain TRP's "A" rating also mitigates short-term risks associated with acquisitions. We read this to mean that TRP will likely make acquisitions in a conservative way (ce sheet not be a detriment to bondholders). The improved balance sheet and renewed commitment to its "A" rating gives us more comfort that TRP's credit quality may not deteriorate if it were to make a large acquisition in the near-term.

Issuer	Analyst	DBRS	Moody's	S&P	Credit fundamentals	Rating change probab.	Valuation	Bond	Return	Bond	Return	Curr Sprd	YTD Chng	Curr Sprd	YTD Chng
Duke (Westcoast)	KY	A(low) UR-Dev	NR	BBB CW-Neg	Improving	Low	R	5.7% 2008	2.74%	7.15% 2031	8.29%	38	▼ 8	131	▲ 8
Duke (Union Gas)	KY	A UR-Dev	NR	BBB CW-Neg	Standalone stbl + DUK effect	Low	R	5.7% 2008	2.67%	8.65% 2025	7.85%	36	▼ 5	118	▲ 4
MNEP	KY	A	A1 UR-PD	A	Strong	Very low	F	NA	NA	6.9% 2019	6.57%	NA	NA	63	▼ 17

The announced merger with Cinergy should take some of the growth pressures off management, which is good for bondholders. Also good for bondholders in that this is an all stock deal and Cinergy's merchant assets (which is mostly coal) should diversify thenounce risks. Although S&P agrees with us that the transaction in itself is not a detriment to credit, it nevertheless put Duke on credit watch negative because of the uncertainty with regards to what Duke mgmt may do post merger - namely possibility of separatiS&P agrees with and unregulated utilities. We believe the separation of the regulated and unregulated businesses may actually be good for credit ratings of Westcoast and Union Gas. However, in the event that nothing happens post merger and Duke remains whole, as it is nunre ratings of Westcoast and Union Gas should remain unchanged. Of greater concern should be the talk of spinning out the Westcoast assets into an income trust, which we believe could be a mild negative (depending on how the trust is structured) for Westcoasta bondholders. Union Gas for now is not expected to be put into an income trust. For **MNEP**, we like structural protection and simplicity; valuation reflects the defensive nature of this credit.

Issuer	Analyst	DBRS	Moody's	S&P	Credit fundamentals	Rating change probab.	Valuation	Bond	Return	Bond	Return	Curr Sprd	YTD Chng	Curr Sprd	YTD Chng
Terasen	KY	A(low)	A3	BBB-	Stable but some event risk	Low	F	6.3% 2008	3.13%	NA	NA	46	▼ 12	NA	NA
Terasen Gas	KY	A	A2	BBB	Stable	Low	F	NA	NA	6.95% 2029	10.74%	NA	NA	118	▼ 11

Business fundamentals are a strong combination of a regulated gas distribution and pipelines, with aggressive financial profile. Although to be fair, we note that most of TER's consolidated debt resides at INL, which is a regulated utility that is restricts are a strong combi equity it can have in its capital structure by the BCUC. BCUC's allowed equity cushion for gas utilities is among the lowest in Canada. We also like the relatively conservative near-term growth of TER, with most of the growth focused on adding to regulatn have in it With ENB getting a new ITS, attention now is on Trans Mountain's ITS. We think that Trans Mountain's ROE will fall but not back to the allowed ROE. Producers will likely give Trans Mountain chances to make up most of the rebased earnings with incentives.B getti new ITS will have greater impact on TER's consolidated cash flow and credit metrics because all of Trans Mountain is under the current ITS.

Integrated electric: *A mixed bag of companies, ranging from trasnmission dominated, through fully integrated but in a regulated setting, to a mix of regulated T&D and non-regualated generation, and even E&P. Hence risk profiles vary and the companies in this group are not direct comparables.*

Issuer	Analyst	DBRS	Moody's	S&P	Credit fundamentals	Rating change probab.	Valuation	Bond	Return	Bond	Return	Curr Sprd	YTD Chng	Curr Sprd	YTD Chng
Emera	KY	BBB(high)	Baa2	BBB+ Neg	May weaken	Medium	R	NA	NA	NA	NA	NA	NA	NA	NA
Nova Scotia Power	KY	A(low)	Baa1	BBB+ Neg	May weaken	Medium	R	5.55% 2009	3.46%	8.85% 2025	8.78%	43	▼ 5	130	▲ 1

The negative regulatory decision for NSP that disallowed fuel adjustment clause and granted lower allowed ROE than anticipated is a negative for credit and may lead to increase rating risk. The potential negative cash flow impact of this decision means th regulatory increased risk that Emera will not be able to hit the credit metric targets that S&P has set for the company. Furthermore, the negative decision underscores the fact that NSP's relationship with its regulator has taken a step backwards rather than our expthat Emera will this relationship would improve. NSP recently filed 2006 rate case seeking 15% increase in rates in order to recover significant increase in fuel expense. We don't think that they will get the full amount, which puts NSP's cash flow and credit metrics atuld improve. NSP issuer here is really NSP, but even it has scarcity value.

Issuer	Analyst	DBRS	Moody's	S&P	Credit fundamentals	Rating change probab.	Valuation	Bond	Return	Bond	Return	Curr Sprd	YTD Chng	Curr Sprd	YTD Chng
EPCOR	KY	A(low)	NR	BBB+	Stable	Low	R	6.2% 2008	2.96%	6.8% 2029	11.11%	37	▼ 10	118	▼ 9

Credit fundamentals (i.e. credit metrics and tighter management) and lack of liquidity in the bond are positive for spreads. EPCOR's strong credit fundamentals is founded on its relatively low-risk business profile and a very strong balance sheet (end of 1s (i.e. credit met these positives are continued soft electricity market in Alberta, increased merchant exposure, and event risk related to renewed focus on growth. We see EPCOR's recent acquisiton of TransCanada's interest in TransCanada Power LP as neutral for bondholderse po these assets are bondholder-friendly and this acquisition was small enough to not have a material negative impact on EPCOR's balance sheet in 2005. The risk here is that management may not be done with growth yet.

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Our Ratings

Market Perform The issuer's bonds are expected to perform in line with our universe of bonds over the next 12 months

Outperform The issuer's bonds are expected to outperform our universe of bonds over the next 12 months.

Underperform The issuer's bonds are expected to underperform our universe of bonds over the next 12 months

Rating Category	CIBC WM - CDR Universe (equally weighted)
Outperform	38%
Market Perform	46%
Underperform	15%

CIBC World Markets

Corporate Debt Research
Credit Comment

research.cibcwm.com/res/Crp/CrpResearch.html

Tuesday, August 02, 2005

CIBCWM Bond Rating:

Market Perform

Credit Ratings: Terasen Inc.

S&P: BBB-/Stable

Moody's: A3/Stable

DBRS: A (low)/Stable

Credit Ratings: Terasen Gas

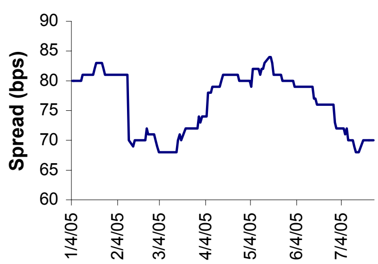
S&P: BBB/Stable

Moody's: A2/Stable

DBRS: A/Stable

Bond Spreads

TER 5.56% 9/15/2014



Source: CIBC World Markets

Kevin Yong

416-956-6273
kevin.yong@cibc.ca

Joanna Zapior

416-594-8498
joanna.zapior@cibc.ca

Pipelines & Utilities

Terasen Inc.

Kinder Morgan to acquire Terasen Inc.

OUR INITIAL TAKE: Negative from a ratings perspective but neutral from a credit perspective. Kinder Morgan (KMI) is rated BBB/stable by S&P, Moody's, and DBRS, and Fitch rates KMI BBB/Positive. From a credit perspective, KMI has lower leverage and higher coverage ratios than Terasen. Although, KMI has a better financial profile than Terasen, its business risk profile is higher risk than Terasen's. As such, we think that the better financial risk profile is offset by the higher risk profile of KMI and this transaction should be credit neutral.

- **KMI has a better financial profile than Terasen** – KMI ended 2004 with a debt to capital of about 43%, total debt to cash flow of 5x, and EBIT coverage of about 5.6x. By comparison, Terasen ended 2004 with a debt to capital of 68%, total debt to cash flow of almost 10x, and EBIT coverage of 2.4x.
- **KMI has a higher risk business profile than Terasen** – KMI operates predominantly regulated and fee-based energy infrastructure businesses in the U.S. Rocky Mountains and mid-continent regions of the U.S. KMI's assets consists of Natural Gas Pipeline Company of America (which is the largest transporter of natural gas in the Chicago area), small retail natural gas distribution, power assets, and ownership in Kinder Morgan Energy Partners, L.P. (a publicly traded master limited partnership that owns and operates a diverse portfolio of largely fee-based pipelines and midstream energy assets.
- **KMI has high management ownership** – KMI is 23% owned by management.

Details of the transaction:

- KMI proposes to acquire all common shares and assume all debt of Terasen Inc.
- Annual dividend of KMI is expected to rise US$3.50 in 2006 from a current dividend of US$3.00. This is significant as KMI's high payout ratio is a credit concern.
- Upon closing of the transaction the total debt to capital ratio of KMI is expected by management to increase to about 56%. Management expects that KMI will be able to retain its BBB rating upon closing of the transaction.
- Transaction will require the approval of 75% of Terasen shareholders, who will vote at a special meeting to be held on or before October 31, 2005.
- KMI is offering to acquire Terasen for C$35.91 per share, which represents a 14% premium on Friday's closing price. The offer is for a combination of shares and cash (65% cash and 35% shares).
- Terasen has an agreed to a break-fee of C$75 million.
- Terasen conference call at 10 AM at 1-877-375-5688. KMI has a conference call at 8 AM (web cast at www.kindermorgan.com).

Trevor Bateman, CFA, CA	Phillip Armstrong	Kevin Yong, CFA	Joanna Zapior, CFA, CMC
(416) 594-7992	(416) 956-3272	(416) 956-6273	(416) 594-8498
Banks, Non-bank financials, Autos, ABS	Telecom, Cable, Insurance, Retail, Consumer Products	Oil & Gas, Utilities, Aerospace	Strategy

Dina Giacomelli –Editor **(416) 956-6056**

CIBC World Markets Inc. PO Box 500, 161 Bay Street, BCE Place, Toronto, Canada M5J 2S8 Bloomberg@wgec1 **(416) 594-7000**
CIBC World Markets Corp. 300 Madison Avenue, New York, NY 10017 **(212) 856-4000, (800) 999-6726**

Please refer to Our Opinions table (below) to place this credit in its sector-relative-value context

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There are continued M&A and large project risks - lots of noise in the news as jockeying for positions continues. The market now prices its uncertainty about committment to "A" ratings. Pipe acquisition in the GoM has eroded current balance sheet to the lecontinued permissible under the S&P rating. Over time, we see balance sheet quality potentially weakening as more risky assets may be added while mature, stable assets end up in income trust. That it has historically been a defensive credit (low spread volatility) under the pause but history may not repeat itself. We view **opcos** as better credits in line with DBRS logic but not necessarily better value. Note **EGD** has a 2006 rate case. Regulatory stability has improved after a recent spate of decisions & PBR is possible. Mainline negotiated ITS is complete and is neutral to slightly positive from a credit perspective. For **Alliance,** we like the "structuring premium" of an amortizer and the simplicity of this credit; not affected by how the ownership is structured; valuation reflects the defensive nature of this credit. It continues to perform as expected. Mgt turnover has been signficant (CFO earlier and now CEO) but this has no credit impact either for this contractually structured credit															
TransCanada	KY	A	A2	A- Neg	Stable but event risk	Medium	F	6.05% 2007	1.94%	6.5% 2030	9.36%	30	▼ 6	115	⇔ 0
Negative outlook will take a long time to hatch, if at all - unless an acquisition forces S&P's hand. We think that short-term acquisition risk is reduced with the announced sale of TransCanada Power LP interests to EPCOR, which should improve TRP's cash outlook w and balance sheet capacity when the transaction closes. Management's commitment to maintain TRP's "A" rating also mitigates short-term risks associated with acquisitions. We read this to mean that TRP will likely make acquisitions in a conservative way (ce sheet not be a detriment to bondholders). The improved balance sheet and renewed commitment to its "A" rating gives us more comfort that TRP's credit quality may not deteriorate if it were to make a large acquisition in the near-term.															
Duke (Westcoast)	KY	A(low) UR-Dev	NR	BBB CW-Neg	Improving	Low	R	5.7% 2008	2.74%	7.15% 2031	8.29%	38	▼ 8	131	▲ 8
Duke (Union Gas)	KY	A UR-Dev	NR	BBB CW-Neg	Standalone stbl + DUK effect	Low	R	5.7% 2008	2.67%	8.65% 2025	7.85%	36	▼ 5	118	▲ 4
MNEP	KY	A	A1 UR-PD	A	Strong	Very low	F	NA	NA	6.9% 2019	6.57%	NA	NA	63	▼ 17
The announced merger with Cinergy should take some of the growth pressures off management, which is good for bondholders. Also good for bondholders in that this is an all stock deal and Cinergy's merchant assets (which is mostly coal) should diversify thenounce risks. Although S&P agrees with us that the transaction in itself is not a detriment to credit, it nevertheless put Duke on credit watch negative because of the uncertainty with regards to what Duke mgmt may do post merger - namely possibility of separatiS&P agrees with and unregulated utilities. We believe the separation of the regulated and unregulated businesses may actually be good for credit ratings of Westcoast and Union Gas. However, in the event that nothing happens post merger and Duke remains whole, as it is nunre ratings of Westcoast and Union Gas should remain unchanged. Of greater concern should be the talk of spinning out the Westcoast assets into an income trust, which we believe could be a mild negative (depending on how the trust is structured) for Westcoasta bondholders. Union Gas for now is not expected to be put into an income trust. For **MNEP**, we like structural protection and simplicity; valuation reflects the defensive nature of this credit.															
Terasen	KY	A(low)	A3	BBB-	Stable but some event risk	Low	F	6.3% 2008	3.13%	NA	NA	46	▼ 12	NA	NA
Terasen Gas	KY	A	A2	BBB	Stable	Low	F	NA	NA	6.95% 2029	10.74%	NA	NA	118	▼ 11
Business fundamentals are a strong combination of a regulated gas distribution and pipelines, with aggressive financial profile. Although to be fair, we note that most of TER's consolidated debt resides at INL, which is a regulated utility that is restricts are a strong combi equity it can have in its capital structure by the BCUC. BCUC's allowed equity cushion for gas utilities is among the lowest in Canada. We also like the relatively conservative near-term growth of TER, with most of the growth focused on adding to regulatn have in it With ENB getting a new ITS, attention now is on Trans Mountain's ITS. We think that Trans Mountain's ROE will fall but not back to the allowed ROE. Producers will likely give Trans Mountain chances to make up most of the rebased earnings with incentives.B getti new ITS will have greater impact on TER's consolidated cash flow and credit metrics because all of Trans Mountain is under the current ITS.															
Integrated electric: *A mixed bag of companies, ranging from trasnmission dominated, through fully integrated but in a regulated setting, to a mix of regulated T&D and non-regualated generation, and even E&P. Hence risk profiles vary and the companies in this group are not direct comparables.*															
Emera	KY	BBB(high)	Baa2	BBB+ Neg	May weaken	Medium	R	NA	NA	NA	NA	NA	NA	NA	NA
Nova Scotia Power	KY	A(low)	Baa1	BBB+ Neg	May weaken	Medium	R	5.55% 2009	3.46%	8.85% 2025	8.78%	43	▼ 5	130	▲ 1
The negative regulatory decision for NSP that disallowed fuel adjustment clause and granted lower allowed ROE than anticipated is a negative for credit and may lead to increase rating risk. The potential negative cash flow impact of this decision means th regulatory increased risk that Emera will not be able to hit the credit metric targets that S&P has set for the company. Furthermore, the negative decision underscores the fact that NSP's relationship with its regulator has taken a step backwards rather than our expthat Emera will this relationship would improve. NSP recently filed 2006 rate case seeking 15% increase in rates in order to recover significant increase in fuel expense. We don't think that they will get the full amount, which puts NSP's cash flow and credit metrics atuld improve. NSP issuer here is really NSP, but even it has scarcity value.															
EPCOR	KY	A(low)	NR	BBB+	Stable	Low	R	6.2% 2008	2.96%	6.8% 2029	11.11%	37	▼ 10	118	▼ 9
Credit fundamentals (i.e. credit metrics and tighter management) and lack of liquidity in the bond are positive for spreads. EPCOR's strong credit fundamentals is founded on its relatively low-risk business profile and a very strong balance sheet (end of 1s (i.e. credit met these positives are continued soft electricity market in Alberta, increased merchant exposure, and event risk related to renewed focus on growth. We see EPCOR's recent acquisiton of TransCanada's interest in TransCanada Power LP as neutral for bondholderse po these assets are bondholder-friendly and this acquisition was small enough to not have a material negative impact on EPCOR's balance sheet in 2005. The risk here is that management may not be done with growth yet.															

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Outperform The issuer's bonds are expected to outperform our universe of bonds over the next 12 months.

Underperform The issuer's bonds are expected to underperform our universe of bonds over the next 12 months

Rating Category	CIBC WM - CDR Universe (equally weighted)
Outperform	38%
Market Perform	46%
Underperform	15%

CIBC World Markets

Equity Research
Industry Update

August 02, 2005

Pipelines, Utilities, & Power

Sector Weighting:

Market Weight

TER Takeout Valuation Would Boost Other Pipes & Utes

Biggest Potential Upside in TRP, FTS, TA

- Kinder Morgan's acquisition of Terasen establishes utility valuation metrics that are higher than we have seen in the past. Most other Canadian pipelines and utilities are still trading at significant discounts to the Terasen acquisition multiple.
- We have analyzed potential share price appreciation in several of the Canadian stocks based on the 24x P/E and 11.5x EBITDA multiple KMI is paying for TER.
- We find the most upside potential in TransCanada, Fortis and TransAlta. Emera and Canadian Utilities would have some upside but we see ownership restrictions in both that would likely prevent a takeover.
- Canadian pipeline and utility companies could just as easily be buyers as sellers. In the current investing environment both buyers and sellers are moving up on deal announcements. Either way, we believe shareholders are winning as consolidation takes hold.

All figures in Canadian dollars, unless otherwise stated.

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See "Price Target Calculation" and "Key Risks to Price Target" sections at the end of this report, or at the end of each section hereof, where applicable.

Matthew Akman
1 (416) 956-6169
Matthew.Akman@cibc.ca

Alda Pavao, CFA
1 (416) 956-3229
Alda.Pavao@cibc.ca

Investment Summary

Kinder Morgan's (KMI-NYSE, Not Rated) acquisition of Terasen (TER-TSX, Sector Performer) establishes utility valuation metrics that are higher than we have seen in the past. In yesterday's research note we compared the valuation to other recent utility transactions. Most other Canadian pipelines and utilities are still trading at significant discounts to the Terasen acquisition multiple. We have quantified the gap between current valuations and potential takeout valuations for several of the stocks in our coverage universe.

We have analyzed potential share price appreciation in several of the Canadian stocks based on the 24x P/E and 11.5x EBITDA multiple KMI is paying for TER. Currently, the Canadian pipelines and utilities are trading at the much lower metrics of about 19x earnings and 9x EBITDA.

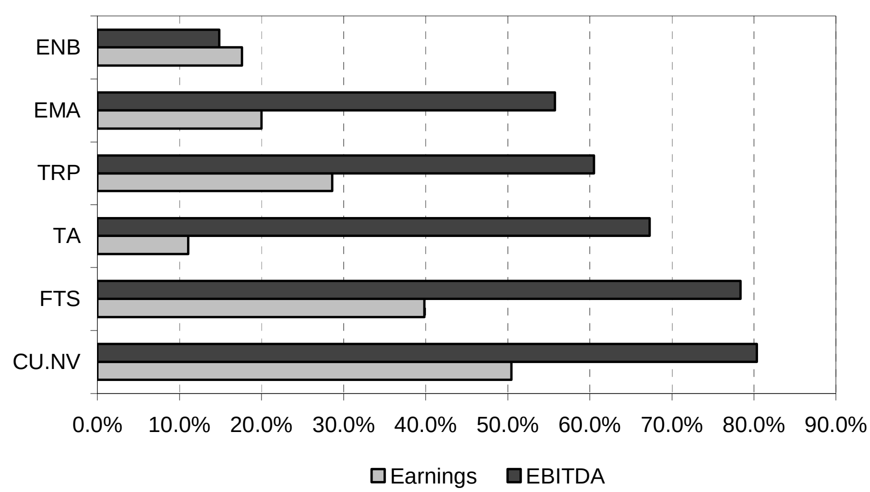
Exhibit 1. Comparative Valuation of Canadian Pipeline, Power and Utility Companies

			Share Price		Earnings per Share		P/E (x)		Cash Flow per Share		P/CF (x)		Book	EV/
Company Name	Ticker	Rating	2-Aug-05	Yield	2005E	2006E	2005E	2006E	2005E	2006E	2005E	2006E	Value	2006E EBITDA
Enbridge Inc.	ENB	SP	$35.99	2.8%	$1.63	$1.73	22.1	20.8	$3.30	$3.37	10.9	10.7	3.0	10.6
TransCanada Corp.	TRP	SO	$33.50	3.6%	$1.65	$1.80	20.3	18.6	$3.85	$3.97	8.7	8.4	2.4	8.6
TransAlta Corp.	TA	SP	$21.93	4.6%	$0.75	$1.00	29.2	21.9	$3.25	$3.48	6.7	6.3	1.7	8.4
Fortis	FTS	SO	$84.45	2.7%	$4.55	$4.80	18.6	17.6	$12.08	$11.86	7.0	7.1	1.9	8.5
Emera	EMA	SU	$17.94	5.0%	$0.80	$0.90	22.4	19.9	$2.45	$2.60	7.3	6.9	1.4	9.0
Canadian Utilities	CU.NV	SP	$73.55	3.0%	$4.20	$4.55	17.5	16.2	$9.19	$9.49	8.0	7.8	2.1	7.9
Average							***21.7***	***19.2***			***8.1***	***7.9***	***2.1***	***8.9***

Source: Company reports and CIBC World Markets Inc.

Valuation expansion to the Terasen takeout multiples would drive significant share price appreciation for the Canadian pipelines and utilities. Moving up to the 24x P/E multiple would require anywhere from a 18% to 50% increase in share prices. Moving up to the 11.5x EBITDA multiple would require anywhere from about 15% to 80% increase in share prices.

Exhibit 2. Hypothetical Upside Potential to Current Share Prices



Note: We applied Terasen's takeout earnings and EBITDA multiples to our 2006 estimates.

Source: Company reports and CIBC World Markets Inc.

CIBC World Markets

Several general and specific observations flow from our calculations:

- Most of the stocks show more upside to the acquisition EBITDA multiple than the acquisition P/E multiple. The ability to pay 11.5x EBITDA for a utility stock was unique and probably relates to the stability of cash flows from Terasen's 100% regulated pipeline and utility business.

- Enbridge (ENB-TSX, Sector Performer) shows the least upside to the Terasen acquisition multiple because it trades at a premium to the group. The market has appropriately already recognized much of the strategic value in the Enbridge asset base.

- TransAlta (TA-TSX, Sector Performer) has little upside to the 24x earnings multiple because its earnings are currently depressed while it operates under legacy contracts to sell power below market prices. We see upside to earnings in the 2007–2009 timeframe that would tend to reduce the stock's P/E multiple.

In summary, TransCanada (TRP-TSX, Sector Outperformer), Fortis (FTS-TSX, Sector Outperformer) and TransAlta show the biggest gaps between current valuation metrics and the Terasen takeout multiple. Emera (EMA-TSX, Sector Underperformer) and Canadian Utilities (CU.NV-TSX, Sector Performer) would have some upside but we see ownership restrictions in both that would likely prevent a takeover. Canadian Utilities is family controlled. Emera still has provisions that prevent concentration in voting shares of more than 15% and concentration of foreign holding of more than 25%.

Predicting M&A activity is difficult and the Terasen deal may be a one off. In fact, Canadian pipeline and utility companies could just as easily be buyers as sellers. However, in the current investing environment, the shares of both buyers and sellers are moving up on deal announcements. Either way, we believe shareholders are winning as consolidation takes hold.

Price Target Calculations

Our price targets for the pipeline and utility companies are derived from P/E multiples and dividend yields (relative to bond yields) primarily based on our 2006 earnings and dividend forecasts. We also consider our outlooks for the stocks beyond 2006. Our target dividend yields range from 3.1%–6.2% (based on a forecast 10-year Canada bond yield of about 4%).

Our target P/E multiples range from 16.4x–23x. This range is at the high end of the historical norm due to historically low bond yields. In the past 15 years, the stocks have tended to peak at no more than 17x–18x earnings, but have traded through those levels recently. The differences in target multiples between stocks under our coverage reflect different organic growth rates, potential acquisition activity, and current regulatory environment.

Key Risks To Price Targets

The main risk to our target prices is unanticipated changes in long bond yields. The correlation between bond yields and utility valuations has been high in recent years. If bond yields rise significantly, valuations across the group are likely to compress. Our target prices are based on 10-Year Canada Bond yield of about 4.0%.

For individual companies, risks to target prices relate primarily to negative regulatory decisions that reduce returns on regulated assets, low acquisition activity, and unanticipated weakness in power prices.

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Enbridge Inc. (2a, 2c, 2e, 2g, 7) (ENB-TSX, C$35.99, Sector Performer)
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S	Suspended	Stock coverage is temporarily halted.
DR	Dropped	Stock coverage is discontinued.
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Sector Underperformer (Sell)	134	16.0%	Sector Underperformer (Sell)	73	54.5%
Restricted	14	1.7%	Restricted	13	92.9%

Ratings Distribution: Pipelines, Utilities, & Power Coverage Universe

(as of 02 Aug 2005)	Count	Percent	Inv. Banking Relationships	Count	Percent
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Sector Performer (Hold/Neutral)	6	54.5%	Sector Performer (Hold/Neutral)	4	66.7%
Sector Underperformer (Sell)	2	18.2%	Sector Underperformer (Sell)	1	50.0%
Restricted	0	0.0%	Restricted	0	0.0%

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August 19, 2005

Pipelines, Utilities, & Power

Sector Weighting:
Market Weight

Kinder Just "Trusted" Terasen: Who's Next?

- Kinder Morgan is using an income trust type structure and paying an income trust premium for Terasen. The other Canadian pipeline and utility corporations must now seek similar valuations if they are available.

- If Kinder Morgan can pay over 11x EBITDA for Terasen, then other industry players or financial buyers may be willing to pay similar multiples for other Canadian companies.

- The Terasen acquisition involves the issuance of debt that significantly reduces income tax liability in both Canada and the U.S. As a result, Canadian regulators will be hard-pressed to block or inhibit the conversion of utility assets into income trust structures.

- In this context, Canadian pipeline and utility companies must explore mergers or further trust conversion to create shareholder value. Given upside to the Terasen takeout multiple, it would be almost irresponsible not to.

All figures in Canadian dollars, unless otherwise stated.

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See "Important Disclosures" section at the end of this report for important required disclosures, including potential conflicts of interest.

See "Price Target Calculation" and "Key Risks to Price Target" sections at the end of this report, or at the end of each section hereof, where applicable.

Matthew Akman
1 (416) 956-6169
Matthew.Akman@cibc.ca

Alda Pavao, CFA
1 (416) 956-3229
Alda.Pavao@cibc.ca

Investment Summary

On August 1, Kinder Morgan (KMI–NYSE, Not Rated) announced the acquisition of Terasen (TER–TSX, Sector Performer) for approximately $35.90 per share. The acquisition price implies an approximately 20% premium and valuation multiples that are much higher than in other recent pipeline and utility transactions. Canadian pipeline and utility share prices have not moved significantly since the acquisition was announced. Yet, the Terasen deal highlights opportunities to unlock value in several of the other Canadian pipeline and utility companies.

How Kinder Morgan, a normally disciplined pipeline company, is going to create shareholder value by paying 23x earnings and 11.8x EBITDA for Terasen is the question most investors and industry observers are now asking. Our take is that Kinder Morgan is effectively turning Terasen into an income trust and realizing the value escalation that normally goes along with a trust conversion. Whether it is through interest deductions or asset transfer into a Master Limited Partnership (MLP), Terasen will pay less income tax and the resulting value will be transferred to shareholders.

Special interest deductions will go a long way to reducing taxable income. Kinder Morgan announced it would issue new debt on the order of US$2.0 billion, funding 53% of the acquired equity value. Interest on this debt will be deductible in Canada and the U.S., reducing the effective cost of debt to about 2% after tax. Kinder Morgan may also transfer some of the Terasen assets into its U.S. MLP — a company that attracts no income tax by design.

Other U.S. companies seeking growth opportunities in Canada have taken notice of Kinder Morgan's methodology and may follow suit. It is always difficult predicting mergers and acquisitions, but large U.S. pipeline and utility companies have often looked toward Canada for growth. The abundance of fossil fuel resources in Alberta and the Arctic will underpin Canadian energy infrastructure growth rates that will likely far exceed growth in the U.S.

If cross-border mergers are not used for reducing tax liability and unlocking value, income trust conversions might be. In the past, regulators have inhibited the conversion of pipeline and utility companies into income trusts. Regulators threatened to offset the benefit of conversion by reducing utility rates when income taxes fell. We now see that threat potentially diminishing.

In the context of the Terasen deal that reduced tax liability via a cross-border structure, Canadian regulators will be hard-pressed to block or inhibit the conversion of utility assets into income trust structures. The Kinder Morgan deal accomplishes the tax arbitrate that a trust would, and leaves the assets in the hands of a U.S. corporation. A Canadian regulatory policy with a bias toward foreign ownership of domestic infrastructure makes no sense. Yet, in preventing trust conversion, Canadian regulators may be unintentionally promoting this exact bias.

Terasen achieved maximum value for its Canadian shareholders. Now the other Canadian pipeline and utility corporations are obligated to seek similar valuations if they are available. Maximizing shareholder value may call for mergers or income trust conversions. The potential valuation upside is significant and has not yet been reflected in the stocks. We count especially TransCanada (TRP–TSX, Sector Outperformer) and Fortis (FTS–TSX, Sector Outperformer) as undervalued on trust/merger multiples. To a lesser extent, we also see upside in Enbridge (ENB–TSX, Sector Performer) and TransAlta (TA–TSX, Sector Performer).

Kinder Is Paying "Trust" Valuation For Terasen

We viewed the takeout valuations on Terasen as expensive based on either trailing or forward financial parameters. When the acquisition was announced, Terasen calculated its takeout valuation metrics of 23.8x earnings and 11.5x EBITDA based on 2005 financial forecasts. Our view is that Terasen has excellent long-term growth prospects but few prospects in 2006. Therefore, our estimated valuation metrics on 2006 financial parameters are similar to the ones Terasen presented based on 2005 parameters.

Terasen's earnings and cash flows will likely not improve much in 2006 because its regulated returns are falling in both the oil pipeline and gas utility business. The lucrative Trans Mountain tolling agreement comes due at the end of this year and the ROE on the gas utilities is reviewed annually. Our 2006 EPS estimate is $1.55, up only $0.05 from our $1.50 forecast in 2005. Similarly, our 2006 EBITDA forecast for Terasen is $585 million, up only $15 million from our $570 million forecast in 2005. Based on these forecasts, we calculate the acquisition multiples as 23x 2006 earnings and 11.8x 2006 EBITDA.

Exhibit 1. TER Takeout Multiples

Deal Parameters			CIBC Forecasts For TER 2005E	2006E
Pro-rata Share Offer Price (C$)	**$35.91**	EPS	$1.50	$1.55
(Based On US$88.86 KMI Share Price)		**Takeout P/E (x)**	**23.9**	**23.2**
Equity Value (C$ mlns.)	$3,790			
Assumption Of Debt And Capital Securities	$3,144	EBITDA (C$ mlns.)	$570	$585
Purchase Price (C$ mlns.)	$6,934	**Takeout EV/EBITDA (x)**	**12.2**	**11.8**

Source: Company reports and CIBC World Markets Inc.

The valuation parameters of the Terasen deal far exceed valuations on the other Canadian pipeline and utility corporations. They are in line or even higher than multiples ascribed to comparable Canadian income trusts. Most of the corporations trade at 8x–9x EBITDA, although some of the pipeline trusts, namely Pembina (PIF.UN–TSX, Sector Performer) and IPL (IPL.UN–TSX, Sector Performer), already attract 11x–12x EBITDA multiples.

Exhibit 2. Comparative Valuation Of Canadian Pipeline, Power And Utility Companies And Trusts

Company Name	Ticker	Rating	Price 08/17/05	Yield	EPS 2005E	EPS 2006E	P/E (x) 2005E	P/E (x) 2006E	Cash Flow Per Share 2005E	Cash Flow Per Share 2006E	P/CF (x) 2005E	P/CF (x) 2006E	Book Value	EV/2006E EBITDA
Enbridge Inc.	ENB	SP	$34.60	2.9%	$1.63	$1.73	21.3	20.1	$3.30	$3.37	10.5	10.3	2.9	10.6
TransCanada Corp.	TRP	SO	$32.15	3.8%	$1.65	$1.80	19.5	17.9	$3.85	$3.97	8.4	8.1	2.3	8.6
TransAlta Corp.	TA	SP	$21.93	4.6%	$0.75	$1.00	29.2	21.9	$3.25	$3.48	6.7	6.3	1.7	8.4
Fortis	FTS	SO	$82.10	2.8%	$4.55	$4.80	18.0	17.1	$12.33	$11.84	6.7	6.9	1.8	8.5
Emera	EMA	SU	$18.21	4.9%	$0.80	$0.90	22.8	20.2	$2.45	$2.60	7.4	7.0	1.5	9.0
Canadian Utilities	CU.NV	SP	$72.65	3.0%	$4.20	$4.45	17.3	16.3	$9.19	$9.49	7.9	7.7	2.1	7.9
Average				**3.7%**			**21.4**	**18.9**			**7.9**	**7.7**	**2.1**	**8.8**

Company Name	Ticker	Rating	Price 08/17/05	Yield	EPU 2005E	EPU 2006E	P/E (x) 2005E	P/E (x) 2006E	Distributable Cash Flow / Unit 2005E	Distributable Cash Flow / Unit 2006E	P/CF (x) 2005E	P/CF (x) 2006E	Book Value	EV/2006E EBITDA
Enbridge Income Fund	ENF.UN	SP	$13.43	6.8%	$0.43	$0.39	31.2	34.4	$0.98	$0.96	13.7	14.0	1.7	10.1
Fort Chicago Energy Partners	FCE.UN	SO	$13.10	7.3%	$0.66	$0.60	19.8	21.7	$1.10	$1.09	11.9	12.0	2.0	10.9
Inter Pipeline Fund (LP)	IPL.UN	SP	$9.75	7.7%	$0.40	$0.40	24.4	24.5	$0.86	$0.89	11.4	11.0	1.7	11.3
Pembina Pipeline Income Fund	PIF.UN	SP	$14.95	7.0%	$0.60	$0.64	25.1	23.5	$1.08	$1.12	13.9	13.3	2.4	12.0
Average				**7.2%**			**25.1**	**26.0**			**12.7**	**12.6**	**1.9**	**11.1**

Note: Earnings per unit forecasts for FCE.UN, IPL.UN and PIF.UN are IBES estimates.

Source: Company reports, IBES and CIBC World Markets Inc.

The Terasen takeout valuation also far exceeds valuations on other recent pipeline and utility transactions. Most of the companies have been acquired at EBITDA multiples of 8x–9x and earnings multiples of 15x–18x.

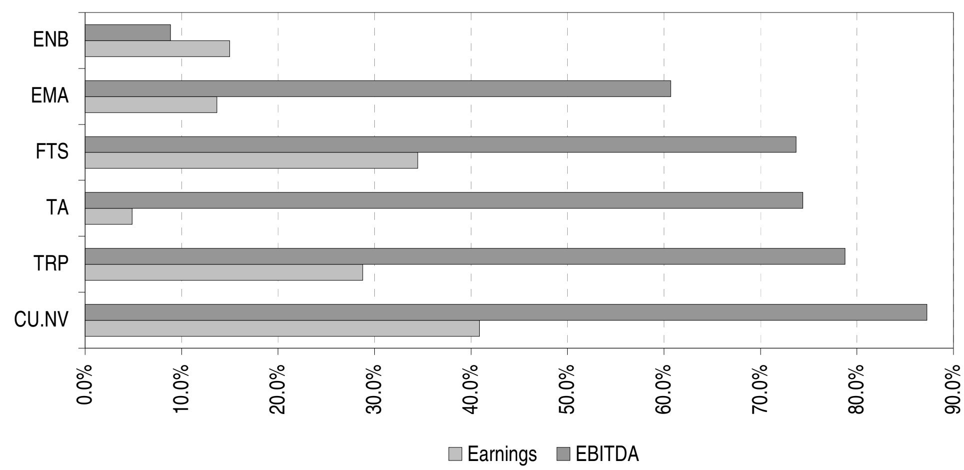
Exhibit 3. Valuation Parameters On Canadian And U.S. Utility Acquisitions

Date Announced	Buyer	Acquired Company	Purchase Price	Transaction Multiples: Earnings (x)	Book Value (x)	EBITDA (x)
21-Sep-01	Duke Energy	Westcoast Energy	US$8 billion	15.6	1.9	8.2
15-Aug-03	Fortis	Aquila's Western Canadian utilities	C$1.36 billion	18.3	1.8	8.3
20-Dec-04	Exelon Corp.	Public Service Enterprise Group	US$13.3 billion	16.2	2.3	NA
9-May-05	Duke Energy	Cinergy	US$9.0 billion	15.0	2.0	7.5
24-May-05	MidAmerican Energy	PacifiCorp	US$9.4 billion	19.4	1.5	8.6
1-Aug-05	**Kinder Morgan**	**Terasen**	**C$6.9 billion**	**23.2**	**2.7**	**11.8**

Source: Company reports and CIBC World Markets Inc.

We have analyzed potential share price appreciation in several of the Canadian stocks based on the 23x P/E and 11.8x EBITDA multiple Kinder Morgan is paying for Terasen. Valuation expansion to the Terasen takeout multiples would drive significant share price appreciation for the Canadian pipelines and utilities. Moving up to the 23x P/E multiple would require anywhere from a 10% to 40% increase in share prices. Moving up to the 11.8x EBITDA multiple would require anywhere from about 10% to 85% increase in share prices.

Exhibit 4. Potential Upside To Share Prices



Note: We applied Terasen's takeout earnings and EBITDA multiples to our 2006 estimates, with upside derived from closing prices on August 17.

Source: Company reports and CIBC World Markets Inc.

Several general and specific observations flow from our calculations:

- Most of the stocks show more upside to the acquisition EBITDA multiple than the acquisition P/E multiple. The ability to pay 11.8x EBITDA for a utility stock was unique and probably relates to the stability of cash flows from Terasen's 100% regulated pipeline and utility business. But achieving 10x–11x multiples is not at all out of the question.

- Enbridge shows the least upside to the Terasen acquisition multiple because it trades at a premium to the group. The market has appropriately already recognized much of the strategic value in the Enbridge asset base.

- TransAlta has little upside to the 23x earnings multiple because its earnings are currently depressed while it operates under legacy contracts to sell power below market prices. We see upside to earnings in the 2007–2009 timeframe that would tend to reduce the stock's P/E multiple.

In summary, TransCanada, Fortis and TransAlta show the biggest gaps between current valuation metrics and the Terasen takeout multiple. Emera (EMA–TSX, Sector Underperformer) and Canadian Utilities (CU.NV–TSX, Sector Performer) would have some upside but we see ownership restrictions in both that would likely prevent a takeover. Canadian Utilities is family controlled. Emera still has provisions that prevent concentration in voting shares of more than 15% and concentration of foreign holding of more than 25%.

Kinder Structure Accomplishes Much Of What An Income Trust Does

We believe that using a beneficial financing structure was key to supporting the abnormally high valuation Kinder Morgan is paying for Terasen. The structure involves issuing new debt and deducting interest expense for income tax purposes in both Canada and the U.S. In this sense, the structure is similar to an income trust that eliminates taxable income by creating inter-company loans and tax-deductible interest.

In the Kinder Morgan example, we estimate Canadian income tax liability could be significantly reduced with the double-dip interest structure. Kinder Morgan has stated it intends to issue about US$2.0 billion in new debt. Kinder's 10-year paper is trading at a premium to U.S. Treasuries of around 105 basis points. Assuming Kinder Morgan's credit rating is unchanged, and based on current 10-Year Treasury yields of 4.4%, Kinder could probably issue the new debt at around 5.45%. The pre-tax interest expense would then amount to about US$109 million.

The table below shows Terasen's taxable income and income tax paid in 2004 and then our estimates for 2005 and 2006. The 2006 numbers include the new interest expense from the Kinder Morgan acquisition. In 2004, Terasen paid about $78 million in cash income tax. We estimate that by 2006, despite achieving significant growth off of the 2004 base, the Terasen companies will only pay about $30 million in income tax.

Exhibit 5. Terasen's Income Tax Expense

	2004	2005E	2006E
Gas Distribution EBIT	$272.4	$279.9	$267.0
Petroleum Transportation EBIT	$99.3	$102.1	$104.3
Water Services EBIT	$11.4	$21.3	$24.6
Other EBIT	($11.7)	($15.2)	($12.5)
Express Pipeline Contribution	$15.0	$19.0	$22.0
Total EBIT	$386.4	$407.0	$405.4
Financing Expense (TER)	($166.6)	($180.0)	($190.0)
Financing Expense (KMI)	$0.0	$0.0	($130.8)
Pre-tax Income	$219.8	$227.0	$84.6
Tax Rate	35.5%	35.0%	35.0%
Income Tax	**$78.1**	**$79.5**	**$29.6**

1. Petroleum Transportation reflects expiry of Trans Mountain tolling agreement at the end of 2005.

2. Gas Distribution reflects lower allowed ROE resulting from drop in bond yields.

3. Express EBIT reflects expansion in service April 2005.

4. Taxes reflect cash taxes paid in 2004 and forecast cash taxes in 2005/6.

Source: Company reports and CIBC World Markets Inc.

Using the double-dip financing structure, we estimate Kinder will reduce the income taxes paid by about $50 million. This reduction equates to about 63% of Terasen's otherwise taxable income. And our models conservatively assume none of the Terasen assets are transferred to Kinder Morgan's MLP. The tax reduction would be even larger if that occurs. Income trust structures can eliminate up to 100% of taxable income, but we see the Kinder deal as a reasonable proxy for an income trust structure.

Canadian Regulators May Have To Liberalize Bias Against Utility Trust Conversions

Canadian regulators have recently expressed concerns about utility companies collecting taxes in rates but not paying them. Recent precedents suggest regulators may force a rate reduction if a utility converts to a trust structure. In the context of the Terasen deal, we think Canadian regulators may consider lifting some current restrictions and penalties involved in converting Canadian pipeline and utility assets into trust structures:

- If Canadian pipelines and utilities do not convert to income trusts, U.S. companies may eventually acquire them using a double-dip financing structure. This outcome raises several issues for Canadian governments and their regulatory agencies:
    - Canada could lose most of the corporate income tax revenue it collects from Canadian pipelines and utilities.
    - If Canadian companies are acquired, most of the future income from the assets will be taxed in the U.S. because the vast majority of shareholders will be American.
    - In the case of the U.S. company takeover, Canada also stands to lose head office jobs and some control over key energy infrastructure assets.
- Canadian companies can realize takeover valuations by instead converting all or a portion of their assets into Canadian income trusts.
    - If Canadian pipelines and utilities convert to income trusts in Canada, most of the income may eventually be taxed in Canada under personal income taxes.
    - In a trust conversion, Canadian utility customers are unharmed because utility bills remain unchanged and tax revenues remain in Canada.
- Therefore, Canadian regulators blocking income trust conversions in Canada may create the unintended consequences of delivering tax benefits to the U.S. at the expense of Canada and increasing foreign ownership of Canadian infrastructure assets.

We are not arguing against U.S. takeovers of Canadian companies, but we are suggesting it is illogical maintaining regulatory policies biased in their favour. Canadian regulators may have to reevaluate their stance to date against the creation of income trusts in the pipeline and utility sector. This stance has been founded on two issues: first, that taxes should not be collected in rates if they might not be paid; and second, that the debt within income trust structures may financially destabilize utilities and jeopardize their operations.

The National Energy Board has not tested the income trust conversion issue since it has not received an application for conversion of major pipeline assets. The Alliance Pipeline was converted to a trust but was governed by negotiated tolls, not cost of service rates with annual review.

However, provincial regulators have so far deterred the creation of income trusts. The Alberta Energy and Utilities Board (EUB) has placed the biggest obstacle in front of potential income trusts. In the AltaLink case, the EUB reduced the electric transmission company's rates because one of the owners, Ontario Teachers Pension Plan (OTPPB), was deemed a non-taxable entity. In its Review and Variance response from February 2005 the EUB stated:

> "…..the Board was not convinced that there was a reasonable expectation that OTPPB would incur and pay income taxes. In the Board's view, such a result would not be in keeping with the Board's belief that in a cost of service jurisdiction where revenue and costs are forecast on a prospective basis, a cost should only be recoverable in customer rates if there is a reasonable expectation that it will be incurred."

The EUB's position on AltaLink has negative implications for conversion of Alberta's utility assets into income trusts. In Alberta, if an income trust, like a pension fund, is viewed as having little probability of paying taxes, it may be forced to reduce regulated rates upon conversion.

AltaGas (ALA.UN–TSX, Not Rated) must have faced similar resistance to holding regulated Alberta utilities in a trust structure. Having converted from a corporation to a trust structure in 2004, AltaGas on May 25, 2005, announced the spin out of its regulated gas distribution business. On a recent conference call, AltaGas management stated the spin out would be "neutral to the company on an operating cash flow basis". What likely motivated AltaGas on the spin out, then, was not an improvement in the company's cash flow, but the threat the EUB would disallow the collection of taxes in gas distribution rates.

The British Columbia Utilities Commission (BCUC), like the EUB, has expressed tax and other concerns regarding income trust conversions. On July 29, 2004, the BCUC rejected the Pacific Northern Gas (PNG–TSX, Not Rated) request for trust conversion. Tax issues were central to the BCUC's concerns but so were capitalization issues. In an income trust structure, leverage tends to exceed regulated debt capitalization levels and actual equity ratios are thinner than regulated equity. These divergences were central to the BCUC decision:

> …the Commission panel concludes that deeming a capital structure at such wide variance with the underlying reality of the actual capital structure would be a material departure from the Commission's past regulatory practice…deeming a component of the cost of service equivalent to income taxes otherwise previously payable by a taxable corporation that had put in place a financial structure to minimize those taxes would establish a regulatory precedent with unknown implications…"

Though Canadian regulators have so far expressed a bias against trust conversions, they have not definitively rejected the concept. In British Columbia, the regulator seemed to indicate that it may approve the Pacific Northern Gas conversion if the company could show how such action would be in the public interest. In Alberta, the regulator seemed to indicate that it may allow for tax collection in rates as long as there was some potential for the utility owner to pay tax.

In the U.S., the Federal Energy Regulatory Commission (FERC) has taken a similar but perhaps more liberal and realistic approach to the tax issue. Until May of this year, the FERC maintained the so-called "Lakehead Policy" that held a limited partnership would be permitted to include an income tax allowance in its rates equal only to the proportion of its limited partnership interests owned by corporate partners. In a recent policy statement (dated May 4, 2005) FERC expanded the tax inclusion policy:

> "Under the [new] policy, all entities or individuals owning public utility assets would be permitted an income tax allowance on the income from those assets, provided that they have an actual <u>or potential</u> (emphasis added) income tax liability on that public utility income. Thus, a tax-paying

> corporation, partnership, limited liability corporation, or other pass-through entity would be permitted an income tax allowance on the income imputed to the corporation, or to the partners or the members of pass-through entities, provided that the corporation or the partners or the members have an actual or potential income tax liability on that income."

We believe the new FERC policy, applied to MLPs in the U.S., suggests the MLPs can collect taxes in rates even if the MLP itself does not pay income taxes. It would be collecting taxes on behalf of its members or partners that have a potential tax liability. Allowing utilities converting to income trusts to continue collecting taxes in rates on behalf of the individual income trust unit holders would be the analogous policy for a Canadian regulator.

Whether the Kinder Morgan acquisition of Terasen sparks a wave of Canadian pipeline and utility trust conversions remains to be seen. Two new regulatory precedents will likely be established in the coming months:

- Pacific Northern Gas is still applying to the BCUC for income trust conversion and may find success in its second attempt.
- Duke (DUK–NYSE, Sector Performer) has discussed the potential for creating a Canadian income trust that is bound to include gas-processing assets and may also include pipeline assets regulated by the NEB.

In light of the Kinder Morgan deal, there is an argument that regulators should be more lenient in these applications than they have with other income trust applications. A more positive outcome in the Pacific Northern Gas and Duke cases may bode well for the creation of more Canadian utility income trusts in the future.

Conclusion: More Value Creating Deals Likely On The Horizon

Canadian pipeline and utility companies must be considering strategic options to achieve the valuation Terasen did. Turning assets into income trusts is one way to surface value in the pipelines and utilities sector. Regulators should be more responsive to that alternative or U.S. companies may wind up owning more Canadian infrastructure with even fewer domestic tax benefits.

The future growth plans of the corporations should not deter them from turning assets into income trusts. The pipeline and utility companies could still maintain corporate parents as vehicles for growth. In fact, Kinder Morgan has already established this business model. It uses the MLP as its primary acquisition vehicle and pays cash bonuses for growth targets to the corporate parent.

TransCanada has perhaps the most to gain from turning assets into income trusts, yet has come less distance than Enbridge in using the trust vehicle. Enbridge already has an MLP and a Canadian income trust and trades at a relatively high EBITDA multiple. TransCanada hardly uses the structure and trades at a relatively low EBITDA multiple.

TransAlta may have upside to a trust structure in the medium term but not short term. The timing may not be right for conversion to a trust because the company is paying little in the way of cash taxes (about $5 million in 2004) and is making significant capital expenditures to improve the Alberta coal plants. Yet later this decade, cash taxes are bound to increase with profitability and spending will subside. At that time, upside from an income trust structure could materialize. In a report dated August 9, 2004, we calculated the shares were worth around $26.00 on a non-taxable basis.

The potential conversion of assets to income trusts is the focus of this report but is only one of the many strategic issues arising from the Kinder Morgan acquisition of Terasen. We believe Kinder Morgan has the size, expertise and relationships to undertake a much larger share of energy infrastructure growth opportunities than Terasen did on its own. Enbridge and TransCanada may have to seek more of their growth opportunities outside of Canada now. Apart from creating more trusts, potential strategic responses to the Kinder deal include acquiring more U.S. assets or acquiring U.S. corporations.

We see the acquisition of U.S. corporations more as potential upside than downside for Canadian companies. Lately, mergers have caused share price appreciation in both the buyer and target. Kinder Morgan was no exception. A similarly favourable response would likely greet Enbridge or TransCanada were they to acquire a solid U.S. company.

Terasen achieved valuations for its shareholders significantly beyond the current market valuation on most other Canadian pipeline and utility stocks. Now the other Canadian pipeline and utility corporations are obligated to seek similar valuations if they are available. TransCanada faces the biggest valuation gap, trading at a 6–7 point P/E discount and a 3-point EBITDA discount to the Terasen takeout valuation. Maximizing shareholder value may call for income trust conversions and/or mergers. Either way, given upside to the Terasen takeout multiple, it would be almost irresponsible not to seriously explore these options now.

Price Target Calculations

Our price targets for the pipeline and utility companies are derived from P/E multiples and dividend yields (relative to bond yields) primarily based on our 2006 earnings and dividend forecasts. We also consider our outlooks for the stocks beyond 2006. Our target dividend yields range from 2.8%–6.2% (based on a forecast 10-year Canada bond yield of about 4%).

Our target P/E multiples range from 16.4x–23x. This range is at the high end of the historical norm due to historically low bond yields. In the past 15 years, the stocks have tended to peak at no more than 17x–18x earnings, but have traded through those levels recently. The differences in target multiples between stocks under our coverage reflect different organic growth rates, potential acquisition activity, and current regulatory environment.

Key Risks To Price Targets

The main risk to our price targets is unanticipated changes in long bond yields. The correlation between bond yields and utility valuations has been high in recent years. If bond yields rise significantly, valuations across the group are likely to compress. Our price targets are based on 10-year Canada Bond yield of about 4.0%.

For individual companies, risks to price targets relate primarily to negative regulatory decisions that reduce returns on regulated assets, low acquisition activity, and unanticipated weakness in power prices.

Exhibit 6. Comparative Valuation Of Selected Canadian And U.S. Pipeline, Utility, And Power Generation Companies

Company	Ticker	Rating / Analyst	Price	52-Week Range High	52-Week Range Low	EPS 2003	EPS 2004	EPS 2005E	EPS 2006E	P/E Ratios 2003	P/E Ratios 2004	P/E Ratios 2005E	P/E Ratios 2006E	05E P/E Rel. To Group	Dividend Rate	Dividend Yield	Payout 2005E	Price Target	Total Return
Canadian Pipelines																			
Enbridge Inc.	ENB	SP / MA	$34.60	$36.60	$25.09	$1.41	$1.51	$1.63	$1.73	24.6	22.9	21.3	20.1	1.0	$1.00	2.9%	61.5%	$38.00	12.7%
Terasen Inc.	TER	SP / MA	$35.37	$36.95	$23.48	$1.33	$1.40	$1.50	$1.55	26.6	25.3	23.6	22.8	1.1	$0.90	2.5%	60.0%	$35.00	1.5%
TransCanada Corp.	TRP	SO / MA	$32.15	$34.16	$26.64	$1.59	$1.53	$1.65	$1.80	20.2	21.0	19.5	17.9	0.9	$1.22	3.8%	73.9%	$37.00	18.9%
Canadian Pipelines Average										**23.8**	**23.1**	**21.5**	**20.2**			**3.1%**	**65.2%**		
U.S. Pipelines																			
Duke Energy	DUK	SP / MA	$27.92	$30.55	$21.75	$1.28	$1.28	$1.65	$1.80	21.8	21.8	16.9	15.5	0.9	$1.24	4.4%	75.2%	$32.00	19.1%
El Paso	EP	NR	$11.45	$13.10	$7.51	($0.87)	($1.37)	$0.70	$0.86	NM	NM	16.4	13.3	0.9	$0.16	1.4%	22.9%	-	-
Kinder Morgan Inc.	KMI	NR	$91.57	$98.45	$59.14	$3.33	$3.81	$4.29	$4.88	27.5	24.0	21.3	18.8	1.2	$3.00	3.3%	69.9%	-	-
National Fuel Gas	NFG	NR	$28.09	$30.40	$25.91	$1.89	$1.98	$1.90	$2.04	14.9	14.2	14.8	13.8	0.8	$1.16	4.1%	61.1%	-	-
NiSource	NI	NR	$23.02	$25.50	$20.53	$1.64	$1.63	$1.50	$1.66	14.0	14.1	15.3	13.9	0.8	$0.92	4.0%	61.3%	-	-
Williams	WMB	NR	$20.73	$22.40	$11.36	($0.03)	$0.49	$0.86	$1.06	NM	42.3	24.1	19.6	1.3	$0.30	1.4%	34.9%	-	-
U.S. Pipelines Average										**19.6**	**23.3**	**18.1**	**15.8**			**3.4%**	**58.1%**		
Canadian Utilities																			
ATCO	ACO.NV.X	SU / MA	$77.25	$78.40	$48.75	$4.25	$4.62	$4.90	$5.25	18.2	16.7	15.8	14.7	0.8	$1.52	2.0%	31.0%	$64.00	(15.2%)
Canadian Utilities	CU.NV	SP / MA	$72.65	$74.45	$53.00	$3.95	$4.01	$4.20	$4.45	18.4	18.1	17.3	16.3	0.8	$2.20	3.0%	52.4%	$73.00	3.5%
Caribbean Utilities (US$)	CUP.U	NR	$11.40	$12.74	$9.75	$0.77	$0.13	$0.88	$0.96	14.8	NM	13.0	11.9	0.6	$0.66	5.8%	75.0%	-	-
Emera Inc.	EMA	SU / MA	$18.21	$19.97	$17.30	$1.26	$1.22	$0.80	$0.90	14.5	14.9	22.8	20.2	1.1	$0.89	4.9%	111.3%	$17.00	(1.8%)
Fortis	FTS	SO / MA	$82.10	$84.89	$59.10	$4.25	$4.29	$4.55	$4.80	19.3	19.1	18.0	17.1	0.9	$2.28	2.8%	50.1%	$90.00	12.4%
Gaz Metro L.P.	GZM.UN	SP / AP	$21.63	$23.67	$20.50	$1.39	$1.40	$1.31	$1.30	15.6	15.5	16.5	16.6	0.8	$1.36	6.3%	103.8%	$22.00	8.0%
TransAlta Corp.	TA	SP / MA	$21.93	$22.44	$15.65	$0.73	$0.66	$0.75	$1.00	30.0	33.2	29.2	21.9	1.4	$1.00	4.6%	133.3%	$23.00	9.4%
Canadian Utilities Average										**18.7**	**19.6**	**18.9**	**17.0**			**4.2%**	**79.6%**		
U.S. Utilities																			
Consolidated Edison	ED	NR	$45.93	$49.23	$40.75	$2.95	$2.67	$2.89	$2.99	15.6	17.2	15.9	15.4	1.1	$2.28	5.0%	78.9%	-	-
Dominion Resources	D	NR	$73.50	$79.18	$62.97	$4.50	$4.61	$5.05	$5.20	16.3	15.9	14.6	14.1	1.0	$2.68	3.6%	53.1%	-	-
DTE Energy	DTE	NR	$44.62	$48.22	$39.61	$2.97	$2.46	$3.48	$3.89	15.0	18.1	12.8	11.5	0.8	$2.06	4.6%	59.2%	-	-
Exelon	EXC	NR	$50.87	$54.88	$35.89	$2.61	$2.79	$3.09	$3.31	19.5	18.2	16.5	15.4	1.1	$1.60	3.1%	51.8%	-	-
FPL Group	FPL	NR	$40.73	$44.59	$33.55	$2.45	$2.63	$2.52	$2.72	16.7	15.5	16.2	15.0	1.1	$1.42	3.5%	54.4%	-	-
PPL Corp.	PPL	NR	$61.20	$65.12	$46.17	$3.71	$3.71	$4.13	$4.48	16.5	16.5	14.8	13.7	1.0	$2.00	3.3%	48.4%	-	-
U.S. Utilities Average										**16.6**	**16.9**	**15.1**	**14.2**			**3.9%**	**57.6%**		
Merchant Generation																			
AES Corporation	AES	NR	$15.25	$17.96	$9.47	$0.56	$0.58	$0.84	$0.99	27.2	26.3	18.2	15.4	0.8	$0.00	0.0%	0.0%	-	-
Calpine Corp.	CPN	NR	$3.33	$4.07	$1.33	$0.21	($0.97)	($0.95)	($0.54)	15.9	NM	NM	NM	-	$0.00	0.0%	0.0%	-	-
NRG Energy	NRG	NR	$37.55	$41.90	$25.59	($0.70)	$1.80	$1.37	$2.21	NM	20.9	27.4	17.0	1.2	$0.00	0.0%	0.0%	-	-
Reliant Energy	RRI	SO / MA	$12.38	$13.92	$9.08	$0.66	$0.07	$0.20	$0.45	18.8	NM	NM	27.5	-	$0.00	0.0%	0.0%	$16.00	29.2%
Merchant Generation Average										**20.6**	**23.6**	**22.8**	**20.0**			**0.0%**	**0.0%**		

Estimates are from CIBC World Markets with the exception of those companies that are not rated (sources: company reports, First Call and IBES).

Figures for Canadian companies in C$; figures for U.S. companies in US$.

EPS estimates for Caribbean Utilities are for the period ending April 30 the following year.

EPS estimates for GZM.UN, and NFG are for the period ending September 30.

SO = Sector Outperformer; SP = Sector Performer; SU = Sector Underperformer and NR = Not Rated.

Source: Company reports and CIBC World Markets Inc.

Exhibit 7. Comparative Valuation Of Selected Canadian And U.S. Pipeline, Utility, And Power Generation Companies

Company	Shares O/S (mlns.)	Mkt. Cap. ($ blns.)	Inst. Owners	52-Week % Change High	52-Week % Change Low	Cash Flow Per Share 2003	Cash Flow Per Share 2004	Cash Flow Per Share 2005E	Cash Flow Per Share 2006E	P/CF Ratios 2003	P/CF Ratios 2004	P/CF Ratios 2005E	P/CF Ratios 2006E	Book Value	Price/ Book	ROE 2005E	Debt To Cap	% Unreg. 05E EBIT	EV/05E EBITDA
Canadian Pipelines																			
Enbridge Inc.	348.3	$12.1	50%	(5%)	38%	$2.92	$3.08	$3.30	$3.37	11.9	11.3	10.5	10.3	$11.86	2.9	13.7%	62.1%	10.0%	10.5
Terasen Inc.	105.5	$3.7	15%	(4%)	51%	$2.82	$2.83	$3.01	$3.05	12.6	12.5	11.8	10.5	$13.53	2.6	11.2%	68.0%	5.0%	11.9
TransCanada Corp.	485.6	$15.6	45%	(6%)	21%	$3.96	$3.52	$3.85	$3.97	8.1	9.1	8.4	8.1	$13.86	2.3	12.0%	61.0%	16.0%	8.7
Canadian Pipelines Average										**10.9**	**11.0**	**10.2**	**9.6**		**2.6**	**12.3%**	**63.7%**	**10.3%**	**10.4**
U.S. Pipelines																			
Duke Energy	926.4	$25.9	67%	(9%)	28%	$4.35	$4.44	$2.98	$3.65	6.4	6.3	9.4	7.6	$17.58	1.6	9.5%	50.0%	25.0%	9.1
El Paso	645.7	$7.4	79%	(13%)	52%	$2.06	$2.43			5.6	4.7			$6.93	1.7	-	82.0%		7.5
Kinder Morgan Inc.	122.5	$11.2	82%	(7%)	55%	$4.89	$5.26			18.7	17.4			$22.55	4.1	17.0%	44.1%		13.1
National Fuel Gas	83.5	$2.3	46%	(8%)	8%	$4.95	$4.93			5.7	6.2			$15.86	1.8	13.6%	47.7%		6.5
NiSource	272.3	$6.3	73%	(10%)	12%	$2.34	$3.90			9.8	6.5			$17.97	1.3	9.5%	54.9%		7.6
Williams	571.5	$11.8	60%	(7%)	82%	$1.56	$2.36			13.3	9.5			$9.37	2.2	5.8%	59.1%		8.1
U.S. Pipelines Average										**9.9**	**8.4**				**2.1**	**12.4%**	**56.3%**		**8.7**
Canadian Utilities																			
ATCO Ltd.	30.0	$2.3	35%	(1%)	58%	$9.35	$9.95	$10.75	$11.26	8.3	7.8	7.2	6.9	$43.06	1.8	11.7%	51.0%	20.0%	7.2
Canadian Utilities	63.5	$4.6	15%	(2%)	37%	$8.30	$8.50	$9.19	$9.49	8.8	8.5	7.9	7.7	$34.26	2.1	12.6%	52.0%	36.5%	8.2
Caribbean Utilities (US$)	25.0	$0.3	2%	(11%)	17%	$1.32	$1.07			8.6	10.7			$5.02	2.3	2.6%	53.0%	0.0%	10.6
Emera Inc.	109.6	$2.0	18%	(9%)	5%	$2.22	$2.80	$2.45	$2.60	8.2	6.5	7.4	7.0	$12.49	1.5	6.5%	54.1%	5.0%	9.1
Fortis Inc.	25.7	$2.1	32%	(3%)	39%	$9.28	$12.81	$12.33	$11.84	8.8	6.4	6.7	6.9	$45.88	1.8	9.3%	58.6%	21.0%	8.9
Gaz Metro L.P.	117.5	$2.5	25%	(9%)	6%	$3.16	$3.06	$3.15	$3.35	6.8	7.1	6.9	6.5	$8.87	2.4	17.2%	53.3%	2.0%	10.0
TransAlta Corp.	196.4	$4.3	55%	(2%)	40%	$2.86	$3.02	$3.25	$3.48	7.7	7.3	6.7	6.3	$12.61	1.7	6.0%	51.9%	100.0%	8.9
Canadian Utilities Average										**8.2**	**7.7**	**7.1**	**6.9**		**1.9**	**9.4%**	**53.4%**	**26.4%**	**9.0**
U.S. Utilities																			
Consolidated Edison	243.4	$11.2	44%	(7%)	13%	$6.31	$6.54			7.3	7.5			$29.36	1.6	9.3%	51.6%		9.3
Dominion Resources	341.0	$25.1	61%	(7%)	17%	$7.25	$8.58			10.1	9.2			$31.61	2.3	14.1%	61.9%		8.5
DTE Energy	174.2	$7.8	61%	(7%)	13%	$5.63	$5.75			7.9	8.4			$31.26	1.4	7.8%	60.6%		8.1
Exelon	670.6	$34.1	68%	(7%)	42%	$5.20	$6.65			9.8	8.3			$14.97	3.4	20.6%	58.2%		9.0
FPL Group	392.0	$16.0	68%	(9%)	21%	$6.12	$7.39			6.7	6.0			$21.06	1.9	13.4%	54.4%		8.9
PPL Corp.	190.0	$11.6	59%	(6%)	33%	$7.87	$8.13			7.8	7.5			$22.67	2.7	18.2%	62.1%		8.4
U.S. Utilities Average										**8.3**	**7.8**				**2.2**	**13.9%**	**58.1%**		**8.7**
Merchant Generation																			
AES Corporation	653.2	$10.0	82%	(15%)	61%	$2.52	$2.43			6.1	6.3			$2.68	-	NM	84.3%	100.0%	7.7
Calpine Corp.	568.0	$1.9	62%	(18%)	150%	$0.73	$0.02			4.6	-			$7.15	0.5	0.9%	80.8%	100.0%	16.4
NRG Energy	87.0	$3.3	81%	(10%)	47%	-	$5.78			-	6.5			$25.21	1.5	NM	55.2%	100.0%	11.5
Reliant Energy	301.0	$3.7	72%	(11%)	36%	$2.76	$0.96	$1.64	$1.94	4.5	12.9	7.5	6.4	$14.40	0.9	0.5%	54.9%	100.0%	9.6
Merchant Generation Average										**5.0**	**8.6**				**0.9**	**0.7%**	**68.8%**	**100.0%**	**11.3**

Estimates are from CIBC World Markets with the exception of those companies that are not rated (sources: company reports, First Call and IBES).

Figures for Canadian companies in C$; figures for U.S. companies in US$.

For those companies not rated, ROE figures are actuals for the most recent fiscal year.

EPS estimates for Caribbean Utilities are for the period ending April 30 the following year.

EPS estimates for GZM.UN, and NFG are for the period ending September 30.

Source: Company reports and CIBC World Markets Inc.

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Stock Prices as of 08/19/2005:

Atco Ltd. (7, 13) (ACO.NV.X-TSX, C$76.55, Sector Underperformer)
Canadian Utilities Ltd. (7, 13) (CU.NV-TSX, C$69.30, Sector Performer)
Duke Energy (2a, 2d, 2g, 7) (DUK-NYSE, US$28.14, Sector Performer)
Emera Inc. (2g, 7) (EMA-TSX, C$18.37, Sector Underperformer)
Enbridge Inc. (2a, 2c, 2e, 2g, 7) (ENB-TSX, C$34.25, Sector Performer)
Enbridge Income Fund (2a, 2c, 2e, 7) (ENF.UN-TSX, C$13.20, Sector Performer)
Fort Chicago Energy Partners, L.P. (2g, 7) (FCE.UN-TSX, C$12.83, Sector Outperformer)
Fortis Inc. (2a, 2c, 2e, 7) (FTS-TSX, C$81.86, Sector Outperformer)
Gaz Métro Limited Partnership (2a, 2c, 2e) (GZM.UN-TSX, C$21.70, Sector Performer)
Inter Pipeline Fund, L.P. (2a, 2e, 2g, 7) (IPL.UN-TSX, C$9.75, Sector Performer)
Pembina Pipeline Income Fund (2a, 2e, 2g, 7) (PIF.UN-TSX, C$15.00, Sector Performer)
Reliant Energy Inc. (RRI-NYSE, US$12.35, Sector Outperformer)
Terasen Inc. (2a, 2c, 2e, 7) (TER-TSX, C$35.55, Sector Performer)
TransAlta Corporation (2a, 2e, 2g, 7, 9) (TA-TSX, C$21.56, Sector Performer)
TransCanada Corp. (7) (TRP-TSX, C$31.49, Sector Outperformer)

Companies Mentioned in this Report that Are Not Covered by CIBC World Markets:

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AES Corp (AES-NYSE, US$15.31, Not Rated)
AltaGas Income Trust (ALA.UN-TSX, C$26.65, Not Rated)
Aquila, Inc. (ILA-NYSE, US$3.82, Not Rated)
Berkshire Hathaway (BRK-NYSE, US$90050.00, Not Rated)
Calpine Corporation (CPN-NYSE, US$2.93, Not Rated)
Caribbean Utilities Company Ltd. (CUP.U-TSX, C$11.21, Not Rated)
Cinergy Corp (CIN-NYSE, US$42.20, Not Rated)
Consolidated Edison (ED-NYSE, US$46.08, Not Rated)
Dominion Resources (D-NYSE, US$74.50, Not Rated)
DTE Energy Company (DTE-NYSE, US$45.00, Not Rated)
El Paso Corp. (EP-NYSE, US$11.39, Not Rated)
Exelon (EXC-NYSE, US$50.89, Not Rated)
FPL Group Inc. (FPL-NYSE, US$40.90, Not Rated)
Kinder Morgan Energy Partners (KMP-NYSE, US$50.24, Not Rated)
Kinder Morgan, Inc. (KMI-NYSE, US$91.63, Not Rated)
National Fuel Gas (NFG-NYSE, US$28.20, Not Rated)
Nisource (NI-NYSE, US$23.17, Not Rated)
NRG Energy (NRG-NYSE, US$37.45, Not Rated)
Pacific Northern Gas Ltd. (PNG-TSX, C$19.40, Not Rated)
PPL Corporation (PPL-NYSE, US$61.35, Not Rated)
Public Service Enterprise Group (PEG-NYSE, US$60.69, Not Rated)

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Williams Cos Inc. (WMB-NYSE, US$20.73, Not Rated)

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2f CIBC World Markets Corp. expects to receive or intends to seek compensation for investment banking services from this company in the next 3 months.

2g CIBC World Markets Inc. expects to receive or intends to seek compensation for investment banking services from this company in the next 3 months.

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Key to Important Disclosure Footnotes: (Continued)

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11 The equity securities of this company are restricted voting shares.

12 The equity securities of this company are subordinate voting shares.

13 The equity securities of this company are non-voting shares.

14 The equity securities of this company are limited voting shares.

CIBC World Markets Price Chart

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Abbreviation	Rating	Description
Stock Ratings		
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SP	Sector Performer	Stock is expected to perform in line with the sector during the next 12-18 months.
SU	Sector Underperformer	Stock is expected to underperform the sector during the next 12-18 months.
NR	Not Rated	CIBC does not maintain an investment recommendation on the stock.
R	Restricted	CIBC World Markets is restricted*** from rating the stock.
Stock Ratings Prior To August 26, 2002		
SB	Strong Buy	Expected total return over 12 months of at least 25%.
B	Buy	Expected total return over 12 months of at least 15%.
H	Hold	Expected total return over 12 months of at least 0%-15%.
UP	Underperform	Expected negative total return over 12 months.
S	Suspended	Stock coverage is temporarily halted.
DR	Dropped	Stock coverage is discontinued.
UR	Under Review	Under Review
Sector Weightings**		
O	Overweight	Sector is expected to outperform the broader market averages.
M	Market Weight	Sector is expected to equal the performance of the broader market averages.
U	Underweight	Sector is expected to underperform the broader market averages.
NA	None	Sector rating is not applicable.

**Broader market averages refer to the S&P 500 in the U.S. and the S&P/TSX Composite in Canada.
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Sector Performer (Hold/Neutral)	415	49.5%	Sector Performer (Hold/Neutral)	246	59.3%
Sector Underperformer (Sell)	134	16.0%	Sector Underperformer (Sell)	71	53.0%
Restricted	7	0.8%	Restricted	7	100.0%

Ratings Distribution: Pipelines, Utilities, & Power Coverage Universe

(as of 19 Aug 2005)	Count	Percent	Inv. Banking Relationships	Count	Percent
Sector Outperformer (Buy)	3	27.3%	Sector Outperformer (Buy)	1	33.3%
Sector Performer (Hold/Neutral)	6	54.5%	Sector Performer (Hold/Neutral)	4	66.7%
Sector Underperformer (Sell)	2	18.2%	Sector Underperformer (Sell)	1	50.0%
Restricted	0	0.0%	Restricted	0	0.0%

Pipelines, Utilities, & Power Sector includes the following tickers: ACO.NV.X, CU.NV, DUK, EEP, EMA, ENB, FTS, RRI, TA, TER, TRP.

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DOWNGRADE RATING

CREDIT SUISSE | FIRST BOSTON

Equity Research Canada

Terasen Inc.

TER.TO

Downgrade Based on Valuation

- **We are downgrading Terasen from Outperform to Neutral, based solely on valuation. We continue to like the fundamental story from a growth and risk perspective but find the stock expensive. For current investors in the stock, we recommend continuing to hold the shares.**

- **Terasen is up 28% in the past 12 months, handsomely outperforming peers. It currently trades at a premium multiple of 9.5x 05E EV/EBITDA, 10.9x 05E price to cash flow and 18.9x 05E price to earnings. We estimate earnings to grow 11% for 2005.**

- **We believe Terasen deserves to trade at a premium versus its peers. We judge the risks at Terasen to be the lowest in our coverage universe, with good prospects for growth from expansions and new pipelines in the oil sands area of Alberta.**

- **We believe Terasen's proposed TMX expansion is best positioned versus competitor Enbridge, owing to its staged development. A staged project can match new oil sands projects more closely versus the alternative mega-project proposal by Enbridge (400 kbpd in 2009). Terasen's proposal is a pipeline-twinning project, avoiding potential land claim issues we believe Enbridge could face in northern British Columbia. The $2.5 billion proposed pipeline would commence operations as early as 2007, with completion by 2009.**

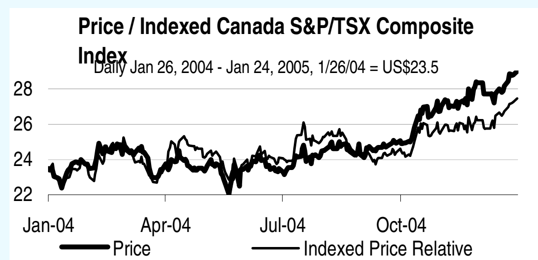
- **If Terasen is successful, we estimate the TMX expansion could add approximately $2-4 to NAV. With our 12-month target of $26.50, we feel the shares are priced to perfection at this time.**

- **Our preferred name at present is TransCanada, based on valuation, news flow on Alaska pipeline, news flow on Mackenzie pipeline and Bruce Power in Ontario.**

Terasen is a diversified utility with oil pipelines, local gas distribution assets and water utilities.

Rating	**NEUTRAL***
Price (25 Jan 05)	**29.50 (C$)**
Target price (12 months)	**26.50 (C$)**
52 week high - low	**28.99 - 22.05**
Market cap. (C$m)	**3,091.90**
Enterprise value (C$m)	**6,144.60**
Region / Country	**Americas / Canada**
Sector	**Pipelines**
Analyst's Coverage Universe	**Pipelines and Utilities**
Weighting (vs. broad market)	**MARKET WEIGHT**
Date	**26 January 2005**

**** Stock ratings are relative to the coverage universe in each analyst's or each team's respective sector.***



On 01/24/05 the Canada S&P/TSX Composite Index index closed at 9,078.20

Year	12/03A	12/04E	12/05E
EPS (CSFB adj., C$)	1.31	1.40	1.56
Prev. EPS (C$)			
P/E (x)	22.5	21.1	18.9
P/E rel. (%)	102.9	126.8	129.6
Q1 EPS	0.71	0.76	0.84
Q2	0.08	0.09	0.10
Q3	-0.07	-0.03	-0.04
Q4	1.15	0.59	0.65

Number of shares (m)	104.81	IC (Current, C$m)	—
BV/Share (Current, C$)	14.13	EV/IC (x)	—
Net Debt (Current, C$m)	3,052.7	Dividend (Current, C$m)	0.84
Net debt/Total cap. (Current)	67.5%	Dividend yield	2.8%

Year	12/03A	12/04E	12/05E
Revenues (C$m)	986.9	1,030.7	1,059.9
EBITDA (C$m)	569.7	618.7	647.9
OCFPS (C$)	5.63	2.88	2.71
P/OCF (x)	5.2	10.2	10.9
EV/EBITDA (x)	10.8	9.9	9.5
ROIC	—	10.8%	—

Source: Company data, CREDIT SUISSE FIRST BOSTON (CSFB) estimates

research team

Dominique Barker, CA, CFA
416 352 4594
dominique.barker@csfb.com

Peter Best
416 352 4585
peter.best@csfb.com

Richelle Embree
416 352 4584
richelle.embree@csfb.com

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Alternative Analysis of Valuations and Yields

We see from the following table that Terasen (TER.TO, C$29.50, NEUTRAL, TP C$26.50, MW) is trading at a premium valuation versus its historical average (the lower the %, the higher the valuation). As we discussed in our initiation (January 2004), we believe a premium valuation is deserved owing to growth prospects, lower risk, and relationship with financial players (OMERS and Ontario Teachers).

Exhibit 1: Historical Range of Dividend Yield, as a Percent of 10Y GOC

	TRP	ENB	TER	FTS	TA	EMA
TODAY – January 25	91%	73%	69%	75%	125%	107%
10-year average	**92%**	**70%**	**72%**	**83%**	**96%**	**94%**
5-year average	93%	68%	73%	83%	104%	100%
3-year average	89%	71%	73%	77%	114%	104%
1-year average	92%	76%	73%	77%	128%	106%
Ex-1999-2002 avg	**88%**	**74%**	**72%**	**80%**	**99%**	**93%**

Source: Factset

TransCanada (TRP.TO, C$30, OUTPERFORM, TP C$29.00, MW) is trading near its historical average, which we believe unfairly penalizes the company in its "post-dividend-cut" years. Excluding the rocky period 1999-2002, TransCanada traded at an average dividend yield of 88% of the Canada 10-year bond yield. We think it should trade at these levels at a minimum, and possibly lower (higher valuation), owing to good future prospects for the company.

Our preferred name at this time is TransCanada, based on valuation, news flow on Alaska pipeline, news flow on Mackenzie pipeline and Bruce Power in Ontario.

Using our estimates of 2005 dividends (expected to be announced when Q4 earnings are released), a 10-year Government of Canada bond yield of 4.75%, and the 10-year average of the historical yield as a % of 10Y GOC (per above table), we calculate the following valuations:

Exhibit 2: Using the 10-year historical average % of today's GOC (4.17%)

	TRP	ENB	TER
04 dividend	1.16	1.83	0.84
% Of GOC 10 Year	**92%**	**70%**	**72%**
Implied value	28.05	57.73	25.86
05E dividend	**1.24**	**1.96**	**0.93**
Implied value	**29.99**	**61.83**	**28.63**

Source: Factset, CSFB estimates

However, we argue that Enbridge (ENB.TO, C$59.29, NEUTRAL, TP C$55.00, MW) should be valued at a higher (lower value) rate than historical, owing to its limited growth opportunities and higher risk. We also believe Terasen is coming into the spotlight, and deserves a higher valuation, as discussed previously. Finally, we think using a 10-year average for TransCanada skews the value downward, because of the dividend cut in 1999. Using 88% for TRP and 74% for ENB (the 10-year average excluding 1999 to 2002), and using 70% for Terasen yields the following valuations:

Exhibit 3: Adjusting the % Of 10 Year, TRP is preferred name

	TRP	ENB	TER
Relative spread	**88%**	**74%**	**70%**
05E dividend	**1.24**	**1.96**	**0.93**
Implied value	**29.67**	**55.76**	**27.97**

Source: Company data, CSFB estimates

Exhibit 4: Pipeline Comps

Company	Ticker	Rating	Target Price	Target Upside	Price 1/24/2005	MC	EV	EV/EBITDA 2004E	EV/EBITDA 2005E	P/CF 2004E	P/CF 2005E	P/E 2004E	P/E 2005E
Canada					*C$*	*C$ bil*	*C$ bil*						
TransCanada Corp.	TRP.TO	O	29.00	-4%	30.10	14.6	25.4	8.8x	8.6x	9.3x	9.1x	19.2x	17.3x
Enbridge Inc.	ENB.TO	N	55.00	-7%	59.25	10.2	15.2	10.4x	9.1x	9.9x	9.4x	19.5x	18.3x
Terasen Inc	TER.TO	N	26.50	-9%	28.99	3.0	6.3	10.1x	9.6x	10.1x	10.7x	20.8x	18.6x
Canadian Pipeline average								**9.8x**	**9.1x**	**9.7x**	**9.7x**	**19.8x**	**18.1x**
US					*US$*	*US$ bil*	*US$ bil*						
CenterPoint Energy, Inc.	CNP	O	12.00	8%	11.10	3.4	14.1	8.0x	10.8x	4.1x	5.4x	32.6x	18.5x
Dynegy Inc.	DYN	R	R	R	R	R	R	R	R	R	R	R	R
El Paso Corp.	EP	R	R	R	R	R	R	R	R	R	R	R	R
Equitable Resources	EQT	N	54.00	-5%	56.79	3.5	4.3	10.1x	9.3x	11.4x	10.0x	18.9x	16.5x
Keyspan Corp	KSE	N	37.00	-5%	38.96	6.3	11.5	7.0x	na	na	na	15.0x	16.7x
Kinder Morgan, Inc.	KMI	O	76.00	2%	74.86	9.3	12.5	11.7x	na	na	na	19.6x	17.6x
National Fuel Gas Co.	NFG	U	25.00	-9%	27.57	2.3	3.7	7.7x	na	na	na	13.9x	15.3x
NiSource Inc	NI	N	21.00	-8%	22.71	6.0	12.8	8.1x	na	na	na	14.2x	14.7x
ONEOK, Inc.	OKE	N	25.00	-8%	27.32	2.8	5.0	8.3x	na	na	na	12.1x	11.9x
Questar	STR	N	42.00	-18%	51.08	4.3	5.1	7.0x	6.4x	8.1x	7.6x	20.0x	17.9x
Sempra Energy	SRE	N	36.00	-1%	36.22	8.5	12.7	6.7x	na	na	na	11.0x	12.8x
Western Gas Resources, Inc	WGR	N	27.50	-5%	29.06	2.1	2.4	7.0x	6.3x	8.7x	7.8x	18.2x	15.7x
Williams Companies	WMB	N	15.00	-5%	15.79	8.8	16.3	9.4x	7.9x	11.0x	7.7x	79.0x	18.8x
US Pipeline average								**8.3x**	**8.1x**	**8.6x**	**7.7x**	**23.2x**	**16.0x**

Source: Company data, CSFB estimates

Companies Mentioned *(Price as of 25 Jan 05)*

Terasen Inc (TER.TO, C$29.50, NEUTRAL, TP C$26.50, MARKET WEIGHT)
TransCanada Corp. (TRP.TO, C$30, OUTPERFORM, TP C$29.00, MARKET WEIGHT)
Enbridge Inc. (ENB.TO, C$59.29, NEUTRAL, TP C$55.00, MARKET WEIGHT)
TransAlta Corporation (TA.TO, C$19.19, UNDERPERFORM, TP C$12.00, MARKET WEIGHT)
Fortis Inc. (FTS.TO, C$73.24, OUTPERFORM, TP C$70.00, MARKET WEIGHT)
Emera (EMA.TO, C$19.87, NEUTRAL, TP C$19.00, MARKET WEIGHT)

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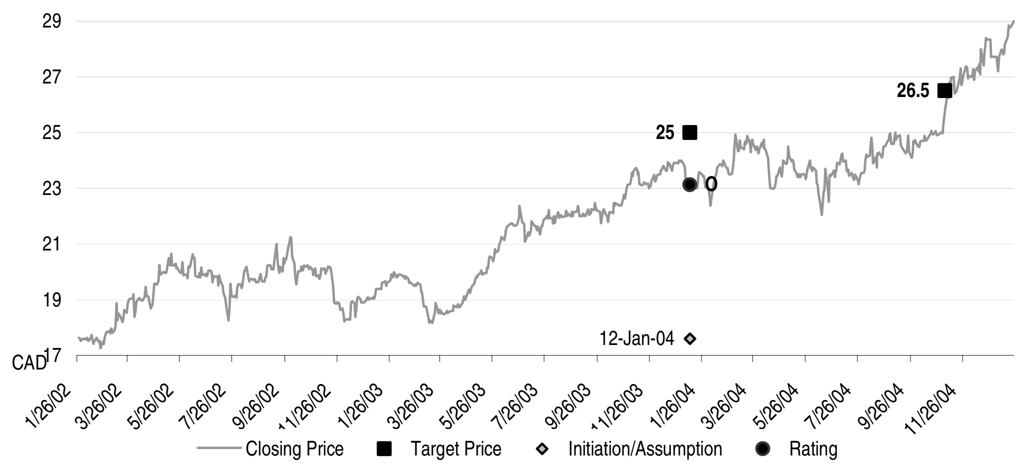
3-Year Price, Target Price and Rating Change History Chart for TER.TO



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Prior to 9-Sep-02: SB=Strong Buy; B=Buy; H=Hold; S=Sell; R=Restricted; NR=Not Rated

TER.TO Date	Closing Price (CAD)	Target Price (CAD)	Rating	Initiation/ Assumption
1/12/04	23.13	25	OUTPERFORM	X
11/5/04	25.8	26.5		

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Method: Dividend yield versus the 10 year government of Canada forecast bond yield.
Risks: Rapid rise in the 10-year government of Canada bond yield.

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EARNINGS

CREDIT SUISSE FIRST BOSTON

Equity Research Canada

Terasen Inc

TER.TO

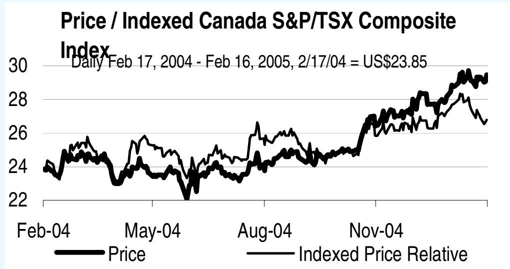
Q4/04 In Line

- **Terasen reported Q4/04 EPS of $0.58, which is in line with consensus and our estimate of $0.59.**
- **We are lowering our 2005 EPS from $1.56 to $1.49 due to anticipated weaker volumes and throughput at Trans Mountain in Q1/05, driven by production outages in the Alberta oil sands and refinery turnarounds on the west coast.**
- **Projected 2005 capital expenditures of $350 million were higher than our estimate of $165 million. The capex will be financed with a combination of long-term debt, short-term debt and internally generated funds.**
- **With higher 2005 capex, we believe that leverage is getting high. We estimate that 2005 debt/cap will increase to 67% from current levels of 66%. While this is within the company's target range, it continues to be high relative to its peers.**
- **We continue to like the fundamental story from a growth perspective but find the stock expensive at these levels. We maintain our Neutral rating and 12-month target price of $26.50, which implies 17.8xP/E, 9.4xP/CF and 3.4% yield.**

Terasen is a diversified utility with oil pipelines, local gas distribution assets and water utilities.

Rating	**NEUTRAL***
Price (17 Feb 05)	**29.34 (C$)**
Target price (12 months)	**26.50 (C$)**
52 week high - low	**29.71 - 22.05**
Market cap. (C$m)	**3,078.53**
Enterprise value (C$m)	**6,042.43**
Region / Country	**Americas / Canada**
Sector	**Pipelines**
Analyst's Coverage Universe	**Pipelines and Utilities**
Weighting (vs. broad market)	**MARKET WEIGHT**
Date	**17 February 2005**

**** Stock ratings are relative to the coverage universe in each analyst's or each team's respective sector.***



On 02/16/05 the Canada S&P/TSX Composite Index index closed at 9,619.26

Year	12/03A	12/04E	12/05E
EPS (CSFB adj., C$)	**1.31**	**1.39**	**1.49**
Prev. EPS (C$)			**1.56**
P/E (x)	**22.4**	**21.1**	**19.8**
P/E rel. (%)	—	—	—
Q1 EPS	**0.71**	**0.76**	**0.77**
Q2	**0.08**	**0.09**	**0.10**
Q3	**-0.07**	**-0.03**	**-0.04**
Q4	**1.15**	**0.58**	**0.65**

Number of shares (m)	**104.93**	IC (Current, C$m)	—
BV/Share (Current, C$)	**14.34**	EV/IC (x)	—
Net Debt (Current, C$m)	**2,963.9**	Dividend (Current, C$m)	**0.90**
Net debt/Total cap. (Current)	**66.3%**	Dividend yield	**3.1%**

Year	12/03A	12/04E	12/05E
Revenues (C$m)	**986.9**	**1,075.4**	**1,014.5**
EBITDA (C$m)	**569.7**	**803.4**	**635.1**
OCFPS (C$)	**5.63**	**2.83**	**2.82**
P/OCF (x)	**5.2**	**10.4**	**10.4**
EV/EBITDA (x)	**10.6**	**7.5**	**9.5**
ROIC	—	**10.8%**	—

Source: Company data, CREDIT SUISSE FIRST BOSTON (CSFB) estimates

research team

Dominique Barker, CA, CFA
416 352 4594
dominique.barker@csfb.com

Peter Best
416 352 4585
peter.best@csfb.com

Richelle Embree
416 352 4584
richelle.embree@csfb.com

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Companies Mentioned *(Price as of 17 Feb 05)*

Terasen Inc (TER.TO, C$29.34, NEUTRAL, TP C$26.50, MARKET WEIGHT)

Disclosure Appendix

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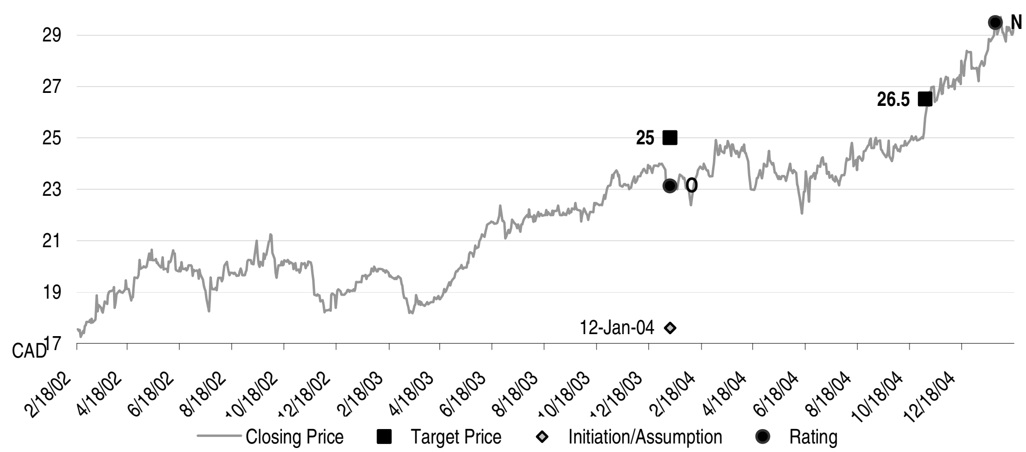
3-Year Price, Target Price and Rating Change History Chart for TER.TO



Current: O=Outperform; N=Neutral; U=Underperform; R=Restricted; NR=Not Rated
Prior to 9-Sep-02: SB=Strong Buy; B=Buy; H=Hold; S=Sell; R=Restricted; NR=Not Rated

TER.TO Date	Closing Price (CAD)	Target Price (CAD)	Rating	Initiation/ Assumption
1/12/04	23.13	25	OUTPERFORM	X
11/5/04	25.8	26.5		
1/26/05	29.48		NEUTRAL	

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Neutral: The stock’s total return is expected to be in line with the industry average* (range of ±10%) over the next 12 months.

Underperform:** The stock’s total return is expected to underperform the industry average* by 10-15% or more over the next 12 months.

**The industry average refers to the average total return of the analyst's industry coverage universe (except with respect to Asia/Pacific, Latin America and Emerging Markets, where stock ratings are relative to the relevant country index, and CSFB HOLT Small and Mid-Cap Advisor stocks, where stock ratings are relative to the regional CSFB HOLT Small and Mid-Cap Advisor investment universe.*

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Global Ratings Distribution

Outperform/Buy*	37%	(55% banking clients)
Neutral/Hold*	43%	(56% banking clients)
Underperform/Sell*	17%	(43% banking clients)
Restricted	2%	

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See the Companies Mentioned section for full company names.

Price Target: (12 months) for (TER.TO)

Method: Dividend yield versus the 10 year government of Canada forecast bond yield.

Risks: Rapid rise in the 10-year government of Canada bond yield.

See the Companies Mentioned section for full company names.

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COMPANY UPDATE

CREDIT SUISSE | FIRST BOSTON

Equity Research Canada

Terasen Inc

TER.TO

TER Update

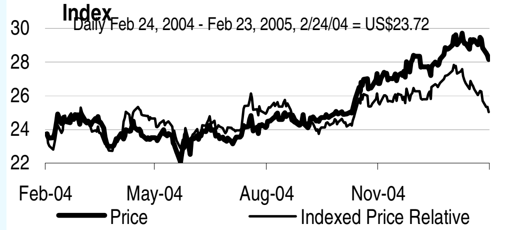
- **We are introducing our 2006E EPS of $1.59 for Terasen, and maintaining our 2005E EPS of $1.49.**
- **We reiterate our Neutral rating and $26.50 target price.**

Terasen is a diversified utility with oil pipelines, local gas distribution assets and water utilities.

Rating	NEUTRAL*
Price (23 Feb 05)	28.15 (C$)
Target price (12 months)	26.50 (C$)
52 week high - low	29.71 - 22.05
Market cap. (C$m)	2,953.67
Enterprise value (C$m)	6,163.37
Region / Country	Americas / Canada
Sector	Pipelines
Analyst's Coverage Universe	Pipelines and Utilities
Weighting (vs. broad market)	MARKET WEIGHT
Date	24 February 2005

**** Stock ratings are relative to the coverage universe in each analyst's or each team's respective sector.***

Price / Indexed Canada S&P/TSX Composite Index



On 02/23/05 the Canada S&P/TSX Composite Index index closed at 9,675.69

Year	12/04A	12/05E	12/06E
EPS (CSFB adj., C$)	1.39	1.49	1.59
Prev. EPS (C$)			
P/E (x)	20.2	18.9	17.7
P/E rel. (%)	NM	NM	NM
Q1 EPS	0.76	0.77	
Q2	0.09	0.10	
Q3	-0.03	-0.04	
Q4	0.58	0.65	

Number of shares (m)	104.93	IC (Current, C$m)	—
BV/Share (Current, C$)	14.34	EV/IC (x)	
Net Debt (Current, C$m)	2,963.9	Dividend (Current, C$m)	0.90
Net debt/Total cap. (Current)	66.3%	Dividend yield	3.2%

Year	12/04A	12/05E	12/06E
Revenues (C$m)	1,075.4	1,015.3	1,037.4
EBITDA (C$m)	803.4	635.9	625.4
OCFPS (C$)	2.83	2.82	2.63
P/OCF (x)	9.9	10.0	10.7
EV/EBITDA (x)	7.7	9.7	9.9
ROIC	10.8%	—	—

Source: Company data, CREDIT SUISSE FIRST BOSTON (CSFB) estimates

research team

Dominique Barker, CA, CFA
416 352 4594
dominique.barker@csfb.com

Peter Best
416 352 4585
peter.best@csfb.com

Richelle Embree
416 352 4584
richelle.embree@csfb.com

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Companies Mentioned *(Price as of 23 Feb 05)*

Terasen Inc (TER.TO, C$28.15, NEUTRAL, TP C$26.50, MARKET WEIGHT)

Disclosure Appendix

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I, Dominique Barker, certify that (1) the views expressed in this report accurately reflect my personal views about all of the subject companies and securities and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this report.

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3-Year Price, Target Price and Rating Change History Chart for TER.TO

Current: O=Outperform; N=Neutral; U=Underperform; R=Restricted; NR=Not Rated

Prior to 9-Sep-02: SB=Strong Buy; B=Buy; H=Hold; S=Sell; R=Restricted; NR=Not Rated

TER.TO Date	Closing Price (CAD)	Target Price (CAD)	Rating	Initiation/ Assumption
1/12/04	23.13	25	OUTPERFORM	X
11/5/04	25.8	26.5		
1/26/05	29.48		NEUTRAL	

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CSFB's distribution of stock ratings (and banking clients) is:

Global Ratings Distribution

Outperform/Buy*	37%	(56% banking clients)
Neutral/Hold*	44%	(56% banking clients)
Underperform/Sell*	17%	(43% banking clients)
Restricted	2%	

**For purposes of the NYSE and NASD ratings distribution disclosure requirements, our stock ratings of Outperform, Neutral, and Underperform most closely correspond to Buy, Hold, and Sell, respectively; however, the meanings are not the same, as our stock ratings are determined on a relative basis. (Please refer to definitions above.) An investor's decision to buy or sell a security should be based on investment objectives, current holdings, and other individual factors.*

See the Companies Mentioned section for full company names.

Price Target: (12 months) for (TER.TO)

Method: Dividend yield versus the 10 year government of Canada forecast bond yield.

Risks: Rapid rise in the 10-year government of Canada bond yield.

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COMPANY UPDATE

CREDIT SUISSE FIRST BOSTON

Equity Research Canada

Terasen Inc

TER.TO

TER: Adjustment to Tax Timing, No Impact on Full Year EPS Estimates

- **We are revising our 2005E quarterly EPS estimates to reflect the change in the timing of quarterly accounting of Terasen Gas income tax. The change has *no impact on company fundamentals and annual earnings*, only on the timing of its recognition.**

  Q1/05E EPS – from $0.77 to $0.67

  Q2/05E EPS – from $0.10 to $0.18

  Q3/05E EPS – from -$0.04 to $0.10

  Q4/05E EPS – from $0.65 to $0.53

- **We are maintaining our annual 2005E and 2006E EPS estimates of $1.49 and $1.59.**

- **For comparability purposes, we are also restating our quarterly 2004A EPS to reflect the timing of tax expense recognition. Our annual 2004A EPS stays the same at $1.39.**

  Q1/04A EPS – from $0.76 to $0.63

  Q2/04A EPS – from $0.09 to $0.16

  Q3/04A EPS – from -$0.03 to $0.08

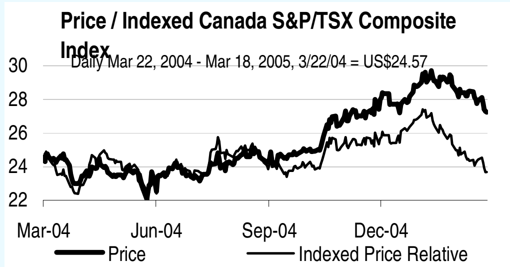
  Q4/04A EPS – from $0.58 to $0.52

- **We maintain our Neutral rating and $26.50 target price.**

Terasen is a diversified utility with oil pipelines, local gas distribution assets and water utilities.

Rating	**NEUTRAL***
Price (18 Mar 05)	**27.24 (C$)**
Target price (12 months)	**26.50 (C$)**
52 week high - low	**29.71 - 22.05**
Market cap. (C$m)	**2,861.51**
Enterprise value (C$m)	**6,071.21**
Region / Country	**Americas / Canada**
Sector	**Pipelines**
Analyst's Coverage Universe	**Pipelines and Utilities**
Weighting (vs. broad market)	**MARKET WEIGHT**
Date	**21 March 2005**

**** Stock ratings are relative to the coverage universe in each analyst's or each team's respective sector.***



On 03/18/05 the Canada S&P/TSX Composite Index index closed at 9,754.69

Year	12/04A	12/05E	12/06E
EPS (CSFB adj., C$)	1.39	1.49	1.59
Prev. EPS (C$)			
P/E (x)	19.6	18.3	17.1
P/E rel. (%)	NM	NM	NM
Q1 EPS	0.63	0.67	
Q2	0.16	0.18	
Q3	0.08	0.10	
Q4	0.52	0.53	

Number of shares (m)	105.05	IC (Current, C$m)	—
BV/Share (Current, C$)	14.34	EV/IC (x)	
Net Debt (Current, C$m)	2,963.9	Dividend (Current, C$m)	0.90
Net debt/Total cap. (Current)	66.3%	Dividend yield	3.3%

Year	12/04A	12/05E	12/06E
Revenues (C$m)	1,075.4	1,015.3	1,037.4
EBITDA (C$m)	803.4	635.9	625.4
OCFPS (C$)	2.83	2.82	2.63
P/OCF (x)	9.6	9.7	10.4
EV/EBITDA (x)	7.6	9.5	9.7
ROIC	10.8%	—	—

Source: Company data, CREDIT SUISSE FIRST BOSTON (CSFB) estimates

research team

Dominique Barker, CA, CFA
416 352 4594
dominique.barker@csfb.com

Peter Best
416 352 4585
peter.best@csfb.com

Richelle Embree
416 352 4584
richelle.embree@csfb.com

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Companies Mentioned *(Price as of 18 Mar 05)*

Terasen Inc (TER.TO, C$27.24, NEUTRAL, TP C$26.50, MARKET WEIGHT)

Disclosure Appendix

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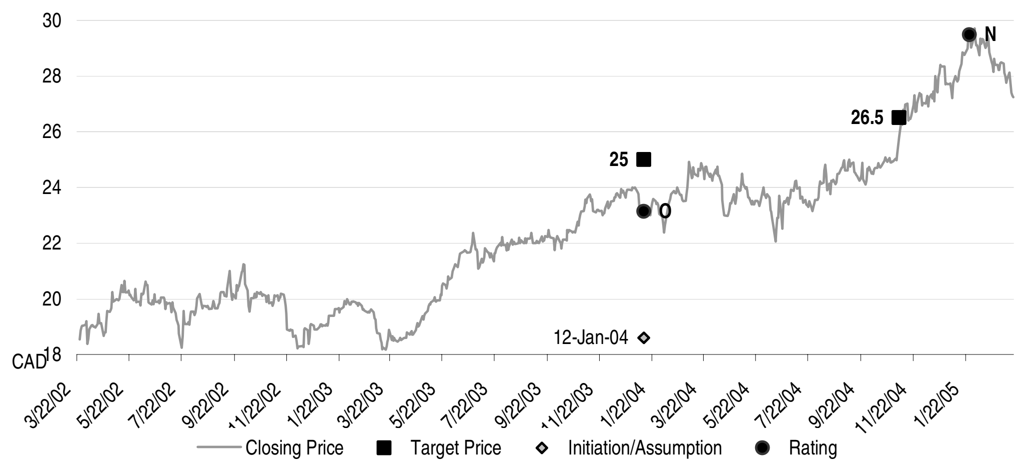
3-Year Price, Target Price and Rating Change History Chart for TER.TO



Current: O=Outperform; N=Neutral; U=Underperform; R=Restricted; NR=Not Rated
Prior to 9-Sep-02: SB=Strong Buy; B=Buy; H=Hold; S=Sell; R=Restricted; NR=Not Rated

TER.TO Date	Closing Price (CAD)	Target Price (CAD)	Rating	Initiation/ Assumption
1/12/04	23.13	25	OUTPERFORM	X
11/5/04	25.8	26.5		
1/26/05	29.48		NEUTRAL	

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Underperform:** The stock's total return is expected to underperform the industry average* by 10-15% or more over the next 12 months.

**The industry average refers to the average total return of the analyst's industry coverage universe (except with respect to Asia/Pacific, Latin America and Emerging Markets, where stock ratings are relative to the relevant country index, and CSFB HOLT Small and Mid-Cap Advisor stocks, where stock ratings are relative to the regional CSFB HOLT Small and Mid-Cap Advisor investment universe.*

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Overweight: Industry expected to outperform the relevant broad market benchmark over the next 12 months.

Market Weight: Industry expected to perform in-line with the relevant broad market benchmark over the next 12 months.

Underweight: Industry expected to underperform the relevant broad market benchmark over the next 12 months.

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Price Target: (12 months) for (TER.TO)

Method: Dividend yield versus the 10 year government of Canada forecast bond yield.

Risks: Rapid rise in the 10-year government of Canada bond yield.

See the Companies Mentioned section for full company names.

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COMPANY UPDATE

CREDIT SUISSE | FIRST BOSTON

Equity Research Canada

Terasen Inc

TER.TO

Terasen EPS Update

- **We are revising our quarterly 2005E EPS estimates for Terasen, but maintaining our annual 2005E and 2006E EPS estimates of $1.49 and $1.59, respectively.**

- **We previously estimated that the lower throughput volumes from Trans Mountain resulting from Alberta oil sands production outages would affect all four quarters of 2005, rather than impacting only Q1/05. The company clarified in its quarterly release that shipments on the Trans Mountain mainline system have returned to apportionment in April.**

- **Following are the quarterly estimate changes:**

  Q1/05A EPS – from $0.67E to $0.60A

  Q2/05E EPS – from $0.18 to $0.21

  Q3/05E EPS – from $0.10 to $0.13

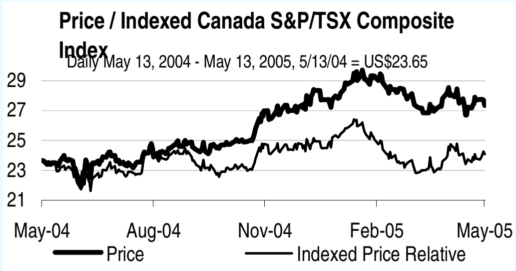
  Q4/05E EPS – from $0.53 to $0.55

- **We continue to like Terasen's fundamental story from a growth perspective but find the stock expensive at these levels. We maintain our Neutral rating and $26.50 target price, which implies 16.7x 2006 P/E and 9.7x 2006 P/CF.**

Terasen is a diversified utility with oil pipelines, local gas distribution assets and water utilities.

Rating	**NEUTRAL***
Price (13 May 05)	**27.33 (C$)**
Target price (12 months)	**26.50 (C$)**
52 week high - low	**29.71 - 22.05**
Market cap. (C$m)	**2,878.94**
Enterprise value (C$m)	**6,128.74**
Region / Country	**Americas / Canada**
Sector	**Pipelines**
Analyst's Coverage Universe	**Pipelines and Utilities**
Weighting (vs. broad market)	**MARKET WEIGHT**
Date	**16 May 2005**

**** Stock ratings are relative to the coverage universe in each analyst's or each team's respective sector.***



On 05/13/05 the Canada S&P/TSX Composite Index index closed at 9,278.45

Year	12/04A	12/05E	12/06E
EPS (CSFB adj., C$)	**1.39**	**1.49**	**1.59**
Prev. EPS (C$)			
P/E (x)	**19.6**	**18.3**	**17.2**
P/E rel. (%)	**NM**	**NM**	**NM**
Q1 EPS	**0.63**	**0.60**	
Q2	**0.16**	**0.21**	
Q3	**0.08**	**0.13**	
Q4	**0.52**	**0.55**	

Number of shares (m)	**105.34**	IC (Current, C$m)	**—**
BV/Share (Current, C$)	**13.47**	EV/IC (x)	
Net Debt (Current, C$m)	**2,969.9**	Dividend (Current, C$m)	**0.90**
Net debt/Total cap. (Current)	**67.5%**	Dividend yield	**3.3%**

Year	12/04A	12/05E	12/06E
Revenues (C$m)	**1,075.4**	**909.7**	**918.7**
EBITDA (C$m)	**803.4**	**603.9**	**609.9**
OCFPS (C$)	**2.83**	**2.66**	**2.73**
P/OCF (x)	**9.8**	**10.3**	**10.0**
EV/EBITDA (x)	**7.6**	**10.1**	**10.0**
ROIC	**10.8%**	**—**	**—**

Source: Company data, CREDIT SUISSE FIRST BOSTON (CSFB) estimates

research team

Dominique Barker, CA, CFA
416 352 4594
dominique.barker@csfb.com

Richelle Embree
416 352 4584
richelle.embree@csfb.com

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Companies Mentioned *(Price as of 13 May 05)*

Terasen Inc (TER.TO, C$27.33, NEUTRAL, TP C$26.50, MARKET WEIGHT)

Disclosure Appendix

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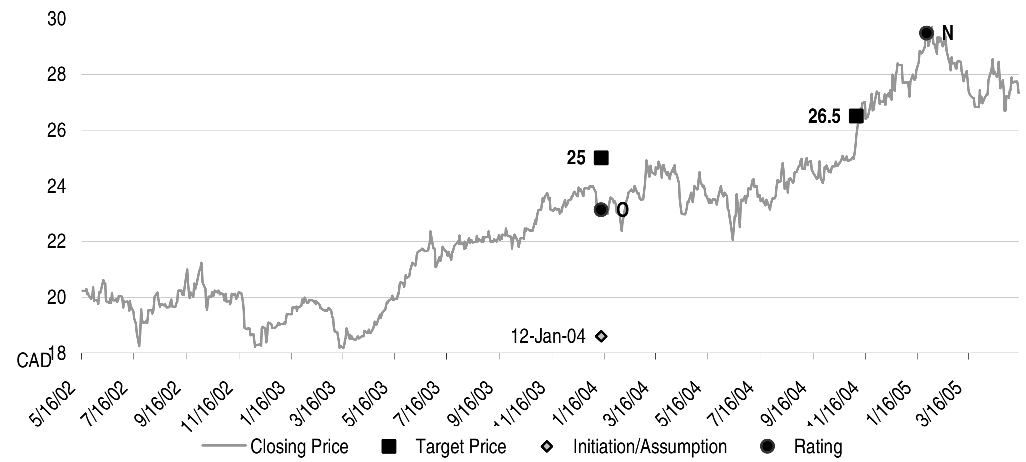
See the Companies Mentioned section for full company names.

3-Year Price, Target Price and Rating Change History Chart for TER.TO



Current: O=Outperform; N=Neutral; U=Underperform; R=Restricted; NR=Not Rated

Prior to 9-Sep-02: SB=Strong Buy; B=Buy; H=Hold; S=Sell; R=Restricted; NR=Not Rated

TER.TO Date	Closing Price (CAD)	Target Price (CAD)	Rating	Initiation/ Assumption
1/12/04	23.13	25	OUTPERFORM	X
11/5/04	25.8	26.5		
1/26/05	29.48		NEUTRAL	

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Neutral/Hold*	43%	(55% banking clients)
Underperform/Sell*	16%	(42% banking clients)
Restricted	3%	

**For purposes of the NYSE and NASD ratings distribution disclosure requirements, our stock ratings of Outperform, Neutral, and Underperform most closely correspond to Buy, Hold, and Sell, respectively; however, the meanings are not the same, as our stock ratings are determined on a relative basis. (Please refer to definitions above.) An investor's decision to buy or sell a security should be based on investment objectives, current holdings, and other individual factors.*

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COMPANY UPDATE

Terasen Inc

TER.TO

Opportunities Abound

- **We have recently returned from a roadtrip with Terasen management. As a result, we have increased confidence that there are real opportunities for stable growth in the short- and long-term. Growth will be driven from oil sands infrastructure needs. Terasen has a pipeline of approximately $4 billion worth of proposed projects for the next five years.**

- **Among the growth projects, the most material are 1) Corridor expansion (1 million bpd, $7 to 900 million investment) and 2) TransMountain expansion (75 kbpd expansion for $570 million with confidence, and possibly an additional 550 kbpd expansion for $1.7 to 2.0 billion, depending on the route taken). There are additional growth projects, but these are the most material. Refer to page 2 for a complete list of projects.**

- **We are increasing the probability of the TMX expansion winning over Enbridge's Gateway proposal from 50% to 75% because 1) it is staged, so matches oil sands production growth more closely; 2) we believe the market for incremental crude demand is the U.S., not Asia; 3) the southern route already exists, so we believe there will be less aboriginal land claim issues than any northern route proposals; 4) there is an incremental addition of 550 kbpd versus Gateway's 400 kbpd; 5) with a looped system, there is the possibility of having two separate quality pipelines (one crude, one refined product), a valuable proposition for the shippers. We do not eliminate the chances of Gateway proceeding, as we cannot ignore China's love of mega-projects.**

- **How will the growth be financed? We estimate Terasen will have a debt/cap level of 69% at year-end. The target level is 67 to 70%. Therefore, if the Corridor expansion proceeds (likely), we estimate Terasen will raise $200 million in equity to maintain 70% debt/cap.**

- **Risks in the short-term: renegotiation of the incentive tolling agreement, expected before year-end.**

- **Valuation: our target of $26.50 implies 18x 05 EPS. We believe the stock will stay expensive, owing to its attractive risk/return and therefore advise long-term investors to buy on share price weakness.**

Terasen is a diversified utility with oil pipelines, local gas distribution assets and water utilities.

research team

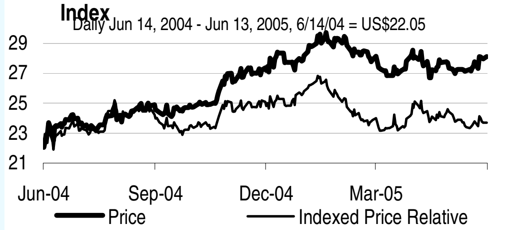
Dominique Barker, CA, CFA
416 352 4594
dominique.barker@csfb.com

Richelle Embree
416 352 4584
richelle.embree@csfb.com

Rating	**NEUTRAL***
Price (13 Jun 05)	**28.11 (C$)**
Target price (12 months)	**26.50 (C$)**
52 week high - low	**29.71 - 22.05**
Market cap. (C$m)	**2,961.11**
Enterprise value (C$m)	**6,210.91**
Region / Country	**Americas / Canada**
Sector	**Pipelines**
Analyst's Coverage Universe	**Pipelines and Utilities**
Weighting (vs. broad market)	**MARKET WEIGHT**
Date	**14 June 2005**

**** Stock ratings are relative to the coverage universe in each analyst's or each team's respective sector.***

Price / Indexed Canada S&P/TSX Composite Index



On 06/13/05 the Canada S&P/TSX Composite Index index closed at 9,802.67

Year	12/04A	12/05E	12/06E
EPS (CSFB adj., C$)	1.39	1.49	1.59
Prev. EPS (C$)			
P/E (x)	20.2	18.9	17.7
P/E rel. (%)	NM	NM	NM
Q1 EPS	0.63	0.60	
Q2	0.16	0.21	
Q3	0.08	0.13	
Q4	0.52	0.55	

Number of shares (m)	105.34	IC (Current, C$m)	—
BV/Share (Current, C$)	13.47	EV/IC (x)	
Net Debt (Current, C$m)	2,969.9	Dividend (Current, C$m)	0.90
Net debt/Total cap. (Current)	67.5%	Dividend yield	3.2%

Year	12/04A	12/05E	12/06E
Revenues (C$m)	1,075.4	909.7	918.7
EBITDA (C$m)	803.4	603.9	609.9
OCFPS (C$)	2.83	2.66	2.73
P/OCF (x)	9.8	10.6	10.3
EV/EBITDA (x)	7.7	10.3	10.2
ROIC	10.8%	—	—

Source: Company data, CREDIT SUISSE FIRST BOSTON (CSFB) estimates

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Growth Projects by Segment

We have summarized the list of projects in the following table, in order of our assessment of the probability of each proceeding.

Exhibit 1: Growth Project summary – total of approximately $4 billion in the pipeline

Segment	Project Description	Investment	Probability	Timing
Pipelines	Corridor expansion, 35 kbpd	$35 million	High	Fall 2005
Pipelines	Bison (42" pipeline), 1mm bpd	$700-900 million	High	In-service 2009
Pipelines	TransMountain expansion, 35 kbpd	$205 million	High	In-service 2006
Gas utility	LNG storage	$100 million	Medium/High	2005-6
Gas utility	Additional compression	$50 million	Medium/High	2005-7
Pipelines	TMX1, 40 kbpd	$365 million	Medium/High	In-service 2008
Gas utility	Whistler gas distribution	$35 million	Medium	For 2010 Olympics
Gas utility	Whistler ground source heat pump	$10 to 30 million	Medium	For 2010 Olympics
Pipelines	TMX2, 75 kbpd	$800-900 million	Medium	In-service 2009
Pipelines	TMX3, 475 kbpd	$0.9-1.1 billion	Medium	In-service 2009
Gas utility	Inland Pacific Connector	$300-500 million	Low	Long-term
Pipelines	Express buildout	?	Low	Long-term
Water	M&A	?	Medium	Ongoing

Source: Company data, CSFB estimates

In addition to these short- and medium-term growth projects, Terasen is interested in growing its water utilities business in the long-term. Terasen is looking to Aqua America (WTR, US$29.36, not rated) and California Water (CWT, US$36.84, not rated) as models for this segment, both of which trade at very high multiples (in the 25-30 P/E range). Terasen currently has approximately $200 million of capital committed to water utilities, and operates over 90 systems in over 50 communities. While we are cautious of management's foray into this relatively new area, we think the water segment will provide long-term growth for the company once pipeline expansion opportunities decline (in 5-7 years).

M&A

Terasen indicated it is interested in acquiring financially accretive assets that are

1) In the same geographic area as the rest of Terasen's operations (Pacific NorthWest, which Terasen describes as British Columbia, Washington, Oregon, Alberta);
2) Regulated utilities, including natural gas distribution, electric distribution, electric transmission, and water distribution.

We expect continued small acquisitions (<$50 million) on the water utilities side.

How Will Terasen Finance the Growth?

We estimate that Terasen produces approximately $350 million of free cash flow, after dividend payment. The debt/cap for Terasen is currently 68%.

Exhibit 2: Terasen Free Cash – Approximately $350 million per year

	1999	2000	2001	2002	2003	2004	2005	2006	2007
EBIT	308	309	356	403	436	447	457	463	468
Depreciation	83	86	95	116	133	147	150	150	150
Less: Maintenance Capex	-75	-75	-75	-75	-75	-75	-75	-75	-75
Less: Cash Tax	-46	-56	-46	-53	-50	-70	-76	-78	-79
Less: dividends	-45	-51	-56	-67	-86	-93	-100	-102	-102
Change in Working Capital	-50	108	-138	7	-73	15	30	0	0
Total Free Cash Flow	176	321	136	331	286	371	386	359	363

Source: Company data, CSFB estimates

Assuming the Corridor and the TransMountain expansions proceed (including TMX1), Terasen will need approximately $1.4 billion. Assuming Terasen maintains a 70% debt/cap ratio, we estimate Terasen will need to raise approximately $2-300 million.

Why not use financial partners for Greenfield?

The reason Terasen would not bring in its financial partners, Ontario Teachers and OMERS, on a Greenfield project such as Corridor or TransMountain, is because it is financially advantageous to equity shareholders to invest in new projects at book value, assuming the value of the project translates to a multiple of book (Terasen currently trades at approximately 2.0x); we estimate a valuation bump of 1.3 – 1.4x book value for projects such as Corridor and TMX. Terasen would invite its financial partners to participate in M&A situations where the cost of capital of the group is reduced, due to the non-taxable status of the pension funds.

Income Trusting the Gas Utility?

There is currently a case before the British Columbia Utilities Commission (BCUC) that proposes to put Pacific Northern Gas (PNG-UN.TO, not rated) into an income trust. This is a regulated gas utility in northern BC that has had financial difficulty since its largest customer, Methanex, shut down its methanol plant at Kitimat for 12 months in 2000. PNG has been financially challenged ever since, and believes a recapitalization to an income trust structure would improve its financial flexibility and access to capital markets.

The BCUC initially refused the income trust idea for PNG, but PNG has redrawn a slightly different proposal (one where rates charged to customers are based on actual rather than deemed capital structure) that is currently being considered by the BCUC. A decision is expected this summer; if the BCUC accepts the new income trust structure, it opens the door for Terasen Gas and Terasen Gas Vancouver Island to be placed in an income trust structure. It is our belief that the tax savings that would result from such conversion would have to be shared by investors and customers to be acceptable to the BCUC.

Using 10x 05E EBITDA and 30% equity gives an equity value to the gas utilities of $1.25 billion.

Uncertainty in TransMountain Incentive Tolling Settlement

The five-year agreement with shippers on TransMountain expires December 31, 2005. At the time of the original negotiation, Terasen took volume risk and therefore the tolls were higher than they otherwise would have been under a take-or-pay agreement. The TransMountain System has done very well since the original agreement, and currently runs at full capacity. Therefore, the returns on the capital invested are quite high (estimated ROE in the mid to high teens).

We believe Terasen will negotiate a settlement with producers; Terasen would like to come to a final agreement prior to year-end, but can only commence negotiations in a meaningful way with the Canadian Association of Petroleum Producers (CAPP) after Enbridge completes its negotiations with the Association, which is expected imminently. Enbridge has been without a settlement since the end of 2004.

The likely outcome is that TransMountain tolls will be negotiated downward, but the earnings stream will be less risky as the entire pipeline moves to firm service. In addition, there will likely be an expansion on the System.

Other Regulatory

Terasen is going back to the regulator to re-examine the capital structure of Terasen Gas in British Columbia. Currently, Terasen Gas has an equity thickness of 33%, with allowed ROE of 9.0%. The ROE is calculated annually using forecasted 10-year Government of Canada bond yields. Last year, the forecasted bond yield was 5.65%; using a bond yield of 4.5% implies an allowed ROE of only 8.5%. Therefore, Terasen would like to offset the potential loss of earnings due to the declining bond yields with an increase in equity thickness. Terasen believes it is in a good position to do so, given recent regulatory decisions in Alberta and nationally that have bumped up the equity thickness. An increase in equity thickness to 35% would offset the impact of the decline in ROE.

Overall View

We like Terasen for its fundamental growth story, geographic focus, low risk (excellent relationship with BC regulator on gas utilities) and ability to access lower cost capital with financial partners Ontario Teachers and OMERS. The one important takeaway we had from spending time with management was the long-term view on the business; as pipeline growth opportunities dissipate, the company is preparing itself to replace that growth with the water utilities segment.

Companies Mentioned *(Price as of 13 Jun 05)*

Aqua America Inc (WTR, $29.35)
California Water Service (CWT, $36.79)
Enbridge Inc. (ENB.TO, C$33.61, NEUTRAL, TP C$29.50, MARKET WEIGHT)
Terasen Inc (TER.TO, C$28.11, NEUTRAL, TP C$26.50, MARKET WEIGHT)

Disclosure Appendix

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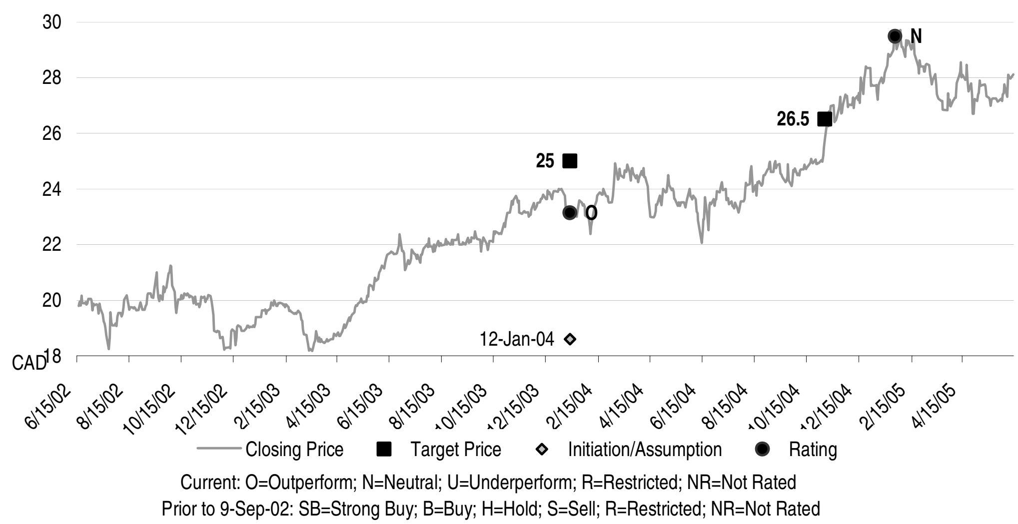
3-Year Price, Target Price and Rating Change History Chart for TER.TO



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Equity Research Canada

Terasen Inc

TER.TO

FORECAST INCREASE

Clean Q, Opportunities for Growth Abound

- **Terasen reported earnings of $0.24 (after adjusting for $1 million tax benefit to Express that relates to Q1 but was included in Q2, and mark-to-market pretax gain of $3.3 million). This compares to our estimate, and consensus, of $0.21.**

- **The main reason for the outperformance is lower operations and maintenance (O&M) expenses in gas distribution (down 4% year on year, and $2 million (or 4%) less than our expectation), as well as higher volumes and better results on the petroleum transportation side.**

- **We are raising our 2005 EPS estimates from $1.49 to $1.60 and our 2006 EPS estimates from $1.59 to $1.80.**

- **We see many growth opportunities for Terasen into the long-term. Please see our report dated June 14, 2005 entitled "Opportunities Abound" where we highlight current projects along with our assessment of its probability of proceeding.**

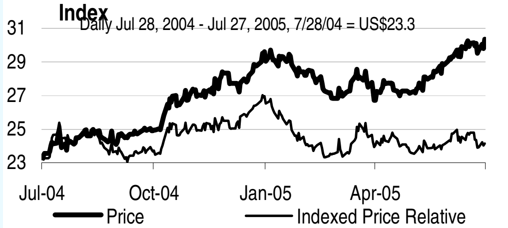
- **We are raising our target price from $26.50 to $30. Our new target implies a 06E P/E of 17x. The target implies a dividend yield of 3%, or 70% of a theoretical 10-year bond yield of 4.25%. We are maintaining our Neutral rating on the stock.**

Terasen is a diversified utility with oil pipelines, local gas distribution assets and water utilities.

Rating	**NEUTRAL***
Price (27 Jul 05)	**30.35 (C$)**
Target price (12 months)	**30.00 (C$)**
52 week high - low	**30.35 - 23.15**
Market cap. (C$m)	**3,197.07**
Enterprise value (C$m)	**6,412.77**
Region / Country	**Americas / Canada**
Sector	**Pipelines**
Analyst's Coverage Universe	**Pipelines and Utilities**
Weighting (vs. broad market)	**MARKET WEIGHT**
Date	**28 July 2005**

**** Stock ratings are relative to the coverage universe in each analyst's or each team's respective sector.***

Price / Indexed Canada S&P/TSX Composite Index



On 07/27/05 the Canada S&P/TSX Composite Index index closed at 10,516.23

Year	12/04A	12/05E	12/06E
EPS (CSFB adj., C$)	1.39	1.60	1.80
Prev. EPS (C$)		1.49	1.59
P/E (x)	21.8	19.0	16.9
P/E rel. (%)	129.1	138.0	131.9
Q1 EPS	0.63	0.60	
Q2	0.16	0.24	
Q3	0.08	0.16	
Q4	0.52	0.60	

Number of shares (m)	105.34	IC (Current, C$m)	—
BV/Share (Current, C$)	13.47	EV/IC (x)	—
Net Debt (Current, C$m)	2,969.9	Dividend (Current, C$m)	0.90
Net debt/Total cap. (Current)	67.5%	Dividend yield	3.0%

Year	12/04A	12/05E	12/06E
Revenues (C$m)	—	—	—
EBITDA (C$m)	—	—	—
OCFPS (C$)	—	—	—
P/OCF (x)	—	—	—
EV/EBITDA (x)	—	—	—
ROIC	10.8%	—	—

Source: Company data, CREDIT SUISSE FIRST BOSTON (CSFB) estimates

research team

Dominique Barker, CA, CFA
Research Analyst
416 352 4594
dominique.barker@csfb.com

Richelle Embree
Research Analyst
416 352 4584
richelle.embree@csfb.com

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FLASH FLASH FLASH FLASH FLASH FL

Investment Summary

Companies Mentioned *(Price as of 27 Jul 05)*

Terasen Inc (TER.TO, C$30.35, NEUTRAL, TP C$26.50, MARKET WEIGHT)

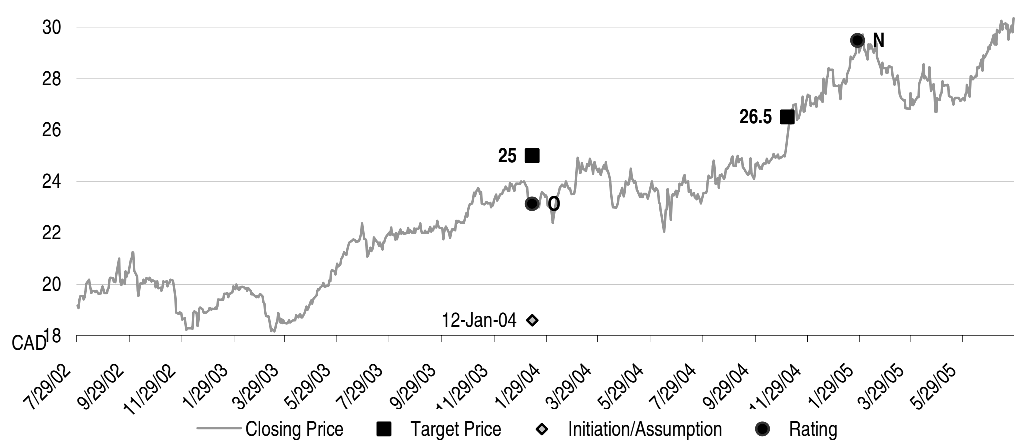
Disclosure Appendix

Important Global Disclosures

I, Dominique Barker, certify that (1) the views expressed in this report accurately reflect my personal views about all of the subject companies and securities and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this report.

See the Companies Mentioned section for full company names.

3-Year Price, Target Price and Rating Change History Chart for TER.TO



Current: O=Outperform; N=Neutral; U=Underperform; R=Restricted; NR=Not Rated
Prior to 9-Sep-02: SB=Strong Buy; B=Buy; H=Hold; S=Sell; R=Restricted; NR=Not Rated

TER.TO Date	Closing Price (CAD)	Target Price (CAD)	Rating	Initiation/ Assumption
1/12/04	23.13	25	OUTPERFORM	X
11/5/04	25.8	26.5		
1/26/05	29.48		NEUTRAL	

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Neutral: The stock's total return is expected to be in line with the industry average* (range of ±10%) over the next 12 months.

Underperform:** The stock's total return is expected to underperform the industry average* by 10-15% or more over the next 12 months.

**The industry average refers to the average total return of the analyst's industry coverage universe (except with respect to Asia/Pacific, Latin America and Emerging Markets, where stock ratings are relative to the relevant country index, and CSFB HOLT Small and Mid-Cap Advisor stocks, where stock ratings are relative to the regional CSFB HOLT Small and Mid-Cap Advisor investment universe.*

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Overweight: Industry expected to outperform the relevant broad market benchmark over the next 12 months.

Market Weight: Industry expected to perform in-line with the relevant broad market benchmark over the next 12 months.

Underweight: Industry expected to underperform the relevant broad market benchmark over the next 12 months.

*****_CSFB HOLT Small and Mid-Cap Advisor stocks do not have coverage universe weightings._

***An analyst's coverage universe consists of all companies covered by the analyst within the relevant sector.*

****The broad market benchmark is based on the expected return of the local market index (e.g., the S&P 500 in the U.S.) over the next 12 months.*

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Global Ratings Distribution

Outperform/Buy*	39%	(54% banking clients)
Neutral/Hold*	43%	(54% banking clients)
Underperform/Sell*	15%	(46% banking clients)
Restricted	3%	

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See the Companies Mentioned section for full company names.

Price Target: (12 months) for (TER.TO)

Method: Dividend yield versus the 10 year government of Canada forecast bond yield.

Risks: Rapid rise in the 10-year government of Canada bond yield.

See the Companies Mentioned section for full company names.

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Equity Research Canada

Terasen Inc

TER.TO

Good Marriage

- **Kinder Morgan is acquiring Terasen for approximately $35.75 (see details inside on three options for shareholders), representing a premium of approximately 20% over the 20 day average closing price, and a premium of approximately 14% to the prior day's close. We are increasing our target to $35.75 (from $30.00), reflecting the implied takeover value for Terasen shares.**

- **Financial metrics: this represents a multiple of 11.8x last twelve months (LTM) EBITDA, and 25x LTM P/E. This is a full price.**

- **Rival bidders? While the break fee is only C$75 million (= 2% of equity value or 1.1% of entity value), we do not believe a rival bid is in the offing. We think Enbridge and Terasen would be an excellent fit (both heavily exposed to oil sands region of Alberta, both have gas distribution), but we do not believe shippers would allow the deal to happen, as it would limit competition and choice for them – we measure the probability of a takeover by Enbridge as remote. The other possibility is financial buyers. Ontario Teachers and OMERS, two of the largest Canadian pension funds, are partners with Terasen on the Express pipeline. We would measure the probability of a bid by financial buyers as low based on full valuation and limited synergies.**

- **Good marriage: we think Kinder Morgan is looking to deploy capital (current debt/cap low 40% range, BBB rating); Terasen has a need for capital (debt/cap 68%, BBB rating) as we estimate Terasen needs approximately C$4 billion in capital over the next five years.**

- **Impact on rest of sector: this confirms our view that the market for incremental oil sands production is the U.S., not China. We do not believe Enbridge's Gateway project (400 kbpd) proceeds and believe approximately $2 in Enbridge's share price is attributed to Gateway.**

- **Timing: Terasen expects the deal to close by the end of 2005. Please see our summary table of hurdles to pass and risks.**

Terasen is a diversified utility with oil pipelines, local gas distribution assets and water utilities.

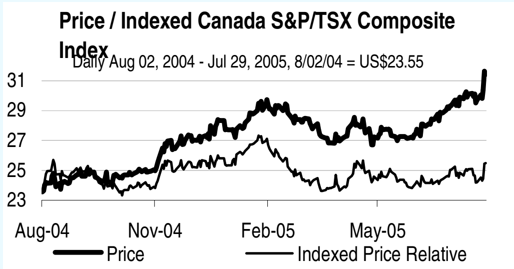
research team

Dominique Barker, CA, CFA
Research Analyst
416 352 4594
dominique.barker@csfb.com

Richelle Embree
Research Analyst
416 352 4584
richelle.embree@csfb.com

Rating	**NEUTRAL***
Price (29 Jul 05)	**31.40 (C$)**
Target price (12 months)	**35.75 (C$)**
52 week high - low	**31.64 - 23.44**
Market cap. (C$m)	**3,307.68**
Enterprise value (C$m)	**6,557.48**
Region / Country	**Americas / Canada**
Sector	**Pipelines**
Analyst's Coverage Universe	**Pipelines and Utilities**
Weighting (vs. broad market)	**MARKET WEIGHT**
Date	**01 August 2005**

**** Stock ratings are relative to the coverage universe in each analyst's or each team's respective sector.***



On 07/29/05 the Canada S&P/TSX Composite Index index closed at 10,422.93

Year	12/04A	12/05E	12/06E
EPS (CSFB adj., C$)	**1.39**	**1.60**	**1.80**
Prev. EPS (C$)			
P/E (x)	**22.6**	**19.6**	**17.4**
P/E rel. (%)	**133.6**	**133.0**	**120.7**
Q1 EPS	**0.63**	**0.60**	
Q2	**0.16**	**0.24**	
Q3	**0.08**	**0.16**	
Q4	**0.52**	**0.60**	

Number of shares (m)	**105.34**	IC (Current, C$m)	**—**
BV/Share (Current, C$m)	**13.47**	EV/IC (x)	
Net Debt (Current, C$m)	**2,969.9**	Dividend (Current, C$m)	**0.90**
Net debt/Total cap. (Current)	**67.5%**	Dividend yield	**2.9%**

Year	12/04A	12/05E	12/06E
Revenues (C$m)	—	—	—
EBITDA (C$m)	—	—	—
OCFPS (C$)	—	—	—
P/OCF (x)	—	—	—
EV/EBITDA (x)			
ROIC	**10.8%**	—	—

Source: Company data, CREDIT SUISSE FIRST BOSTON (CSFB) estimates

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Investment Summary

Three Options for Shareholders

Kinder Morgan, Inc. (KMI, $88.86) is offering three choices for Terasen shareholders: 1) C$35.75 in cash; 2) 0.3331 shares of KMI common stock; 3) C$23.25 cash plus 0.1165 shares of KMI stock. See summary below, based on August 1 closing prices (KMI at US$88.86, CAD/USD at 1.2124), which value Terasen shares at approximately $35.75.

Exhibit 1: Based on August 1 closing prices

	Option 1 (cash)	Option 2 (shares)	Option 3 (cash and shares)
Exchange ratio	NA	0.3331	0.1165
Cash portion	$35.75	NA	$23.25
Stock portion	NA	$35.77	$12.66
Implied TER price	**$35.75**	**$35.77**	**$35.91**
Implied LTM P/E	24.9x	24.9x	25.0x
Implies LTM EV/EBITDA	11.8x	11.8x	11.8x

Source: Company data, CSFB estimates

Growth Opportunities Abound

Terasen has a pipeline of approximately C$4 billion worth of proposed projects for the next five years.

Exhibit 2: Summary of what is in the Pipeline

Segment	Project	Investment (millions)	Probability	Timing
Pipelines	Corridor expansion, 35 kbpd	$35	High	Fall 2005
Pipelines	Bison (42" pipeline), 1mm bpd	$700-$900	High	In-service 2009
Pipelines	TransMountain expansion, 35 kbpd	$210	High	In-service 2007
Gas utility	Additional compression	$50	Medium/High	2005-7
Pipelines	TMX1, 40 kbpd	$365	Medium/High	In-service 2008
Gas utility	Whistler gas distribution	$35	Medium	For 2010 Olympics
Gas utility	Whistler ground source heat pump	$10-$30	Medium	For 2010 Olympics
Pipelines	TMX2, 75 kbpd	$800-900	Medium	In-service 2009
Pipelines	TMX3, 475 kbpd	$900-$1100	Low	In-service 2009
Gas utility	Inland Pacific Connector	$300-500	Low	Long-term
Gas utility	LNG storage	$100	Low	2007-8
Pipelines	Express buildout	?	Low	Long-term
Water	M&A	?	Medium	On-going

Source: Company data, CSFB estimates

Therefore, Kinder Morgan will have substantial growth opportunities via Terasen for the short, medium and long-term. Terasen would have been unable to complete these projects without tapping the equity markets.

Timing of Approvals with Risk Assessment

Terasen expects the deal to close by December 2005. The only risks we see, and we would consider them moderate, is:

1) The US Federal Trade Commission (FTC), which is difficult for us to predict; and

2) The British Columbia regulator, where Terasen is the monopoly local gas distribution company. There is a modest risk this becomes a political issue in British Columbia.

Exhibit 3: Various Hurdles and Probability of Issue or Delay

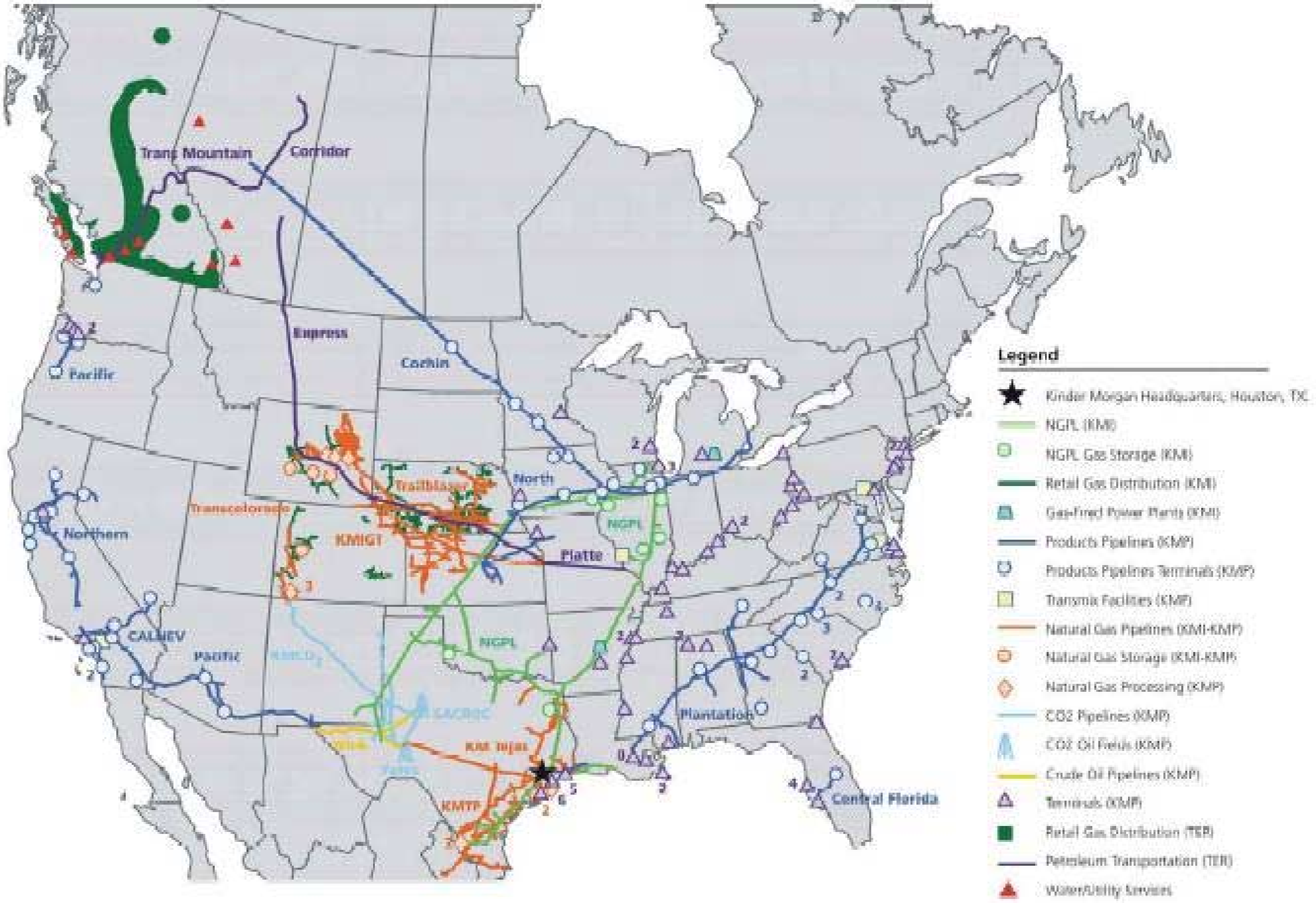
	Jurisdiction	Probability of issue or delay	Comment
Canada Competition Bureau	Canada	low	Regulated, will likely be deferred to regulators
US competition (Hart-Scott-Rodino)	US	medium	Terasen only has two pipelines in the US; but FTC is unpredictable
Investment Canada	Canada	low	No cultural issues; Duke takeover of Westcoast Energy is a good precedent
British Columbia Utilities Commission	British Columbia	medium	Duke's purchase of Westcoast provides precedent (Centra and PNG); BCUC will be interested in Kinder Morgan's ability to serve customer base well. Could become a political issue.
Local water regulators	Various communities with water utilities managed by TER	low	May be issues in jurisdictions where KMI has local gas distribution, but not aware of any
National Energy Board	Canada	low	Duke takeover of Westcoast is precedent
FERC	US	low	Not expected to have any issues

Source: Company data, CSFB estimates

The boards of both Terasen and Kinder Morgan have unanimously approved the transaction. 75% of shareholders must vote in favour of the deal at a special meeting to be held in October 2005.

Map of Operations

Exhibit 4: Terasen and Kinder Morgan Map of operations



Source: Terasen

Companies Mentioned *(Price as of 01 Aug 05)*

Enbridge Inc. (ENB.TO, C$35.30, NEUTRAL, TP C$31.00, MARKET WEIGHT)
Kinder Morgan, Inc. (KMI, $88.86, NOT RATED)
Terasen Inc (TER.TO, C$31.40, NEUTRAL, TP C$35.75, MARKET WEIGHT)

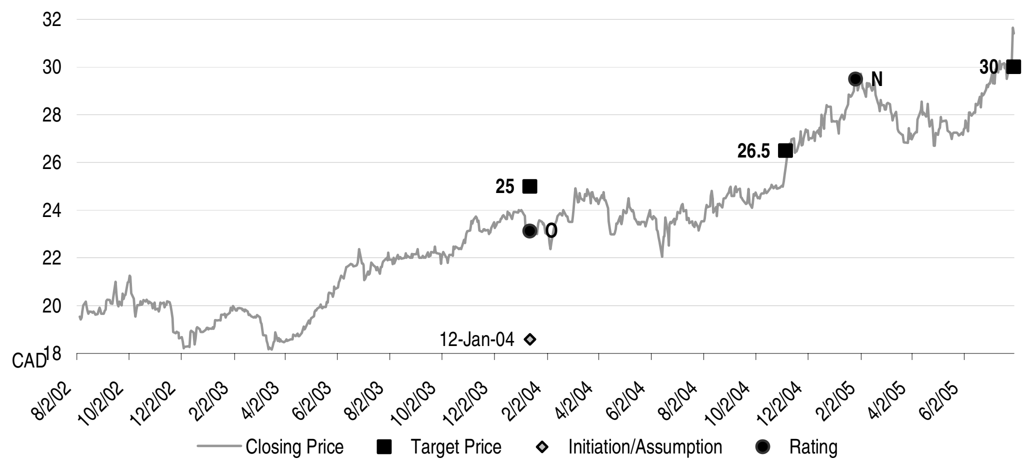
Disclosure Appendix

Important Global Disclosures

I, Dominique Barker, certify that (1) the views expressed in this report accurately reflect my personal views about all of the subject companies and securities and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this report.

See the Companies Mentioned section for full company names.

3-Year Price, Target Price and Rating Change History Chart for TER.TO



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Prior to 9-Sep-02: SB=Strong Buy; B=Buy; H=Hold; S=Sell; R=Restricted; NR=Not Rated

TER.TO Date	Closing Price (CAD)	Target Price (CAD)	Rating	Initiation/ Assumption
1/12/04	23.13	25	OUTPERFORM	X
11/5/04	25.8	26.5		
1/26/05	29.48		NEUTRAL	
7/29/05	31.4	30		

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Outperform: The stock's total return is expected to exceed the industry average* by at least 10-15% (or more, depending on perceived risk) over the next 12 months.

Neutral: The stock's total return is expected to be in line with the industry average* (range of ±10%) over the next 12 months.

Underperform:** The stock's total return is expected to underperform the industry average* by 10-15% or more over the next 12 months.

**The industry average refers to the average total return of the analyst's industry coverage universe (except with respect to Asia/Pacific, Latin America and Emerging Markets, where stock ratings are relative to the relevant country index, and CSFB HOLT Small and Mid-Cap Advisor stocks, where stock ratings are relative to the regional CSFB HOLT Small and Mid-Cap Advisor investment universe.*

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Overweight: Industry expected to outperform the relevant broad market benchmark over the next 12 months.

Market Weight: Industry expected to perform in-line with the relevant broad market benchmark over the next 12 months.

Underweight: Industry expected to underperform the relevant broad market benchmark over the next 12 months.

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***An analyst's coverage universe consists of all companies covered by the analyst within the relevant sector.*

****The broad market benchmark is based on the expected return of the local market index (e.g., the S&P 500 in the U.S.) over the next 12 months.*

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Global Ratings Distribution

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Restricted	3%	

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Price Target: (12 months) for (TER.TO)

Method: Dividend yield versus the 10 year government of Canada forecast bond yield.

Risks: Rapid rise in the 10-year government of Canada bond yield.

See the Companies Mentioned section for full company names.

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Merrill Lynch

Comment

Canada
Natural Gas-Pipelines

28 July 2005

Andrew C. Fairbanks
Research Analyst, MLPF&S
(1) 212 449-6697
andrew_fairbanks@ml.com

Kieran McCabe
Research Analyst, MLPF&S
(1) 212 449-0983

Terasen Inc.

Rebound in Oil Sands Volumes

NEUTRAL

Reason for Report: Earnings Commentary

Volatility Risk: LOW

Price: **C$31.64**

Estimates (Dec)	2004A	2005E	2006E
EPS:	$1.39	$1.48	$1.57
P/E:	22.8x	21.4x	20.2x
GAAP EPS:	$1.42	$1.54	$1.57
GAAP P/E:	22.3x	20.5x	20.2x
EPS Change (YoY):		6.5%	6.1%
Cash Flow/Share:	$2.94	$2.91	$2.82
Price/Cash Flow:	10.8x	10.9x	11.2x
Dividend Rate:	$0.76	$0.85	$0.90
Dividend Yield:	2.4%	2.7%	2.8%

Opinion & Financial Data

Investment Opinion:	A-2-7
Mkt. Value / Shares Outstanding (mn):	$3,353.8 / 106
Book Value/Share (Jun-2005):	$14.01
Price/Book Ratio:	2.3x
ROE 2005E Average:	10.6%
Total Debt / Capital:	67.9%
Est. 5 Year EPS Growth:	6.0%
Est. 5 Year Dividend Growth:	4.0%

Stock Data

52-Week Range:	C$31.20-C$23.10
Symbol / Exchange:	YTER / Toronto Stock Exchange
Institutional Ownership-Vickers:	NA

Highlights:

- ***TER reported clean seasonal operating earnings of C$25.6mm or C$0.24/share in 2Q05 compared to C$104.7mm or C$0.17/share in 2Q04.*** Including mark-to-market hedging gains of C$3.9mm (AT) related to natural gas derivatives at Clean Energy, earnings would be C$29.5mm or C$0.28/share.
- **Petroleum Transportation** earned C$20.9mm, up from C$16.2mm in 2Q04. Higher throughput on the Trans-Mountain mainline and Express System were the main reasons for the increase in earnings. TransMountain throughput on the Canadian mainline increased 8.3%.
- **Natural Gas Distribution** posted earnings of C$7.7mm compared to C$5.1mm in 2Q04. The segment was impacted by the lower allowable rate of return, which was partially offset by operating efficiencies at Terasen Gas.
- **Water and Utility Services earned** C$3.8mm compared to C$2.6mm in 2Q04. Growth in the base business and the contribution from TER's 50% interest in Fairbanks Sewer and Water Inc were the main reasons for the improvement in earnings year over year.
- **Other Activities** for 2Q05 posted a loss of C$2.9mm compared to a loss of C$6.0mm in the year ago period. Adjusting for a C$3.9mm AT hedging gain at Clean Energy (TER holds a 45.0% interest) the loss was C$6.8mm.
- ***No change to our 2005 EPS estimates of C$1.48 or our 2006 EPS estimate of C$1.57.***
- ***No change to our Neutral (A-2-7) opinion.***

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*iQprofile*SM Terasen Inc.

Key Income Statement Data (Dec)	2003A	2004A	2005E	2006E	2007E
(CAD Millions)					
Sales	**1,877**	**1,957**	**1,811**	**1,906**	**1,887**
Gross Profit	NA	NA	NA	NA	NA
Sell General & Admin Expense	(314)	(303)	(302)	(321)	(296)
EBITDA	**508**	**539**	**563**	**613**	**588**
Depreciation & Amortization	(133)	(147)	(138)	(130)	(132)
Net Interest & Other Income	(168)	(167)	(171)	(171)	(168)
Tax Expense / Benefit	(59)	(69)	(91)	(101)	(93)
Net Income (Adjusted)	**138**	**147**	**157**	**166**	**156**
Average Fully Diluted Shares Outstanding	105	106	106	106	106
Key Cash Flow Statement Data					
Net Income (GAAP)	147	156	163	211	196
Depreciation & Amortization	133	147	138	130	132
Change in Working Capital	(23)	46	18	0	0
Deferred Taxation Charge	9	0	0	0	0
Other Adjustments, Net	0	0	0	0	0
Cash Flow from Operations	**268**	**349**	**318**	**341**	**327**
Capital Expenditure	(223)	(154)	(277)	(226)	(229)
(Acquisition) / Disposal of Investments	(207)	(58)	0	0	0
Other Cash Inflow (Outflow)	(2)	52	(3)	0	0
Cash Flow from Investing	**(432)**	**(160)**	**(280)**	**(226)**	**(229)**
Share Issue / (Repurchase)	10	15	6	0	0
Cost of Dividends Paid	(86)	(93)	(95)	(99)	(103)
Cash Flow from Financing	159	(163)	38	(70)	(53)
Net Debt	2,905	2,811	2,989	3,018	3,068
Change in Net Debt	**240**	**(111)**	**51**	**(16)**	**5**
Key Balance Sheet Data					
Property, Plant & Equipment	3,882	3,893	4,018	4,114	4,211
Other Non-Current Assets	456	482	509	509	509
Trade Receivables	404	349	280	280	280
Cash & Equivalents	2	20	92	92	92
Other Current Assets	171	228	243	243	243
Total Assets	**4,915**	**4,971**	**5,142**	**5,238**	**5,335**
Long-Term Debt	2,301	2,167	2,091	2,121	2,170
Other Non-Current Liabilities	170	209	227	227	228
Short-Term Debt	606	665	989	989	989
Other Current Liabilities	408	434	382	382	382
Total Liabilities	3,486	3,475	3,690	3,720	3,770
Total Equity	1,430	1,496	1,451	1,518	1,566
Total Equity & Liabilities	**4,915**	**4,971**	**5,142**	**5,238**	**5,335**
***iQmethod*SM – Business Performance**					
Return On Capital Employed	6.3%	6.2%	6.0%	7.0%	6.5%
Return On Equity	9.9%	10.0%	10.6%	11.2%	10.1%
Operating Margin	20.0%	20.0%	23.5%	25.3%	24.2%
Free Cash Flow	45	195	41	115	98
***iQmethod*SM – Quality of Earnings**					
Cash Realization Ratio	1.9x	2.4x	2.0x	2.1x	2.1x
Asset Replacement Ratio	1.7x	1.0x	2.0x	1.7x	1.7x
Tax Rate	28.6%	30.7%	36.0%	32.3%	32.2%
Net Debt-to-Equity Ratio	203.2%	187.9%	206.0%	198.8%	196.0%
Interest Cover	2.1x	2.4x	2.5x	2.8x	2.7x

*iQmethod*SM

iQmethod is the set of Merrill Lynch standard measures that serve to maintain global consistency under three broad headings: Business Performance, Quality of Earnings, and Valuation.

The key features of ***iQmethod*** are:

- A consistently structured, detailed, and transparent methodology.
- Guidelines to maximize the effectiveness of the comparative valuation process, and to identify some common pitfalls.

*iQdatabase*SM

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*iQmethod*SM Measures Definitions

Business Performance	
Return On Capital Employed =	[NOPAT = (EBIT + Interest Income) * (1 - Tax Rate) + Goodwill Amortization] / [Avg (Total Assets – Current Liabilities + ST Debt + Accumulated Goodwill Amortization)]
Return On Equity =	[Net Income] / [Avg Shareholders' Equity]
Operating Margin =	[Operating Profit] / [Sales]
Earnings Growth =	[Expected 5-Year CAGR From Latest Actual] or the analysts' estimate of the sustainable growth rate
Free Cash Flow =	[Cash Flow From Operations – Total Capex]
Quality of Earnings	
Cash Realization Ratio =	[Cash Flow From Operations] / [Net Income]
Asset Replacement Ratio =	[Capex] / [Depreciation]
Tax Rate =	[Tax Charge] / [Pre-Tax Income]
Net Debt-To-Equity Ratio =	[Net Debt = Total Debt, Less Cash & Equiv] / [Total Equity]
Interest Cover =	[EBIT] / [Interest Expense]
Valuation	
Price / Book Value =	[Current Sh Price] / [Shareholders' Equity / Current Basic Sh]
Dividend Yield =	[Annualized Declared Cash Div] / [Current Sh Price]

2Q05 Results

TER reported clean seasonal operating earnings of C$25.6mm or C$0.24/share in 2Q05 compared to C$104.7mm or C$0.17/share in 2Q04. Including mark-to-market hedging gains of C$3.9mm (AT) related to natural gas derivatives at Clean Energy, earnings would be C$29.5mm or C$0.28/share.

Operating income in Petroleum transportation rose from the year ago period as volumes on the TransMountain pipeline returned to full capacity. In addition, the capacity expansion at the Express system also impacted results positively. Natural gas distribution results were also higher compared to the year ago period as operating efficiencies and customer growth at Terasen Gas offset a lower allowed rate of return on equity in 2005. Operating income at Water and Utility Services increased by C$1.2mm from continued growth in the base waterworks and the contribution from Fairbanks Sewer & Water (50% interest).

TER's Board of Directors declared a regular common dividend per share of C$0.225 per quarter (annual dividend of C$0.90/share).

Management indicated on its conference call that the company remains comfortable with an earnings growth rate of 6% in 2005.

Segment Breakdown

Petroleum Transportation earned C$20.9mm, up from C$16.2mm in 2Q04. Higher throughput on the Trans-Mountain mainline and Express System were the main reasons for the increase in earnings. TransMountain throughput on the Canadian mainline increased 8.3%.

The Express System contributed C$7.6mm in 2Q05 compared to C$3.2mm in 2Q04.

Natural Gas Distribution posted earnings of C$7.7mm compared to C$5.1mm in 2Q04. The segment was impacted by the lower allowable rate of return, which was partially offset by operating efficiencies at Terasen Gas.

Water and Utility Services earned C$3.8mm compared to C$2.6mm in 2Q04. Growth in the base business and the contribution from TER's 50% interest in Fairbanks Sewer and Water Inc (FSW – no relation to the analyst) were the main reasons for the improvement in earnings year over year.

Other Activities for 2Q05 posted a loss of C$2.9mm compared to a loss of C$6.0mm in the year ago period. Adjusting for a C$3.9mm AT hedging gain at Clean Energy (TER holds a 45.0% interest) the loss was C$6.8mm.

Key Developments

■ Vancouver Island Gas Supply

On February 16, 2005, the BCUC approved the C$100mm LNG storage facility at Vancouver Island. The decision was subject to several conditions including the execution of a long-term Transportation Service Agreement (TSA) with BC Hydro backed by the capacity demand requirements of the Duke Point Power project. On June 17th, BC Hydro decided to abandon the Duke Point Power project on Vancouver Island. As a result, TER believes the TGVI's proposed storage facility has been delayed. TER plans to re-file the project with the BCUC later this year as it believes there is strong customer demand growth that will support the expansion of the natural gas distribution system, including the LNG storage facility.

■ Corridor Expansion

TER is working with Shell Canada and its AOSP partners. TER expects to begin engineering, environmental and consultation activities on the project soon. TER plans to file an application for the Corridor Pipeline Expansion Project with the AEUB and Alberta Environment in the fall of 2005. Pending regulatory approval, TER hopes to begin construction in late 2006.

■ TMX

TER continues to progress with work on the TMX expansion. The company filed an application in July with the National Energy Board (NEB) for the pump station expansion. This expansion would increase capacity to 260,000 b/d from 225,000 b/d at a cost of C$210mm. TER expects to hold an open season later this summer for the Anchor Loop Project (a 30-inch pipeline loop between Hinton, Alberta and Valemount, BC at a cost of C$365mm).

Investment Summary

No change to our 2005 EPS estimates of C$1.48 or our 2006 EPS estimate of C$1.57.

No change to our Neutral opinion. Nonetheless, we very much like the strategy, assets, and management of the company. While we like TER's current dividend yield of 3%, low risk business model, strategy, and disciplined corporate culture, we regard the shares as being close to fairly valued. TER has generated a strong, steady long-term track record of EPS and dividend growth.

Analyst Certification

I, Andrew Fairbanks, hereby certify that the views expressed in this research report accurately reflect my personal views about the subject securities and issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or view expressed in this research report.

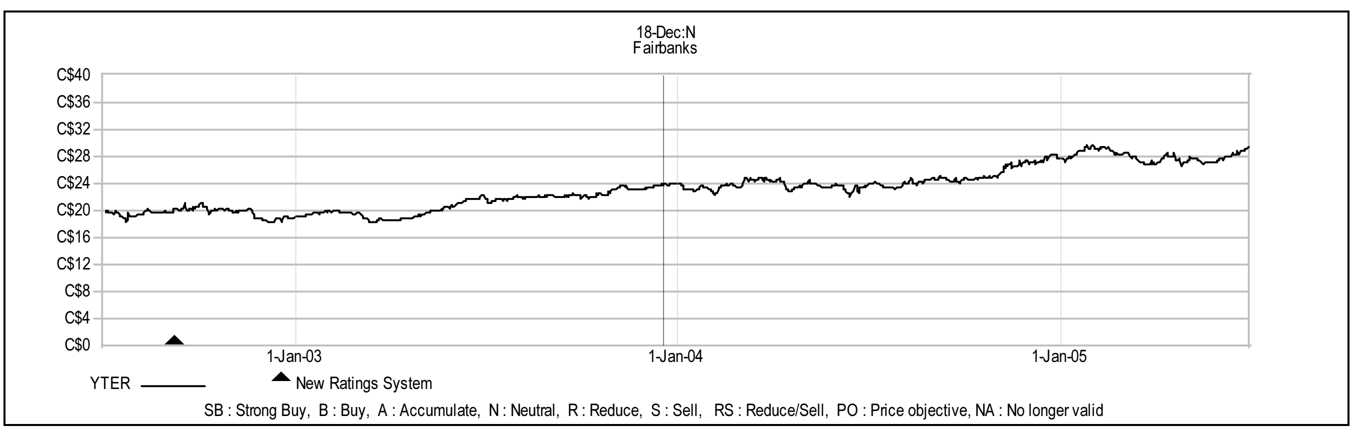
Chart 1: Terasen Summary Earnings Model

Earnings, AT C$mn	1997	1998	1999	2000	2001	2002	2003	2004	2005E	2006E
Natural Gas Transmission	45	52	52	59	68	92	99	96	103	106
Petroleum Transportation	20	23	20	22	27	29	56	71	73	79
Other	(0)	(4)	3	(2)	(11)	(12)	(17)	(20)	(19)	(20)
Sub-Total	**65**	**71**	**74**	**79**	**85**	**110**	**138**	**147**	**156**	**166**
Special Adjustments	(14)	-	7	30	-	(4)	(5)	3	7	
Total	**51**	**71**	**81**	**109**	**85**	**106**	**133**	**150**	**163**	**166**
EPS (Continuing Diluted)	**0.81**	**0.92**	**0.97**	**1.03**	**1.10**	**1.26**	**1.31**	**1.39**	**1.48**	**1.57**
Special Items	(0.18)	-	0.09	0.39	-	(0.05)	(0.05)	0.03	0.07	
EPS (Reported Diluted)	**0.63**	**0.92**	**1.06**	**1.42**	**1.10**	**1.21**	**1.26**	**1.42**	**1.54**	**1.57**
Shares O/S - FD	80	77	77	77	77	87	105	106	106	106
Divends per Share	**0.49**	**0.55**	**0.58**	**0.61**	**0.65**	**0.69**	**0.76**	**0.85**	**0.90**	**0.90**
Cash Flow	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005E**	**2006E**
Net Income (bef Capital Sec)	51	71	81	113	91	113	139	156	167	166
DD&A	78	85	83	86	95	116	133	147	138	130
Deferred Taxes	(7)	1	10	(18)	10	11	9	(1)	0	0
Other	-	(1)	0	(4)	(1)	5	8	8	3	-
Cash Flow (fr. Ops.)	**122**	**156**	**174**	**176**	**195**	**244**	**290**	**311**	**308**	**295**
Net Acquis/sales	21	(3)	(21)	28	(15)	315	209	6	3	-
PP&E Spending	130	129	164	621	470	396	223	154	277	226
Capital Spending	151	126	142	648	455	711	432	160	280	226
Dividends	39	42	45	51	56	67	86	93	95	99
Free Cash Flow	**(68)**	**(11)**	**(13)**	**(523)**	**(316)**	**(533)**	**(228)**	**57**	**(67)**	**(29)**
Op. CFPS (Diluted)	1.52	2.03	2.28	2.30	2.54	2.80	2.76	2.94	2.91	2.79
EBITDA	375	398	416	452	523	611	673	769	805	881
EBITDA/Net Interest Expense	3.3x	3.3x	3.4x	3.8x	3.5x	3.8x	3.8x	4.6x	4.7x	5.2x
Net Debt	1,467	1,581	1,525	1,999	2,455	2,667	2,905	2,811	2,989	3,018
Net Debt/ Total Cap	71.4%	72.8%	70.7%	70.6%	74.5%	66.1%	67.0%	65.0%	66.0%	65.2%
Effective Tax Rate (%)	46.7%	45.3%	36.3%	7.1%	38.1%	36.0%	34.0%	30.7%	36.0%	32.3%
Return on Avg. Equity	11.1%	12.1%	12.2%	11.0%	10.3%	10.0%	9.9%	10.0%	10.8%	11.2%
ROACE (%) - oper Income	8.7%	9.1%	9.0%	7.9%	7.6%	7.4%	7.5%	7.2%	7.4%	7.3%

Source: Company reports and Merrill Lynch estimates

Important Disclosures

YTER Price Chart



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Investment Rating Distribution: Energy Group (as of 30 June 2005)

Coverage Universe	Count	Percent	Inv. Banking Relationships*	Count	Percent
Buy	60	44.12%	Buy	20	33.33%
Neutral	72	52.94%	Neutral	21	29.17%
Sell	4	2.94%	Sell	0	0.00%

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1 August 2005

Andrew C. Fairbanks
Research Analyst, MLPF&S
(1) 212 449-6697
andrew_fairbanks@ml.com

Kieran McCabe
Research Analyst, MLPF&S
(1) 212 449-0983

Terasen Inc.

Kinder Morgan Agrees to Buy TER; Change to "No Opinion"

NO RATING

Reason for Report: Change to No Opinion

Company

YTER; C$31.40; A-2-7 to 6

EPS (Dec): 2004A C$1.39; 2005E C$1.48; 2006E C$1.57
P/E (Dec): 2004A 22.6x; 2005E 21.2x; 2006E 20.0x

GAAP EPS (Dec): 2004A C$1.42; 2005E C$1.54; 2006E C$1.57
GAAP P/E (Dec): 2004A 22.1x; 2005E 20.4x; 2006E 20.0x

Event

Kinder Morgan (KMI) announced that it will acquire Terasen for a total purchase price, including the assumption of debt, of approximately US$5.6 billion (C$6.9 billion). The transaction has been approved by the Board of Directors of Terasen and Kinder Morgan as well as a special committee of independent directors created by the Terasen board to oversee the process.

The transaction requires the approval of 75% of Terasen shareholders who will vote at a special meeting to be held on or before October 31, 2005. For each TER share, Terasen shareholders will be able to elect from three options: 1) C$35.75 in cash, 2) 0.3331 share of KMI common stock, or 3) C$23.25 in cash plus 0.1165 shares of KMI common stock. There will be a conference call to discuss the transaction by Kinder Morgan at 8:30 am ET and Terasen at 10:00 AM ET.

Analysis

The prorated value of the offer is C$35.91 per TER share based on KMI's share price and C$/US$ exchange rates as of July 29th, representing a premium of 14% over Friday's closing price of TER's shares. The offer valuation equates to 24 times our prior 2005 EPS estimates and 23x our old 2006 EPS.

Recommendation

Based on today's announcement, we believe that the stock is no longer trading on equity fundamentals. Therefore, we are changing our investment opinion on the stock to a 6 (No Rating).

Investors should no longer rely on Merrill Lynch's prior estimates or ratings.

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Investors should consider this report as only a single factor in making their investment decision.

Refer to important disclosures on pages 3 to 4. Analyst Certification on page 2.

Analyst Certification

I, Andrew Fairbanks, hereby certify that the views expressed in this research report accurately reflect my personal views about the subject securities and issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or view expressed in this research report.

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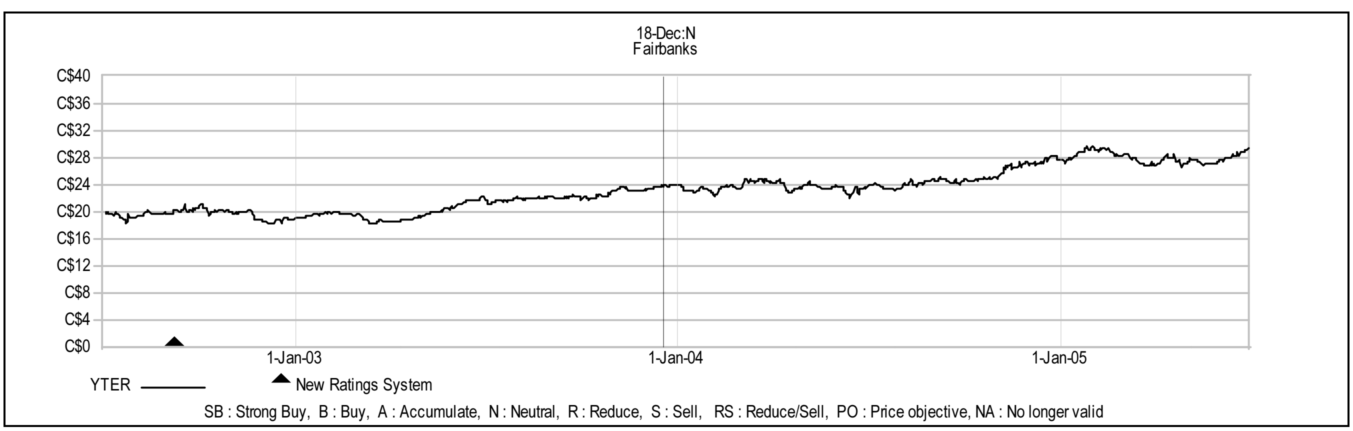
YTER Price Chart



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NATIONAL BANK FINANCIAL

February 18, 2005

The NBF Daily Bulletin
Gas Utilities

Terasen Inc.

2004 Results a Penny Higher Than Expected

Petroleum Transportation Leads Y/Y Growth

TER (T)	**Cdn$29.34**
Stock Rating:	**Underperform** (Unchanged)
Target:	**Cdn$24.50** (Was $24.15)
Risk Rating:	**Average** (Unchanged)

Stock Data:	
52-week High-Low (Canada)	$22.05 - $29.71
Bloomberg/Reuters: Canada	TER CN / TER.TO

(Year-End Dec 31)	**2004a**	**2005e**	**2006e**
EPS	$1.43	$1.51	$1.58
P/E	19.4x	19.4x	18.6x
EPS Change Y/Y	9.2%	5.6%	4.6%
Book Value	$13.04	$13.65	$14.33
P/BV	2.1x	2.1x	2.0x
Dividend Yield	3.0%	3.1%	3.1%

Financial Data:	
Shares Outstanding (mln)	105.2
Book Value per Share	$13.04
Market Capitalization (mln)	$3 086
Price/Book Ratio	2.3x
Debt/Total Cap.	65%
Dividend per share	$0.90
Dividend Yield	3.07%

Industry Rating: Underweight
(NBF Economics & Strategy Group)

Company Profile:
TER is a holding company and its largest investment is Terasen Gas (TG), British Columbia's largest diversified natural gas distributor. It also owns Terasen Gas-Vancouver Island (TGVI). TER also controls Terasen Pipelines-Trans Mountain (TMP), Canada's second-largest petroleum pipeline. TER entered gas transmission in British Columbia in November 2000, and on May 1, 2003 began commercial shipping on the Corridor Pipeline (CP) for Shell Canada.

Winfried Fruehauf, PHD - (416) 869-7932
winfried.fruehauf@nbfinancial.com

Associate: Ramin Burney - (416) 869-7933
ramin.burney@nbfinancial.com

HIGHLIGHTS

- **Q4 2004 reported earnings:**
  $53.9 million or $0.51 per share vs. $50.9 million or $0.49 per share year-over-year (y/y). For 2004, earnings increased to $149.8 million or $1.43 per share vs. $136.1 million or $1.31 per share y/y. **2004 EPS were $0.01 higher than our estimate.**

- **Earnings from Natural Gas Distribution declined y/y…**
  …as a result of lower allowed RROE for both Terasen Gas (TG) and Terasen Gas-Vancouver Island (TGVI), which more than offset operating efficiencies achieved from the integration of their operations.

- **Petroleum Transportation, and Water and Utility Services businesses contributed y/y earnings improvements of 26% and 61%, respectively.**
  High levels of throughput continued at Trans Mountain Pipe Line (TMP) and at the Express System (ES), while Corridor Pipeline (CP) contributed a full year of solid earnings.

- **TER's Board of Directors approved a 7.1% increase in the quarterly common share dividend to $0.225 from $0.21 per share.**

- **We have raised our target price slightly to $24.50 from $24.15 but…**
  …still believe that TER is over-priced relative to its peers and its own dividend and earnings metrics. Hence, our Underperform rating is sustained.

Stock Performance

NATIONAL BANK FINANCIAL

Assessment

TER's diversified investments have been able to supplement earnings from its relatively mature gas distribution business. The recent expansion of Trans Mountain Pipe Line's (TMP) mainline capacity and the expected completion of the Express System (ES) expansion by April 2005, as well as potential improvements in its water and utility services business will provide some earnings growth in 2005. But earnings growth beyond 2005, will hinge on the success of TER's planned petroleum-pipeline projects that will most surely encounter stiff competition from the likes of Enbridge Inc. (TSX; NYSE-ENB) and possibly TransCanada Corp. (TSX; NYSE-TRP).

We continue to view TER's common share prices as quite over-priced relative to share prices of Canadian pipelines and utilities. **Our Underperform rating is sustained.**

Fourth-Quarter 2004 Highlights

Q4 2004 reported earnings: $53.9 million or $0.51 per share vs. $50.9 million or $0.49 per share y/y. Earnings from Petroleum Transportation, and from Water and Utility Services improved y/y, while Natural Gas Distribution posted lower earnings y/y.

Segmented Reported Earnings ($mln)	Q4 2004	Q4 2003
Natural Gas Distribution	$42.6	$44.8
Petroleum Transportation	$19.9	$17.9
Water and Utility Services	$0.7	$0.4
Other Activities	$(9.3)	$(8.8)
Earnings applicable to common shares	**$53.9**	**$50.9**

Source: Terasen Inc.

Natural Gas Distribution

- **Q4 2004 natural gas distribution earnings: Earnings of $42.6 million vs. $44.8 million y/y.** In 2004, earnings decreased to $95.9 million from $98.8 million in 2003. Earnings were negatively impacted by the lower allowed RROE for 2004 for Terasen Gas (TG) (9.15% vs. 9.42% in 2003) and Terasen Gas-Vancouver Island (TGVI) (9.65% vs. 9.92% in 2003), and the introduction of the 50/50 over-earnings incentive sharing mechanism which arose from the PBR settlement that came into effect on Jan. 1, 2004. This more than offset $4.1 million of operating efficiencies achieved from the integration of TG and TGVI operations. For 2005, the allowed RROE for TG is 9.03%, and TGVI is 9.53%.
- Starting in Q4 2004, Terasen Gas' income tax expense was determined by applying the effective annual tax rate to the pre-tax income in the quarter as opposed to the previous method of allocating annual tax expense based on budgeted sales revenue for the four quarters. Earnings for every quarter of 2004 were restated but the change had no impact on the total 2004 fiscal year results.
- On Feb. 16, 2005, the British Columbia Utilities Commission (BCUC) approved TGVI's proposed $100 million LNG storage facility (1 bcf of natural gas-equivalent capacity) near Nanaimo, B.C. The approval is subject to various conditions including the execution of a long-term Transportation Service Agreement (TSA) with B.C. Hydro which yesterday received BCUC approval to enter into an energy purchase contract with developers of a 262-MW electricity plant in the same area. However, construction of the LNG facility or the electricity plant is not assured.

Petroleum Transportation

- **Q4 2004 petroleum transportation earnings: $19.9 million vs. $17.9 million y/y.** For 2004, earnings jumped to $70.9 million from $56.2 million in 2003. The y/y improvement resulted due to high levels of throughput at Trans Mountain Pipe Line (TMP) and the Express System (ES), and a full year contribution from the Corridor Pipeline (CP).

- **TMP's Q4 2004 earnings increased to $11.2 million from $10 million y/y.** For 2004, earnings were $39.4 million vs. $35.8 million. The y/y improvement was due to throughput increases of 9% on the Canadian mainline (236,100 barrels per day [b/d] vs. 216,100) and 68% on the U.S. mainline (91,700 b/d vs. 54,600), as well as lower operating and maintenance costs. A 27,000 b/d expansion of TMP ($19 million cost) was completed in early October 2004.
- **The Express System (ES) contributed in Q4 2004 $4.9 million vs. $3.9 million y/y.** For 2004, earnings increased to $15.9 million from $9.7 million in 2003. Earnings increased y/y as mostly as a result of higher throughput (175,300 b/d from 171,200 b/d a year ago). A foreign exchange hedging transaction of balance-sheet items placed in late 2003 has been able to reduce earnings volatility on ES. Expansion of ES is on target for an in-service date of April 2005. Total system capacity will increase by 108,000 b/d to 280,000 b/d at a cost of about US$100 million, but earnings improvements are expected to be relatively modest because of ship-or-pay arrangements.
- On Jan. 31, 2005, Terasen Pipelines announced that it had received strong support from 17 different parties including existing and new customers who participated in the TMX Project's Expression of Interest process. It now plans to proceed with an Open Season in summer 2005. However, support from residents adjacent to the right-of-way is not assured.
- The TMX Project proposes a staged expansion of the existing Trans Mountain system (225,000 b/d capacity) between Edmonton, Alberta and Burnaby, B.C. The expansion consists of the looping of the existing pipeline to existing facilities in Burnaby, B.C. and/or could include the extension of Trans Mountain through the B.C. Interior to a potential new VLCC capable port on the B.C. coast. However, passage of VLCC through the Strait of Juan de Fuca is not assured environmentally.
- TER's initial expansion phase (TMX1), subject to final commercial arrangements and regulatory approvals, would increase the system's capacity to 300,000 b/d from 225,000 b/d by the end of 2008. Further stages of the expansion would bring the capacity to 850,000 b/d. The new capacity would allow additional transportation from Alberta's tar sands to the West Coast and Asian markets. TER Pipelines will now attempt to finalize a tolling framework with customers which will lead to the formal Open Season. However, we view transhipments of petroleum from TER's marine terminal to Kitimat/Prince Rupert and, thence, to East Asia as costly and time-consuming.
- TER's TMX Project is, in part, in direct competition with **Enbridge Inc.'s (TSX-ENB)** proposed $2.5 billion Gateway Project. We believe that ENB's proposal has more support and a better probability of succeeding. ENB is expected to sign commitments by mid-2005 for about 80% of the planned 400,000 b/d capacity. ENB is also prepared to lower its equity stake in the pipeline to no less than 51%. To the extent that refinery markets in Washington State (and possibly California) are concerned, there is likely to be room for incremental pumping capacity; however, we view looping requiring additional rights-of-way as a material challenge to TMX, and hasten to add that shipper and refiner support is one thing, but the NIMBY-syndrome is quite another.
- So far, TER has not addressed the latter publicly, which we view as the litmus test of TER's expansion plans. The NIMBY syndrome covers not only pipeline expansion, but also tanker, especially VLCC, traffic in the Straits of Georgia and Juan de Fuca.

Water and Utility Services

- **Q4 2004 water and utility services earnings: $0.7 million vs. $0.4 million y/y.** Earnings from this segment are typically stronger in the second and third quarters, and are weaker in first and fourth quarters reflecting seasonal patterns of new construction. For 2004, earnings increased to $6.6 million from $4.1 million, with $1.2 million of the earnings growth attributable to the July 31, 2004 acquisition of a 50% interest in the Fairbanks Sewer and Water Inc. (FSW) for $40.8 million and other minor acquisitions, and $1.3 million due to organic growth in existing businesses. TER expects this business to deliver one-third of its annual growth objectives of 6%.

Other Activities

- **Other Activities** (including Terasen International, TER's 45% interest in Clean Energy, and corporate interest and administration charges), **lost $9.3 million in Q4 2004 vs. a loss of $8.8 million y/y.** This quarter's higher loss was due to lower tax recovery. For 2004, net loss increased to $23.6 million from $23 million in 2003 due to lower tax recovery offset by lower corporate and financing costs, as well as a $3.3 million (after-tax) gain at Clean Energy from its price risk management activities.

Financial and Outlook

- **Capital Expenditures**: Q4 2004: $49.6 million vs. $63.6 million in Q4 2003. 2004: $154.4 million vs. $222.9 million in 2003. Projected 2005 capital expenditures are about $350 million including: **Natural Gas Distribution ($240 million)** - the acquisition of the Coastal Facilities buildings ($50 million); the Fraser River crossing ($20 million); the purchase and upgrade of the Texada Island compressor station ($15 million); and initial capital expenditures on the construction of the LNG storage facility on Vancouver Island ($23 million). **Petroleum Transportation** ($50 million) – the TMX Project, and Corridor Pipeline de-bottlenecking. **Water & Utility Services ($50 million)** – for organic expansion and minor water acquisitions.
- **Cash from Operations**: Q4 2004: $40.7 million vs. $32.2 million y/y. 2004: $342 million vs. $269.8 million in 2003.
- TER's Board of Directors approved a 7.1% increase in the quarterly common share dividend to $0.225 from $0.21 per share.
- **TER's growth forecast is 6% using the 2004 EPS base of $1.40 (excluding Clean Energy's $3.3 million after-tax gain).** TER expects TMP to have weaker throughput in Q1 2005, due to the impact of production outages by producers such as Shell, Syncrude and Suncor, and two refinery turnarounds.

Valuation

For the 2006 calendar year, we are estimating EPS of $1.58; DPS of $1.02; retained EPS of $0.56; a retained EPS multiple of 10x; and a nominal long-term corporate bond yield of 6.75%, tax-effected to 5.40%. The support price is $18.89 and the residual price is $5.60, for a target price of $24.50.

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PRIMARY STOCK RATING: NBF has a three-tiered rating system that is relative to the coverage universe of the particular analyst. Here is a brief description of each: **Outperform –** The stock is expected to outperform the analyst's coverage universe over the next 12 months; **Sector Perform –** The stock is projected to perform in line with the sector over the next 12 months; **Underperform –** The stock is expected to underperform the sector over the next 12 months.
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NATIONAL BANK FINANCIAL

May 5, 2005

The NBF Daily Bulletin
Gas Utilities

Terasen Inc.

Q1 2005 Results Slightly Lower Than Expected

Temporary Weakness In Petroleum Transportation Depresses Results

TER (T)	**Cdn$27.45**
Stock Rating:	**Underperform** (Unchanged)
Target:	**Cdn$24.95** (Was $24.50)
Risk Rating:	**Average** (Unchanged)

Stock Data:	
52-week High-Low (Canada)	$22.05 - $29.71
Bloomberg/Reuters: Canada	TER CN / TER.TO

(Year-End Dec 31)	2004a	2005e	2006e
EPS	$1.43	$1.51	$1.58
P/E	19.4x	18.2x	17.4x
EPS Change Y/Y	9.2%	5.6%	4.6%
Book Value	$13.04	$13.65	$14.33
P/BV	2.1x	2.0x	1.9x
Dividend Yield	3.0%	3.3%	3.3%

Financial Data:	
Shares Outstanding (mln)	105.4
Book Value per Share	$13.75
Market Capitalization (mln)	$2 894
Price/Book Ratio	2.0x
Debt/Total Cap.	68%
Dividend per share	$0.90
Dividend Yield	3.28%

HIGHLIGHTS

- **Q1 2005 reported earnings: $66.3 million or $0.63 per share vs. $67.9 million or $0.65 per share year-over-year (y/y). EPS was one penny lower than our and the Street's estimate.**

- **Earnings from Petroleum Transportation fell sharply to $12.7 million from $18.3 million y/y, mostly due to a weak contribution from Trans Mountain Pipe Line (TMP)…** TMP's throughput dropped 35.72% y/y as a result of maintenance turnarounds at refineries connected to TMP and temporary production outages in the Alberta tar sands which reduced supply.

- **Improved earnings from Natural-Gas (Gas) Distribution ($55.7 mln vs. $54.7 mln) and Water and Utilities Services ($0.8 mln vs. nil), as well as a decrease in operating losses at Other Activities managed to offset most of the weakness in Petroleum Transportation.**

- **Operating efficiencies and customer growth at Terasen Gas (TG) and Terasen Gas-Vancouver Island (TGVI) more than offset the lower allowed RROE for 2005.**

- **We continue to note that TER is over-priced relative to its peers, based on dividend and retained-earnings metrics. Hence, we sustain our Underperform rating.**

Stock Performance

Industry Rating: Underweight
(NBF Economics & Strategy Group)

Company Profile:
TER is a holding company and its largest investment is Terasen Gas (TG), British Columbia's largest diversified natural gas distributor. It also owns Terasen Gas-Vancouver Island (TGVI). TER also controls Terasen Pipelines-Trans Mountain (TMP), Canada's second-largest petroleum pipeline. TER entered gas transmission in British Columbia in November 2000, and on May 1, 2003 began commercial shipping on the Corridor Pipeline (CP) for Shell Canada.

Winfried Fruehauf, PhD - (416) 869-7932
winfried.fruehauf@nbfinancial.com

Associate: Ramin Burney - (416) 869-7933
ramin.burney@nbfinancial.com

Assessment – *no earth-shattering developments*

We continue to view TER's common share prices as quite over-priced relative to share prices of Canadian pipelines and utilities, as evidenced by a price-to-retained-earnings multiple that far exceeds fundamentals. **Hence, we are sustaining our Underperform rating.**

First-Quarter 2005 Highlights

Q1 2005 reported earnings: $66.3 million or $0.63 per share vs. $67.9 million or $0.65 per share y/y. EPS was one penny lower than our and the Street's estimate.

Earnings decreased y/y as **Petroleum Transportation** earnings fell sharply to $12.7 million from $18.3 million y/y, mostly due to a weak contribution from **Trans Mountain Pipe Line (TMP)**. TMP's throughput dropped 35.72% y/y as a result of maintenance turnarounds at refineries connected to TMP, and temporary production outages in the Alberta oil sands which reduced supply. Improved earnings from **Gas Distribution** ($55.7 million vs. $54.7 million) and **Water and Utilities Services** ($0.8 mln vs. nil), as well as a decrease in operating losses at **Other Activities** managed to offset most of the weakness in Petroleum Transportation.

Segmented Reported Earnings ($mln)	Q1 2005	Q1 2004
Natural Gas Distribution	$55.7	$54.7
Petroleum Transportation	$12.7	$18.3
Water and Utility Services	$0.8	-
Other Activities	$(2.9)	$(5.1)
Earnings applicable to common shares	**$66.3**	**$67.9**
Source: Terasen Inc.		

Gas Distribution

- **Q1 2005 natural gas distribution earnings: Earnings of $55.7 million vs. $54.7 million y/y.** Operating efficiencies and strong customer growth at Terasen Gas (TG) and Terasen Gas-Vancouver Island (TGVI) more than offset the lower allowed RROE for 2005. For 2005, TG's RROE is 9.03% vs. 9.15% in 2004, and TGVI's 9.53% vs. 9.65% in 2004.
- Higher revenues and cost of gas y/y reflected customer growth during the quarter and the cost of gas charged to customers. Increased operation and maintenance expenses were partially offset by improved operating efficiencies related to the operational integration of TG and TGVI. Customer additions during the quarter for TG and TGVI were 2,345 and 1,049, respectively, driven by strong economic conditions and housing activity in B.C.
- On Feb. 16, 2005, the British Columbia Utilities Commission (BCUC) approved TGVI's proposed $100 million LNG storage facility (1 bcf of gas-equivalent capacity) near Nanaimo, B.C. The approval is subject to various conditions including the execution of a long-term Transportation Service Agreement (TSA) with B.C. Hydro. TGVI is working with B.C. Hydro to obtain a TSA to serve the Duke Power Point Project on Vancouver Island. However, construction of the LNG facility or the electricity plant is not assured.

Petroleum Transportation

- **Q1 2005 petroleum transportation earnings: $12.7 million vs. $18.3 million y/y.** Earnings fell sharply due to a lower earnings contribution from all three pipelines but primarily the **Trans Mountain Pipe Line (TMP).**
- **TMP's Q1 2005 earnings decreased to $5.4 million from $10.4 million** as throughput dropped 35.72% y/y as a result of maintenance turnarounds at refineries connected to TMP, and temporary production outages in the Alberta oil sands which reduced supply. Throughput decreased 29% y/y on the Canadian mainline (170,000 barrels per day [b/d] vs. 240,400 b/d), and 52% y/y on the U.S. mainline (44,500 b/d vs. 93,300 b/d). **However, this drop in throughput is not expected to recur during the balance of 2005. TMP**

has been running at full capacity during April and had to apportion nominations for April and May 2005.

- **The Corridor Pipeline (CP) earnings contribution decreased to $3.6 million from $3.9 million y/y** as a result of a lower RROE for 2005. TER has been discussing with Shell and its partners in the Athabasca Oil Sands Project on the potential expansion of CP to 300,000 b/d from 155,000 b/d for 2009 with 90,000 b/d increments every two years thereafter. The expansion would occur in phases with the first phase (already approved by the CP Shippers' Committee) increasing capacity by about 35,000 b/d by adding pumping capacity with a fall 2005 in-service date, at a cost of $6.5 million; and the second phase (under review) adding 110,000 b/d by 2009 at a cost of $700-800 million. TER is also looking at increasing the capacity past the 500,000 b/d level.
- **However, in our view, what complicates sharing of CP's capacity is Shell's apprehension about potential degradation of its bitumen by lower-quality bitumen of third parties.**
- **The Express System (ES) contributed $3.7 million vs. $4.0 million y/y.** Earnings decreased y/y due to the same temporary production outages in the Alberta tar sands which reduced supply and reduced TMP's throughput. Throughput decreased to 166,900 b/d from 171,300 b/d a year ago. On April 19, 2005, TER announced that ES had completed its expansion thereby increasing capacity by 108,000 b/d to 280,000 b/d at a cost of about US$100 million, but earnings improvements are expected to be relatively modest because of ship-or-pay arrangements. They resemble, in essence, the fundamentals of gas-pipeline operations, making ES more or less unique.
- During Q1, TMP continued work on the TMX Project. It proposes a staged expansion of the existing Trans Mountain system (225,000 b/d capacity) between Edmonton, Alberta and Burnaby, B.C. The expansion consists of looping of the existing pipeline to existing facilities in Burnaby, B.C. and/or could include the extension of Trans Mountain through the B.C. Interior to a potential new VLCC capable port on the B.C. coast. On Jan. 31, 2005, Terasen Pipelines announced that it had received strong support from 17 different parties including existing and new customers who participated in the TMX Project's Expression of Interest process. TMP continues to develop the technical, regulatory and commercial components of the project and is working with potential shippers to attempt to finalize an interim commercial and tolling framework in Q2 prior to proceeding with an Open Season in summer 2005.
- **However, we view transhipments, if any, of petroleum from TER's marine terminal to Kitimat/Prince Rupert and, thence, to East Asia as costly and time-consuming.**

Water and Utility Services

- **Q1 2005 water and utility services earnings: $0.8 million vs. nil y/y.** Earnings from this segment which includes TER Waterworks, TER Utility Services, and TER's 30% interest in CustomerWorks LP, are typically stronger in the second and third quarters, and are weaker in first and fourth quarters reflecting seasonal patterns of new construction. Earnings increased y/y due to growth in the base waterworks and utility service businesses and a small contribution from the July 31, 2004 acquisition of a 50% interest in the Fairbanks Sewer and Water Inc. (FSW).
- TER still expects this business to deliver one-third of its annual growth objectives of 6%.

Other Activities

- **Other Activities** (including Terasen International, TER's 45% interest in Clean Energy (CE), and corporate interest and administration charges), **reduced its loss to $2.9 million in Q1 2005 vs. a loss of $5.1 million y/y.** The lower loss y/y was due to a reduction in corporate expenses, improved operations at CE, and a $2.6 million net after-tax mark-to-market gain from CE's outstanding gas positions.
- Operation and maintenance expenses declined to $3.9 million from $5.1 million due to cost reductions and operating efficiencies.

Financial and Outlook

- **Capital Expenditures** in Q1 2005 were $83.8 million vs. $28.9 million in Q1 2004, mostly on the $49.4 million acquisition of the Coastal Facilities buildings by Natural Gas Distribution. Projected 2005 capital expenditures are about $350 million.
- **Cash from Operations**: Q1 2005: $99.1 million vs. $105.2 million y/y.
- **TER's growth forecast is 6% using the 2004 EPS base of $1.40 (excluding Clean Energy mark-to-market gains).** TER expects to make up the Q1 shortfall in Petroleum Transportation earnings with better performances from all businesses throughout the balance of 2005.

Valuation

For the 12-month period ending March 2007, we are estimating EPS of $1.61; DPS of $1.04; retained EPS of $0.57; a retained EPS multiple of 10x; and a nominal long-term corporate bond yield of 6.75%, tax-effected to 5.40%. The support price is $19.26 and the residual price is $5.70, for a target price of $24.95 (rounded).

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SECONDARY STOCK RATING: Under Review – Our analyst has withdrawn the rating because of insufficient information and is awaiting more information and/or clarification; **Tender** – Our analyst is recommending that investors tender to a specific offering for the company's stock; **Restricted** – Because of ongoing investment banking transactions or because of other circumstances, NBF policy and/or laws or regulations preclude our analyst from rating a company's stock.

INDUSTRY RATING: NBF has an Industry Weighting system that reflects the view of our Economics & Strategy Group, using its sector rotation strategy. The three tiered system rates industries as **Overweight**, **Market Weight** and **Underweight**, depending on the sector's projected performance against broader market averages over the next 12 months.

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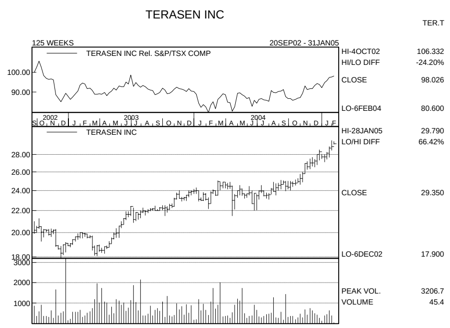
RBC Capital Markets

Research Comment

February 1, 2005



Fai Lee, CGA, CFA
(604) 257-7662
fai.lee@rbccm.com

Price:	$29.35	Price Target:	$32.00
52-Wk High:	$29.79	52-Wk Low:	$21.50
Float (MM):	104.9	Debt-to-Cap:	0.67
Shs O/S (MM):	114.1	Mkt Cap (MM):	$3,079
Dividend:	$0.84	Yield:	2.9%

Strategic Shareholders: Trans Mountain - 8.1%

(FY Dec 31)	2003A	2004E	2005E	2006E
EPS				
Basic	$1.37	$1.41	$1.54	$1.57
Diluted	$1.36	$1.40	$1.53	$1.56
P/E	21.4	20.8	19.1	18.7
EPS	Q1	Q2	Q3	Q4
2003A	$0.71	$0.12	($0.08)	$0.62
2004E	$0.76A	$0.10A	($0.03)A	$0.59
2005E	$0.78	$0.14	($0.03)	$0.65

All values in C$ unless otherwise noted.

EPS are normalized for unusual and non-recurring items and may not be consistent with GAAP.

For Required Disclosures, please see page 4.

Maureen Howe, a member of the Canadian pipelines and utilities team, is an associate of an insider of Terasen Inc., a component of the pipelines and utilities sector.

Terasen Inc.

(TSX: TER)

Outperform

Average Risk

“Moving Full Steam Ahead” With TMX Project

Event

Given strong support from its customers, Terasen plans to proceed to the next phase of the Trans Mountain system expansion project (“TMX Project”).

Investment Opinion

- **Expression of Interest process confirms support.** Through a non-binding Expression of Interest process, Terasen’s customers have indicated a strong need for additional crude oil pipeline capacity from Alberta to the west coast of B.C. by 2008. Based on the customer support, Terasen plans to move ahead with the initial expansion phase, TMx1. The next step is to finalize a tolling framework with customers leading to a formal open season expected this summer. Whether the tolling framework for TMx1 will be included as part of the discussions on the renewal of Trans Mountain’s Incentive Toll Settlement (ITS) still needs to be determined.
- **Future expansion plans past 2008 still uncertain.** While customers also indicated the need for significant expansion of the Trans Mountain system beyond 2008, there is no clear consensus on whether the future expansion should involve the Southern Option (i.e., further expansion of the existing Trans Mountain System to the Lower Mainland of B.C.) or the Northern Option (i.e. greenfield pipeline to a deepwater port at Prince Rupert or Kitimat). The lack of consensus is not surprising given the various issues that must be considered as discussed in our *Moving Oil Sands Product to Market* report dated December 22, 2004.
- **Implications.** Overall, we view yesterday’s announcement as a positive development for Terasen and the TMX Project. We believe there is a reasonable probability that Terasen will eventually proceed to the construction phase of TMx1. It is difficult to evaluate the financial impact to Terasen without additional information on the final tolling arrangement for TMx1 and the outcome of the renewal of Trans Mountain’s ITS, which expires at the end of 2005. We believe that Terasen will look to address the two issues at the same time. Nevertheless, we have attempted to estimate the EPS impact for TMx1 on a standalone basis assuming a cost of service methodology. Based on our assumptions, we estimate a full-year EPS impact of approximately $0.07 in 2009.
- **Valuation.** Our target price of $32.00 (unchanged) reflects a 12-month dividend distribution one-year forward of $0.95 and a required dividend yield of 2.95%. Terasen is ranked Outperform, Average Risk.

Details

Yesterday, Terasen announced that it has received strong support from 17 different parties including existing and new customers to proceed to the next phase of the Trans Mountain system expansion project ("TMX"). The TMX Project is designed to meet increased demand for pipeline capacity to the west coast of British Columbia due to growing Alberta oil sands production. While it has not provided information on the specific customers that support the projects or the volumes that they are interested in transporting, Terasen indicated that it has received support from Canadian producers, West Coast refiners and Far East interests.

In December 2004, Terasen commenced a non-binding Expression of Interest process to confirm the level of support from potential customers for the TMX Project and its various phases. Through this process, customers have indicated a strong need for additional pipeline capacity from Alberta to the west coast of B.C. by 2008. Based on the customer support, Terasen plans to move ahead with the initial expansion phase, TMx1. The next step is to finalize a tolling framework with customers, leading to a formal open season expected this summer. Whether the tolling framework for TMx1 will be included as part of the discussions on the renewal of Trans Mountain's Incentive Toll Settlement (ITS) still needs to be determined.

Pending final commercial arrangements and regulatory approvals, TMx1 would increase Trans Mountain's capacity from 225,000 bpd to 300,000 bpd by the end of 2008. TMx1 would be constructed in two phases. The first phase would add 35,000 bpd of capacity by the end of 2006 through the addition of pump stations along the pipeline system at an estimated cost of $205 million. The second phase would involve looping 178 kilometres of the system, providing an additional 40,000 bpd by the end of 2008 at an estimated cost of $365 million.

While customers also indicated the need for significant expansion of the Trans Mountain system beyond 2008, there is no clear consensus on whether the future expansion should involve the Southern Option (i.e., further expansion of the existing Trans Mountain System to the Lower Mainland of B.C.) or the Northern Option (i.e. greenfield pipeline to a deepwater port at Prince Rupert or Kitimat). The lack of consensus is not surprising given the various issues that must be considered as discussed in our *Moving Oil Sands Product to Market* report dated December 22, 2004.

Exhibit 1: TMX Project

Source: Company reports

Implications

Overall, we view yesterday’s announcement as a positive development for Terasen and the TMX Project. We believe there is a reasonable probability that Terasen will eventually proceed to the construction phase of TMx1.

It is difficult to evaluate the financial impact to Terasen without additional information on the final tolling arrangement for TMx1 and the outcome of the renewal of Trans Mountain’s ITS, which expires at the end of 2005. We believe that Terasen will attempt to address the two issues at the same time. Trans Mountain has performed well under its ITS over the last four years and faces the risk that its earnings could decline under a renewed agreement. While the ultimate impact could be more significant, we have reflected a $3 million decline in Trans Mountain’s earnings in 2006 compared to 2005 pending additional information on the status of the ITS renewal negotiations that we hope will be forthcoming over the coming months. Depending on the outcome of Terasen’s negotiations, the development of TMx1 could mitigate part or all of the potential negative impact associated with the ITS renewal.

While we believe that the TMx1 tolling arrangement and Trans Mountain’s ITS renewal agreement could be linked, we have attempted to estimate the EPS impact for TMx1 on a standalone basis assuming a cost of service methodology. In our analysis, we have assumed a deemed common equity component of 35%, an allowed ROE of 10%, an equity issuance of 6.2 million shares at $32.00 to finance Terasen’s equity investment, and assumed EPS growth of 6% between 2006 and 2009. Based on our assumptions, we estimate a full-year EPS impact of approximately $0.07 in 2009.

Exhibit 2: 2009E EPS Impact

	2009E
TMx 1 Phase 1	$205.0
TMx 1 Phase 2	365.0
Total	$570.0
Deemed common equity	35.0%
Deemed common equity	$199.5
Allowed ROE	10.0%
Allowed earnings	$20.0
Shares outstanding before TMx1	104.9
Additional shares from TMx1	6.2
Total shares (MM)	111.1
EPS impact before dilution	$0.18
Dilution based on assumed 6% annual EPS growth	($0.10)
Potential EPS Impact	$0.07

Source: RBC Capital Markets estimates

Valuation

Our valuation for Terasen is largely based on a dividend yield approach. When the current yield of the ten-year Government of Canada benchmark bond is below 6%, we believe that a dividend yield approach is an appropriate valuation method for Terasen. Our target price of $32.00 reflects a 12-month dividend distribution one-year forward of $0.95 and a required dividend yield of 2.95%.

Price Target Impediments

Factors that could have negative implications for Terasen’s earnings and our target price include unexpected increases in operating costs that are unrecoverable under its incentive agreements, failure to renew Trans Mountain’s Incentive Toll Settlement after the end of 2005 and a significant and prolonged decline in Western Canadian petroleum production.

Company Description

Terasen is engaged in the transmission and distribution of natural gas and the transportation of crude oil and refined products.

Required Disclosures

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Outperform (O): Expected to materially outperform sector average over 12 months.
Sector Perform (SP): Returns expected to be in line with sector average over 12 months.
Underperform (U): Returns expected to be materially below sector average over 12 months.

Risk Qualifiers (any of the following criteria may be present):
Average Risk (Avg): Volatility and risk expected to be comparable to sector; average revenue and earnings predictability; no significant cash flow/financing concerns over coming 12-24 months; fairly liquid.
Above Average Risk (AA): Volatility and risk expected to be above sector; below average revenue and earnings predictability; may not be suitable for a significant class of individual equity investors; may have negative cash flow; low market cap or float.
Speculative (Spec): Risk consistent with venture capital; low public float; potential balance sheet concerns; risk of being delisted.

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Rating	Count	Percent	Count	Percent
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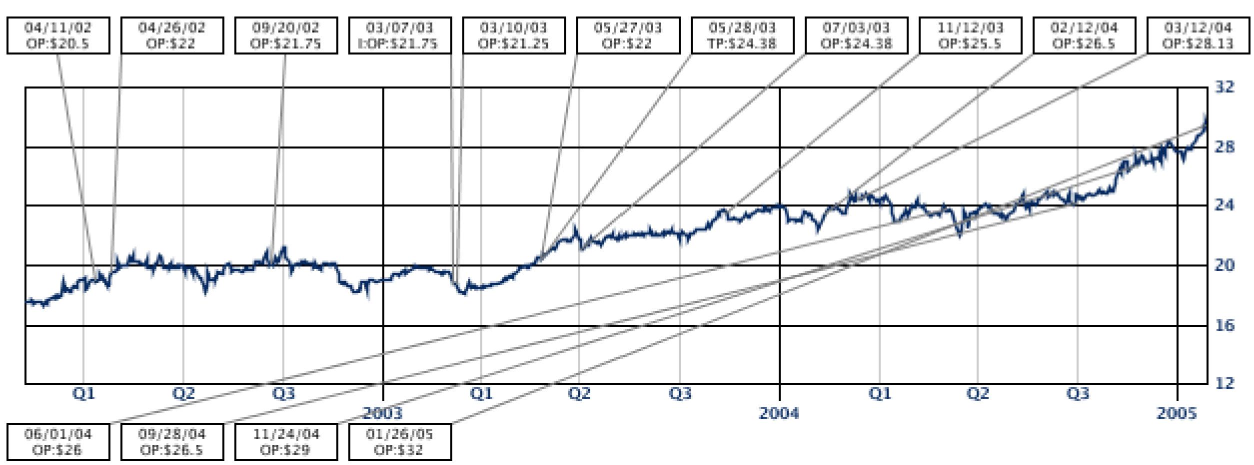
HOLD [SP]	388	43.79	105	27.06
SELL [U]	86	9.71	14	16.28

Rating and Price Target History for: Terasen Inc. as of 01-28-2005



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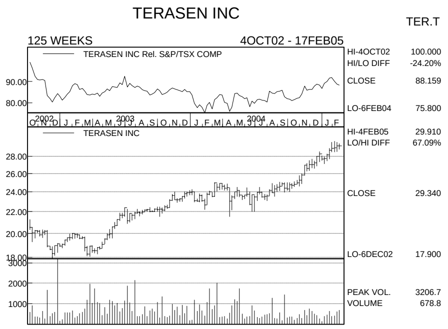

Terasen Inc.

(TSX: TER)

Outperform

Average Risk

2004 Results In Line With Expectations; Annual Dividend Increased by $0.06 to $0.90

Fai Lee, CGA, CFA
(604) 257-7662
fai.lee@rbccm.com

Price:	$29.34	Price Target:	$32.00
52-Wk High:	$29.91	52-Wk Low:	$21.50
Float (MM):	105.2	Debt-to-Cap:	0.65
Shs O/S (MM):	114.4	Mkt Cap (MM):	$3,086
Dividend:	$0.90	Yield:	3.1%

Strategic Shareholders: Trans Mountain - 8.0%

(FY Dec 31)	2003A	2004A	2005E	2006E
EPS				
Old Basic	$1.37	$1.40	$1.54	$1.57
Old Diluted	$1.36	$1.39	$1.53	$1.56
Basic	$1.37	$1.40	$1.50	$1.57
Diluted	$1.36	$1.39	$1.49	$1.56
P/E	21.4	21.0	19.6	18.7
EPS	Q1	Q2	Q3	Q4
2003A	$0.62	$0.18	$0.03	$0.54
2004A	$0.63	$0.17	$0.08	$0.52
2005E	$0.63	$0.21	$0.10	$0.56

All values in C$ unless otherwise noted.

EPS are normalized for unusual and non-recurring items and may not be consistent with GAAP.

For Required Disclosures, please see page 4.

Maureen Howe, a member of the Canadian pipelines and utilities team, is an associate of an insider of Terasen Inc., a component of the pipelines and utilities sector.

Event

Terasen announced its 2004 financial results and increased its annual dividend.

Investment Opinion

- **2004 results in line with expectations.** Terasen's normalized EPS was $1.40 in 2004 compared to our estimate of $1.41 and $1.37 in 2003. Lower-than-expected results from Natural Gas Distribution and Other Activities were largely offset by higher-than-expected Petroleum Transportation results.
- **Annual dividend increased by 7.1% from $0.84 to $0.90.** The increase was in line with our expectations, but the timing was earlier than expected. In previous years, Terasen increased its common dividend in the second quarter. According to Terasen, the decision to increase the dividend in the first quarter reflects strong results, a positive outlook for 2005 and aligns the dividend increase with the company's fiscal year.
- **2005 EPS estimate decreased to reflect lower throughput volumes.** For 2005, Terasen's management is targeting EPS growth of 6% from a base of $1.40. EPS growth is expected to be driven by incremental earnings from Trans Mountain and the Express System expansion, operating efficiencies and customer growth in the Natural Gas Distribution business, and continued growth in the water and utility services business. During the first few months of 2005, management expects temporary weakness in throughput volumes on the Trans Mountain system primarily due to production outages in the Alberta oil sands and west coast refinery turnarounds. Largely reflecting weaker throughput volumes on the Trans Mountain system, we have reduced our 2005 EPS estimate from $1.54 to $1.50.
- **Growth outlook remains positive.** Notwithstanding the potential risk to earnings associated with a new Incentive Tolling Settlement at Trans Mountain and the temporary decline in throughput volumes expected on the Trans Mountain System in the first few months of 2005, we believe that the overall growth outlook for Terasen remains positive given the number of potential opportunities that are available to the company.
- **Valuation.** Our target price of $32.00 (unchanged) reflects a 12-month dividend distribution one-year forward of $0.96 and a required dividend yield of 2.95%. Terasen is ranked Outperform, Average Risk.

Details

Overall, the 2004 results were in line with our expectations. Terasen's normalized EPS was $1.40 in 2004 compared to our estimate of $1.41 and $1.37 in 2003. Lower-than-expected results from Natural Gas Distribution and Other Activities were largely offset by higher-than-expected Petroleum Transportation results. Terasen's 2004 financial results are summarized in Exhibit 1.

Exhibit 1: 2004 Financial Results Summary ($MM Except EPS or Otherwise Indicated)

	For 3 mos. ended Dec. 31		For 12 mos. ended Dec. 31		
	2004	2003	2004	2003	Comments
Natural gas distribution					
Terasen Gas	$36.2	$37.5	$69.7	$72.6	Results prior to Q4/04 restated to reflect change in accounting for income tax expense.
Terasen Gas (Vancouver Island)	6.4	7.3	26.2	26.2	
	42.6	44.8	95.9	98.8	$2.7 million lower-than-expected.
Petroleum transportation					
Trans Mountain	11.2	10.0	39.4	36.8	
Corridor	3.8	4.0	15.6	10.7	
Express System	4.9	3.9	15.9	13.3	
	19.9	17.9	70.9	60.8	$2.4 million higher-than-expected.
Water and utility services	0.7	0.4	6.6	4.1	
Other activities	(8.3)	(7.0)	(26.9)	(21.2)	$1.0 million lower than expected.
Normalized earnings	$54.9	$56.1	$146.5	$142.5	
Restructuring charge		(3.4)		(3.4)	Terasen Gas
Westport Innovations writedown		(1.8)		(1.8)	Other activities
Impact of forest fires in Q3/03				(1.0)	Trans Mountain
Foreign exchange loss at Express				(3.6)	Express System
Mark-to-market gains (losses) at Clean Energy	(1.0)		3.3		Other activities
Reported earnings	$53.9	$50.9	$149.8	$132.7	
Weighted average shares outstanding (MM)	105.0	104.1	104.7	103.8	
Normalized EPS	$0.52	$0.54	$1.40	$1.37	

Source: Terasen; RBC Capital Markets

Natural Gas Distribution

Normalized earnings from Natural Gas Distribution were $95.9 million in 2004 compared to $98.8 million in 2003. The decline was attributed to a reduction in the allowed returns on equity at Terasen Gas (Vancouver Island) ("TGVI") and Terasen Gas (-$2.4 million) and the introduction of an earnings sharing mechanism for operating efficiencies (-$4.7 million), partially offset by operating efficiencies achieved through the integration of the Terasen Gas and TGVI operations (+$4.1 million).

In Q4/04, the accounting for income tax expense at Terasen Gas was changed. Under the new accounting methodology, income tax expense is determined by applying the effective annual tax rate to pre-tax income in the quarter. Previously, Terasen Gas allocated annual income tax expense was based on budgeted sales revenue for the four quarters. Reflecting the change in accounting, Terasen Gas' quarterly results prior to Q4/04 were restated. According to Terasen, the change in accounting had no impact on annual financial results. However, it should be noted that recurring earnings from Natural Gas Distribution declined by $0.7 million during the first nine months of 2004 instead of increasing by $1 million as previously reported by Terasen. Based on the previously reported results and our forecast for a modest decline in Q4/04 earnings at Terasen Gas and TGVI, we had expected a relatively flat contribution from Natural Gas Distribution in 2004 compared to 2003.

Petroleum Transportation

Normalized earnings from Petroleum Transportation were $70.9 million in 2004 compared to earnings of $60.8 million in 2003. Notwithstanding slightly lower-than-expected throughput volumes on the Trans Mountain Canadian mainline, earnings from Petroleum Transportation were higher-than-expected due to operating efficiencies at Trans Mountain and increased earnings from the Express System.

Water and Utility Services

Normalized earnings from Water and Utility Services increased from $4.1 million in 2003 to $6.6 million in 2004. The increase reflected growth in existing operations, as well as contributions from acquisitions including Fairbanks Sewer & Water Inc. The Fairbanks acquisition was completed on July 31, 2004.

Other Activities

Excluding a $3.3 million after-tax mark-to-market gain for natural gas derivative positions at Clean Energy, earnings from Other Activities decreased from ($21.2) million to ($26.9) million. The decrease largely reflects higher income tax expense in 2004.

Dividend Increase

Yesterday, Terasen's Board of Directors approved a 7.1% increase to the annual dividend from $0.84 to $0.90. The increase was in line with our expectations, but the timing was earlier than expected. In previous years, Terasen increased its common dividend in the second quarter. According to Terasen, the decision to increase the dividend in the first quarter reflects strong results, a positive outlook for 2005 and aligns the dividend increase with the company's fiscal year.

EPS Estimates / Management Guidance

For 2005, Terasen's management is targeting EPS growth of 6% from a base of $1.40. EPS growth is expected to be driven by incremental earnings from Trans Mountain and the Express System expansion, operating efficiencies and customer growth in the Natural Gas Distribution business, and continued growth in the water and utility services business. During the first few months of 2005, management expects temporary weakness in throughput volumes on the Trans Mountain system primarily due to production outages in the Alberta oil sands and west coast refinery turnarounds.

Largely reflecting weaker throughput volumes on the Trans Mountain system, we have reduced our 2005 EPS estimate from $1.54 to $1.50. The outlook for 2006 will depend on the outcome of Trans Mountain's negotiations with its shippers with respect to a new Incentive Toll Settlement (ITS). Management expects to reach a satisfactory agreement on a new ITS and remains committed to delivering on its target of 6% annual EPS growth. Pending additional information on the new ITS, we are maintaining our 2006 EPS estimate of $1.57 at this time.

Outlook

ITS

Trans Mountain has initiated discussions with its shippers regarding the commercial terms for a new ITS, which would replace the current ITS that is set to expire at the end of 2005. Depending on the final tolling arrangement with shippers, Trans Mountain's earnings could be materially negatively impacted in 2006. However, as previously stated, management expects to reach a satisfactory agreement on a new ITS.

TMX

Terasen is working with shippers on finalizing the commercial and tolling framework for its TMX project prior to holding an open season for binding commitments by mid-2005. The company expects to spend an additional $7 to $12 million prior to receiving binding support for the project. At this time, negotiations for the tolling framework for the TMX project and discussions for a new ITS are being conducted separately. However, an umbrella tolling agreement with shippers is not out of the question in the future.

If Terasen proceeds with the first phase of the project (TMx1), it expects to recognize an allowance for funds used during construction (AFUDC) during the construction period. Booking AFUDC could mitigate the potential negative earnings impact associated with a new ITS. TMx1 would be constructed in two phases. The first phase would add 35,000 bpd of capacity by the end of 2006 through the addition of pump stations along the pipeline system at an estimated cost of $205 million. The second phase would involve looping 178 kilometres of the system, providing an additional 40,000 bpd by the end of 2008 at an estimated cost of $365 million.

2005 Capital Expenditures Program

Terasen is forecasting $350 million of capital expenditures in 2005 compared to $154.4 million in 2004. Major capital expenditures in 2005 include the unwinding of a synthetic lease that was previously entered into by Terasen Gas to finance new building facilities in the Greater Vancouver area ($50 million), the purchase and upgrade of the Texada Island compressor station ($15 milllion), initial expenditures for TGVI's proposed LNG storage facility ($23 million), further development of Trans Mountain's TMX Project ($13.5 million) and Corridor Pipeline de-bottlenecking ($6.5 million). The 2005 capital expenditures budget also includes minor acquisitions at the water and utility services business. Terasen expects to finance the planned capital expenditures with internally generated funds and debt.

Vancouver Island Capacity Expansion

On February 16, the British Columbia Utilities Commission (BCUC) approved TGVI's proposal to build a $100 million LNG storage facility near Nanaimo, subject to several conditions, including the execution of a long-term Transportation Service Agreement (TSA) with BC Hydro substantially in the form indicated as acceptable by the BCUC. Yesterday, the BCUC approved BC Hydro's agreement to purchase electricity from Duke Point Power Limited Partnership's proposed power plant, subject to BC Hydro entering into a long-term TSA with TGVI to serve the proposed power plant. In reaction to the BCUC decision, the Joint Industry Electricity Steering Committee announced plans to appeal the regulator's ruling to the appropriate court in the next several days. TGVI plans to work with BC Hydro on a TSA, but there is no certainty that a TSA will ultimately be executed as highlighted by the expected legal action.

Corridor Expansion

Terasen has been working with Shell and its partners on the potential expansion of the Corridor Pipeline from 155,000 bpd to 300,000 bpd. Expansion of the system is expected to be undertaken in phases. The first phase, which has been approved by the shippers, involves de-bottlenecking the existing system by adding pumping capacity. The initial phase is expected to add 35,000 bpd of capacity by the fall of 2005 at an estimated cost of $6.5 million. The second phase would increase system capacity by 110,000 bpd at an estimated cost of $500-$600 million. This phase is under review and, if approved, is expected to be in service by 2009.

Summary

Notwithstanding the potential risk to earnings associated with a new Incentive Tolling Settlement at Trans Mountain and the temporary decline in throughput volumes expected on the Trans Mountain System in the first few months of 2005, we believe that the overall growth outlook for Terasen remains positive given the number of potential opportunities that are available to the company. Key events to watch for in 2005 include the outcome of the discussions on a new ITS and the TMX project.

Valuation

Our valuation for Terasen is largely based on a dividend yield approach. When the current yield of the ten-year Government of Canada benchmark bond is below 6%, we believe that a dividend yield approach is an appropriate valuation method for Terasen. Our target price of $32.00 reflects a 12-month dividend distribution one-year forward of $0.96 and a required dividend yield of 2.95%.

Price Target Impediments

Factors that could have negative implications for Terasen’s earnings and our target price include unexpected increases in operating costs that are unrecoverable under its incentive agreements, failure to renew Trans Mountain’s Incentive Toll Settlement after the end of 2005 and a significant and prolonged decline in Western Canadian petroleum production.

Company Description

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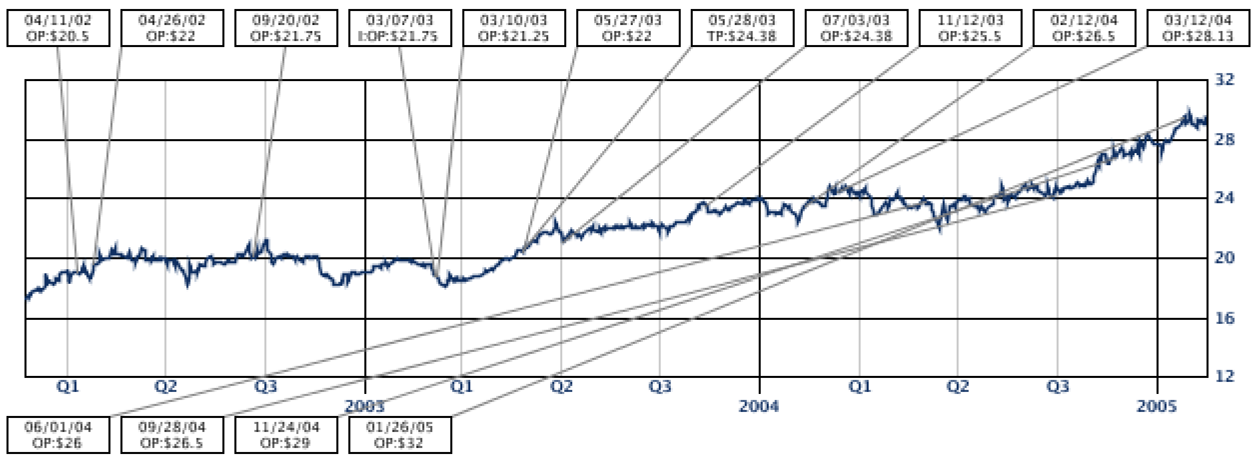
BUY [TP/O]	416	46.64	150	36.06
HOLD [SP]	399	44.73	107	26.82
SELL [U]	77	8.63	14	18.18

Rating and Price Target History for: Terasen Inc. as of 02-17-2005



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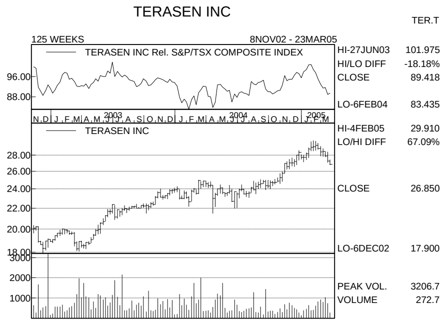
RBC Capital Markets

Research Comment

March 24, 2005



Terasen Inc.

(TSX: TER)

Outperform

Average Risk

2005 EPS Estimate Reduced to Reflect Lower Throughput at Trans Mountain in Q1/05

Fai Lee, CGA, CFA
(604) 257-7662
fai.lee@rbccm.com

Price:	$26.85	Price Target:	$32.00
52-Wk High:	$29.91	52-Wk Low:	$21.50
Float (MM):	105.2	Debt-to-Cap:	0.65
Shs O/S (MM):	114.4	Mkt Cap (MM):	$2,824
Dividend:	$0.90	Yield:	3.4%

Strategic Shareholders: Trans Mountain - 8.0%

(FY Dec 31)	2003A	2004A	2005E	2006E
EPS				
Old Basic	$1.37	$1.40	$1.50	$1.57
Old Diluted	$1.36	$1.39	$1.49	$1.56
Basic	$1.37	$1.40	$1.48	$1.57
Diluted	$1.36	$1.39	$1.47	$1.56
P/E	19.6	19.2	18.1	17.1
EPS	Q1	Q2	Q3	Q4
2003A	$0.62	$0.18	$0.03	$0.54
2004A	$0.63	$0.17	$0.08	$0.52
2005E	$0.61	$0.21	$0.10	$0.57

All values in C$ unless otherwise noted.

EPS are normalized for unusual and non-recurring items and may not be consistent with GAAP.

Event

We have reduced our 2005 EPS estimate to reflect lower forecast earnings from Trans Mountain in Q1/05.

Investment Opinion

- **Throughput in Q1/05 expected to be lower than originally forecast.** Due to production outages in the Alberta oil sands and west coast refinery turnarounds, we had reflected a decline in throughput on the Trans Mountain Canadian mainline in Q1/05. Based on a recent presentation by Terasen to the National Energy Board, we believe that we have underestimated the extent of the decline.
- **Expect throughput volumes to rebound.** Trans Mountain has throughput protection if annual volumes on the Canadian mainline decline below 179,265 bpd. However, we believe the decline in Q1/05 is due to temporary factors and we do not expect annual volumes to decline below 179,265 bpd. Supporting our view, April nominations for the Trans Mountain Canadian mainline have been fairly strong and the pipeline is back in apportionment.
- **2005 EPS estimate decreased to reflect lower throughput volumes.** Reflecting weaker-than-forecast throughput volumes on the Trans Mountain system in Q1/05, we have reduced our 2005 EPS estimate from $1.50 to $1.48.
- **Valuation.** Our target price of $32.00 reflects a 12-month dividend distribution one-year forward of $0.96 and a required dividend yield of 2.95%.

For Required Disclosures, please see page 2.

Maureen Howe, a member of the Canadian pipelines and utilities team, is an associate of an insider of Terasen Inc., a component of the pipelines and utilities sector.

Details

Terasen's management indicated during its fourth quarter conference call that it expected temporary weakness in throughput volumes on the Trans Mountain system during the first few months of 2005, primarily due to production outages in the Alberta oil sands and west coast refinery turnarounds. In our financial model, we had reflected a decline in throughput on the Trans Mountain Canadian mainline from 239,100 bpd in Q4/04 to 200,000 bpd in Q1/05. Based on a recent presentation by Terasen to the National Energy Board, we believe Trans Mountain Canadian mainline throughput will fall below our previous estimate. It appears that throughput in January and February was about 170,000 bpd and the forecast for March is about 190,000 bpd.

Trans Mountain has throughput protection if annual volumes on the Canadian mainline decline below 179,265 bpd. However, we believe the decline in Q1/05 is due to temporary factors and we do not expect annual volumes to decline below 179,265 bpd. According to Terasen, April nominations for the Trans Mountain Canadian mainline have been fairly strong and the pipeline is back in apportionment.

Reflecting weaker-than-forecast throughput volumes on the Trans Mountain system in Q1/05, we have reduced our 2005 EPS estimate from $1.50 to $1.48.

Valuation

Our valuation for Terasen is largely based on a dividend yield approach. When the current yield of the ten-year Government of Canada benchmark bond is below 6%, we believe that a dividend yield approach is an appropriate valuation method for Terasen. Our target price of $32.00 reflects a 12-month dividend distribution one-year forward of $0.96 and a required dividend yield of 2.95%.

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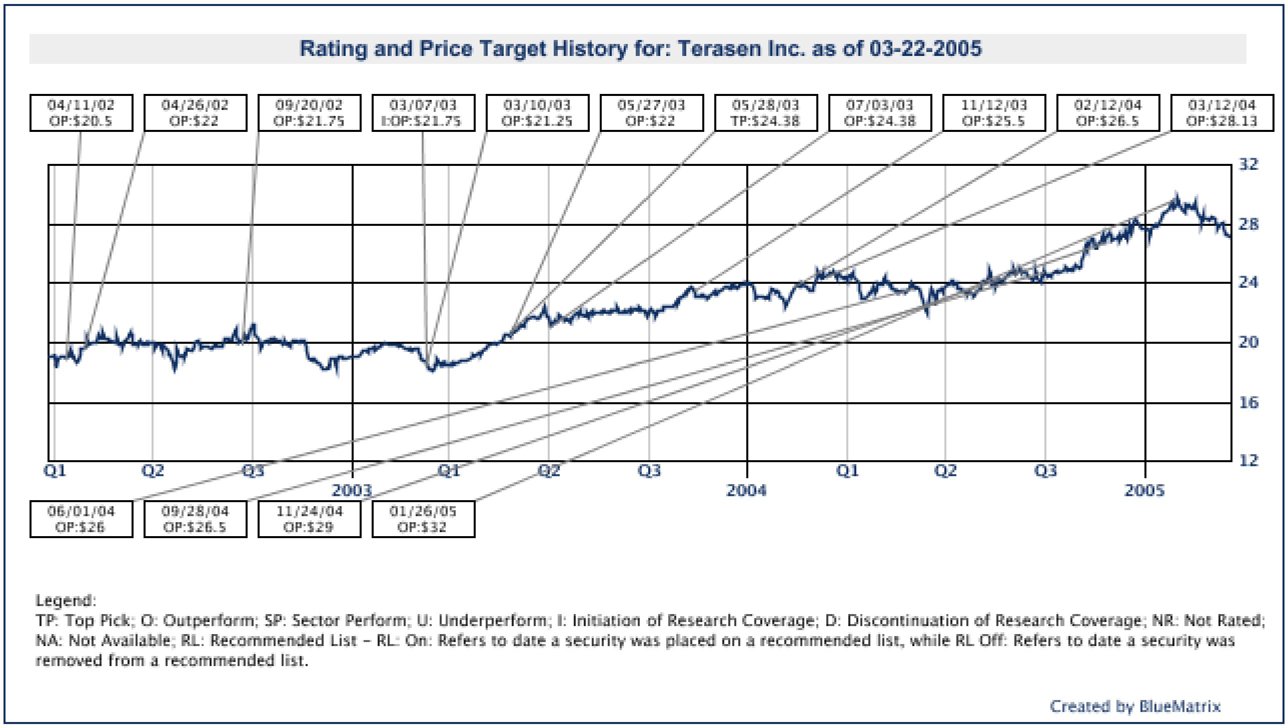
HOLD [SP]	398	44.37	105	26.38
SELL [U]	78	8.70	15	19.23



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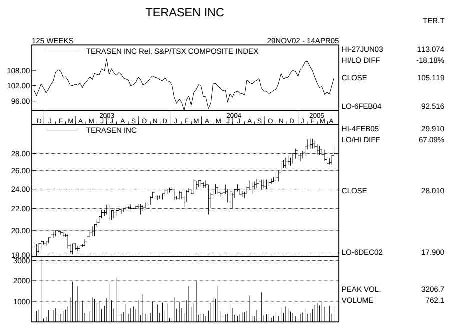
Research Comment

April 15, 2005



Fai Lee, CGA, CFA
(604) 257-7662
fai.lee@rbccm.com

Price:	$28.01	Price Target:	$32.00
52-Wk High:	$29.91	52-Wk Low:	$21.50
Float (MM):	105.2	Debt-to-Cap:	0.65
Shs O/S (MM):	114.4	Mkt Cap (MM):	$2,946
Dividend:	$0.90	Yield:	3.2%

Strategic Shareholders: Trans Mountain - 8.0%

(FY Dec 31)	2003A	2004A	2005E	2006E
EPS				
Basic	$1.37	$1.40	$1.48	$1.57
Diluted	$1.36	$1.39	$1.47	$1.56
P/E	20.4	20.0	18.9	17.8
EPS	Q1	Q2	Q3	Q4
2003A	$0.62	$0.18	$0.03	$0.54
2004A	$0.63	$0.17	$0.08	$0.52
2005E	$0.61	$0.21	$0.10	$0.57

All values in C$ unless otherwise noted.

EPS are normalized for unusual and non-recurring items and may not be consistent with GAAP.

For Required Disclosures, please see page 2.

Maureen Howe, a member of the Canadian pipelines and utilities team, is an associate of an insider of Terasen Inc., a component of the pipelines and utilities sector.

Terasen Inc.

(TSX: TER)

Outperform

Average Risk

Enbridge Signs MOU with PetroChina; We Remain Positive on Terasen's TMx1 Project

Event

Enbridge announced a memorandum of understanding (MOU) with PetroChina International Company Limited.

Investment Opinion

- **MOU with PetroChina.** Under the MOU, Enbridge and PetroChina have agreed to cooperate on the development of the Gateway Pipeline and supply of crude oil from Canada to China. The Gateway Pipeline is a proposed 400,000 bpd pipeline project designed to transport Alberta oil sands production from Edmonton, Alberta to a port on the west coast of British Columbia. The Gateway project can be considered as a rival project to the northern option of Terasen's TMX Project.
- **We don't view the MOU as a major obstacle for the TMX Project.** Enbridge's management indicated that the MOU is a preliminary step in the development of the Gateway Project and it cautioned against reading too much into the announcement. At this time, we believe that there is insufficient information to accurately determine the implications, if any, of Enbridge's MOU on Terasen's TMX Project. For example, we do not know the terms of PetroChina's involvement/commitment in the Gateway project, whether PetroChina has agreed to deal exclusively with Enbridge or if there are any sunset clauses to the MOU.
- **Still remain positive about development of TMx1**. Notwithstanding Enbridge's announcement, we remain positive with respect to the development of the first phase of Terasen's TMX project ("TMx1") based on the results of its previously announced Expression of Interest process and discussions with Terasen's management.
- **Valuation.** Our target price of $32.00 (unchanged) reflects a 12-month dividend distribution one-year forward of $0.96 and a required dividend yield of 2.95%.

Details

Yesterday, Enbridge announced that it has entered into a memorandum of understanding with PetroChina International Company Limited to cooperate on the development of the Gateway Pipeline and supply of crude oil from Canada to China. PetroChina is a large integrated company that is involved in the exploration, development and production of crude oil and natural gas; refining, transportation, storage and marketing, including import and export, of crude oil and petroleum products; production and sale of chemical products; and transmission, marketing and sale of natural gas.

Under the MOU, Enbridge will assist PetroChina to aggregate long-term supplies of Canadian crude oil with a target of approximately 200,000 bpd. Enbridge is seeking commitments from other potential shippers on the Gateway Pipeline to fill the remaining capacity.

Enbridge's management indicated that the MOU is a preliminary step in the development of the Gateway Project and it cautioned against reading too much into the announcement stating, "…there remains a great deal to be accomplished before the Gateway Pipeline can become a reality." At this time, we believe that there is insufficient information to accurately determine the implications, if any, of Enbridge's MOU on Terasen's TMX Project. For example, we do not know the terms of PetroChina's involvement/commitment in the Gateway project, whether PetroChina has agreed to deal exclusively with Enbridge or if there are any sunset clauses to the MOU. Notwithstanding Enbridge's announcement, we remain positive with respect to the development of the first phase of Terasen's TMX project ("TMx1") based on the results of its previously announced Expression of Interest process and discussions with Terasen's management.

Valuation

Our valuation for Terasen is largely based on a dividend yield approach. When the current yield of the ten-year Government of Canada benchmark bond is below 6%, we believe that a dividend yield approach is an appropriate valuation method for Terasen. Our target price of $32.00 reflects a 12-month dividend distribution one-year forward of $0.96 and a required dividend yield of 2.95%.

Price Target Impediments

Factors that could have negative implications for Terasen's earnings and our target price include unexpected increases in operating costs that are unrecoverable under its incentive agreements, failure to renew Trans Mountain's Incentive Toll Settlement after the end of 2005 and a significant and prolonged decline in Western Canadian petroleum production.

Company Description

Terasen is engaged in the transmission and distribution of natural gas and the transportation of crude oil and refined products.

Required Disclosures

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Ratings
Top Pick (TP): Represents best in Outperform category; analyst's best ideas; expected to significantly outperform the sector over 12 months; provides best risk-reward ratio; approximately 10% of analyst's recommendations.
Outperform (O): Expected to materially outperform sector average over 12 months.
Sector Perform (SP): Returns expected to be in line with sector average over 12 months.
Underperform (U): Returns expected to be materially below sector average over 12 months.
Risk Qualifiers (any of the following criteria may be present):
Average Risk (Avg): Volatility and risk expected to be comparable to sector; average revenue and earnings predictability; no significant cash flow/financing concerns over coming 12-24 months; fairly liquid.
Above Average Risk (AA): Volatility and risk expected to be above sector; below average revenue and earnings predictability; may not be suitable for a significant class of individual equity investors; may have negative cash flow; low market cap or float.
Speculative (Spec): Risk consistent with venture capital; low public float; potential balance sheet concerns; risk of being delisted.

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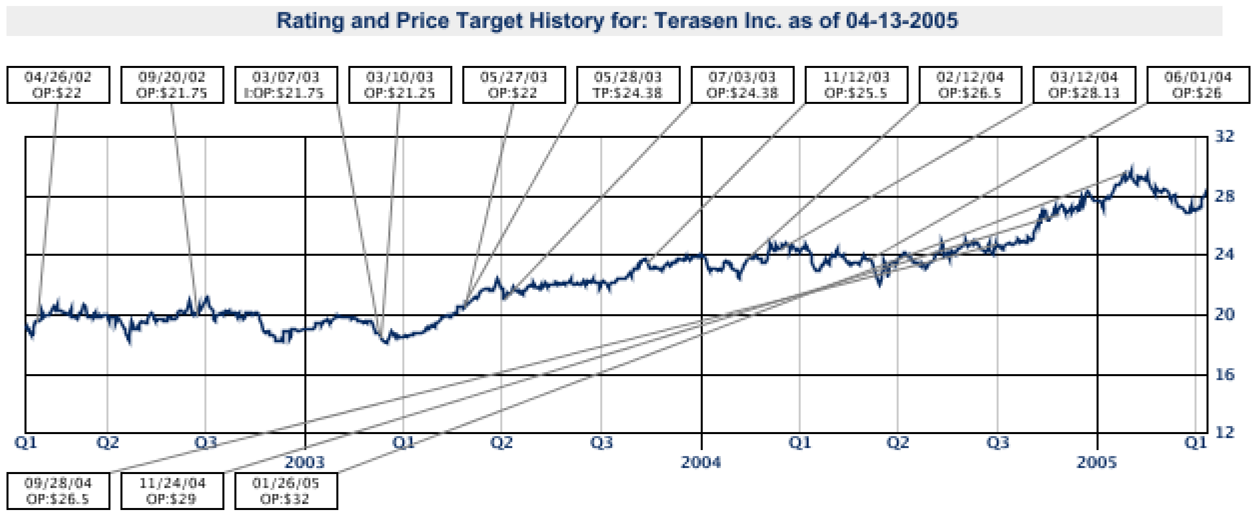
Distribution of Ratings, Firmwide

	RBC Capital Markets		Investment Banking Serv./Past 12 Mos.	
Rating	Count	Percent	Count	Percent
BUY [TP/O]	383	41.59	126	32.90
HOLD [SP]	444	48.21	134	30.18
SELL [U]	94	10.21	25	26.60



Legend:
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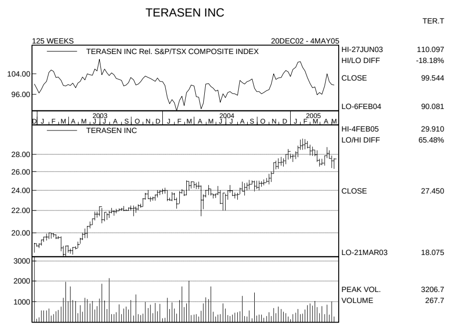
RBC Capital Markets

Research Comment

May 5, 2005



Terasen Inc.

(TSX: TER)

Outperform

Average Risk

Q1/05 Results In Line With Expectations; On Track for 2005

Fai Lee, CGA, CFA
(604) 257-7662
fai.lee@rbccm.com

Price:	$27.45	Price Target:	$32.00
52-Wk High:	$29.91	52-Wk Low:	$22.00
Float (MM):	105.4	Debt-to-Cap:	0.68
Shs O/S (MM):	114.6	Mkt Cap (MM):	$2,894
Dividend:	$0.90	Yield:	3.3%

Strategic Shareholders: Trans Mountain - 8.0%

(FY Dec 31)	2003A	2004A	2005E	2006E
EPS				
Basic	$1.37	$1.40	$1.48	$1.57
Diluted	$1.36	$1.39	$1.47	$1.56
P/E	20.0	19.6	18.5	17.5
EPS	Q1	Q2	Q3	Q4
2003A	$0.62	$0.18	$0.03	$0.54
2004A	$0.63	$0.17	$0.08	$0.52
2005E	$0.60A	$0.22	$0.12	$0.54

All values in C$ unless otherwise noted.

EPS are normalized for unusual and non-recurring items and may not be consistent with GAAP.

For Required Disclosures, please see page 4.

Maureen Howe, a member of the Canadian pipelines and utilities team, is an associate of an insider of Terasen Inc., a component of the pipelines and utilities sector.

Event

Terasen announced its first quarter results.

Investment Opinion

- **Q1/05 results in line with expectations.** Terasen's normalized EPS were $0.60 in Q1/05 compared to our estimate of $0.61 and $0.63 in Q1/04. Lower-than-expected results from Petroleum Transportation were largely offset by higher-than-expected results from Water and Utility Services and Other Activities. As expected, petroleum transportation throughput was negatively impacted by a temporary decline in production from the Alberta oilsands and refinery turnarounds.
- **Guidance for 2005 unchanged.** Notwithstanding the decline in first quarter results, Terasen's management is confident that it will achieve its target of 6% EPS growth in 2005. In the second quarter, Trans Mountain returned to operating at full capacity and was at 35% apportionment for May nominations. Management expects throughput to remain strong through the remainder of the year. Further, the recent completion of the Express pipeline expansion should provide increased earnings through the remainder of the year. Based on this outlook, we remain comfortable with our 2005 EPS estimate.
- **Outlook for 2006 still somewhat uncertain**. The earnings outlook for 2006 will depend on the outcome of Trans Mountain's negotiations with its shippers on the renewal of the existing Incentive Toll Settlement (ITS), which expires at the end of 2005. Given the preliminary nature of Trans Mountain's negotiations with its shippers, Terasen's management was unable to provide guidance with respect to the expected impact of the ITS renewal. Developments with respect to Terasen's TMX Project could also impact 2006 earnings. Pending additional information on the outcome of the ITS negotiations and the TMX project, we are maintaining our 2006 EPS estimate at this time.
- **Business development activities continue.** Terasen continues to work on a number of potential growth opportunities including development of the TMX Project and LNG Storage Facility, as well as the expansion of the Corridor Pipeline and Express System.
- **Valuation.** Our target price of $32.00 reflects a 12-month dividend distribution one-year forward of $0.97 and a required dividend yield of 2.95%.

Details

In general, the Q1/05 results were in line with our expectations. Terasen's normalized EPS were $0.60 in Q1/05 compared to our estimate of $0.61 and $0.63 in Q1/04. Lower-than-expected results from Petroleum Transportation were largely offset by higher-than-expected results from Water and Utility Services and Other Activities. As expected, petroleum transportation throughput was negatively impacted by a temporary decline in production from the Alberta oilsands, as well as maintenance turnarounds at refineries connected the Trans Mountain pipeline. Terasen's first quarter financial results are summarized in Exhibit 1.

Exhibit 1: Financial Results Summary ($MM Except EPS or Otherwise Indicated)

	For 3 months Ended Mar. 31			
	2005	2004	RBC CM Est. Q1/05	Comments
Natural Gas Distribution				
Terasen Gas	$ 49.0	$ 48.0	$ 48.9	Operating efficiencies and customer growth more than offset lower allowed ROE in 2005.
Terasen Gas (Vancouver Island)	6.7	6.7	6.6	
	55.7	54.7	55.5	
Petroleum Transportation				
Trans Mountain	5.4	10.4	6.6	Q1/05 results negatively impacted by production outages in the Alberta oilsands and refinery turnarounds.
Corridor	3.6	3.9	4.0	Lower allowed return on equity in Q1/05.
Express	3.7	4.0	4.3	Q1/05 results negatively impacted by production outages in the Alberta oilsands
	12.7	18.3	14.9	
Water and Utility Services	0.8	-	(0.0)	
Other Activities	(5.5)	(6.8)	(6.5)	Q1/05 results reflect lower corporate expenses and improved operations at Clean Energy.
Normalized earnings	$ 63.7	$ 66.2	$ 63.9	
Normalization adjustments:				
Mark-to-market gain at Clean Energy	2.6	1.7		
Reported earnings	$ 66.3	$ 67.9	$ 63.9	
Weighted average shares outstanding (MM)	105.3	104.4	105.2	
Normalized EPS	$ 0.60	$ 0.63	$ 0.61	

Source: Terasen; RBC Capital Markets

Natural Gas Distribution

Normalized earnings from Natural Gas Distribution were $49.0 million in Q1/05 compared to $48.0 million in Q1/04. Operating efficiencies and customer growth at Terasen Gas more than offset the lower allowed rate of return on equity in 2005.

Petroleum Transportation

Normalized earnings from Petroleum Transportation were $12.7 million in Q1/05 compared to earnings of $18.3 million in Q1/04. The first quarter results were negatively impacted by lower throughput volumes on Trans Mountain's mainline, which were attributable to temporary production outages in the Alberta oilsands and refinery turnarounds. In Q1/05, throughput averaged 170,000 bpd on Trans Mountain's Canadian mainline and 44,500 bpd on the U.S. mainline. In comparison, throughput averaged 240,400 bpd on the Canadian mainline and 93,300 bpd on the U.S. mainline in Q1/04. Based on March 2005 presentation by Terasen to the National Energy Board, we had expected Q1/05 throughput of approximately 175,000 bpd on the Canadian mainline and 40,000 bpd on the U.S. mainline.

Earnings from the Express System decreased from $4.0 million in Q1/04 to $3.7 million in Q1/05. The Q1/05 contribution from Express was also negatively impacted by the temporary production outages in the Alberta oilsands. Reflecting a lower allowed return on equity, earnings from the Corridor Pipeline declined by $0.3 million from $3.9 million in Q1/04 to $3.6 million Q1/05.

Water and Utility Services

Normalized earnings from Water and Utility Services increased from nil in Q1/04 to $0.8 million in Q1/05. The increase reflected continued growth in the base waterworks and utility service business combined with a small contribution from Fairbanks Sewer and Water Inc., which was acquired on July 31, 2004.

Other Activities

Excluding mark-to-market gains for natural gas derivative positions at Clean Energy, normalized earnings from Other Activities increased from ($6.8) million in Q1/04 to ($5.5) million in Q1/05. The increase was attributed to a reduction in corporate expenses and improved operations at Clean Energy.

EPS Estimates

Notwithstanding the decline in first quarter results, Terasen's management is confident that it will achieve its target of 6% EPS growth in 2005. In the second quarter, Trans Mountain returned to operating at full capacity and was at 35% apportionment for May nominations. Management expects throughput to remain strong through the remainder of the year. Further, the recent completion of the Express pipeline expansion should provide increased earnings through the remainder of the year. Based on the Q1/05 results and the expected outlook for the remainder of the year, we remain comfortable with our 2005 EPS estimate at this time.

The earnings outlook for 2006 will depend on the outcome of Trans Mountain's negotiations with its shippers on the renewal of the existing Incentive Toll Settlement (ITS), which expires at the end of 2005. In our financial forecast, we have assumed a $3 million decline in earnings at Trans Mountain in 2006 compared to 2004. Our 2006 EPS estimate would be negatively impacted if the renewal of the ITS reduced Trans Mountain's annual earnings contribution below $36 million. Given the preliminary nature of Trans Mountain's negotiations with its shippers, Terasen's management was unable to provide guidance with respect to the expected impact of the ITS renewal. Developments with respect to Terasen's TMX Project could also impact 2006 earnings. Pending additional information on the outcome of the ITS negotiations and the TMX project, we are maintaining our 2006 EPS estimate at this time.

Outlook

TMX Project

Terasen continues to work on its TMX project including developing the technical, regulatory and commercial components of the project. The pump station expansion project, which falls under the first phase of the TMX project, has received good interest from shippers. Through the construction of 13 new pump stations, the $205 million project would add 35,000 bpd of incremental capacity in 2006. Terasen is also working with potential domestic and overseas shippers on finalizing an interim commercial and tolling framework in the second quarter prior to holding an open season for long-term commitments for the first phase of the project. The open season could be held as early as June or July 2005.

Corridor Pipeline

Shell Canada recently filed regulatory applications to expand the capacity at its Muskeg River Mine and Scotford Upgrader. To accommodate the expected increase in production volumes, Terasen is actively working with Shell and its partners in the Athabasca Oil Sands Project on potentially expending the Corridor Pipeline from 155,000 bpd to 300,000 bpd by 2009 with 90,000 bpd increments every two years thereafter. Terasen is presently working on the first phase of the project, which consists of de-bottlenecking the existing system by adding pumping capacity at an estimated cost of $6.5 million. The first phase is expected to be in service by the fall of 2005. The second phase would expand the Corridor Pipeline by an additional 110,000 bpd at an estimated cost of $700 million to $800 million. Terasen is also working on expansion opportunities to ship third party volumes on the Corridor Pipeline.

Express System

In April 2005, Terasen completed its expansion plans for the Express System increasing total capacity by 108,000 bpd to 280,000 bpd at a total cost of approximately US$100 million. Approximately 84% of the total capacity is committed under long-term contracts. Terasen expects to start shipping uncommitted volumes in June or July 2005. The company has started to work on further expansion opportunities of the Express System to provide incremental capacity into PADD II, PADD V or possibly PADD III.

LNG Storage Facility

Terasen Gas Vancouver Island (TGVI) is working with BC Hydro on finalizing a long-term Transportation Service Agreement (TSA) to serve the Duke Point Power Project on Vancouver Island. In February 2005, the British Columbia Utilities Commission (BCUC) approved the construction of a liquefied natural gas storage facility on Vancouver Island subject to the execution of the TSA. According to Terasen, it has made substantial progress with respect to its negotiations with BC Hydro.

In April 2005, a B.C. Court of Appeal judge dismissed an appeal motion filed by third parties seeking to overturn the BCUC's decision to approve BC Hydro's electricity purchase agreement with Pristine Power, which will construct the Duke Point Power Project. The third parties have filed a request to have a three-judge Appeal Court panel review the original ruling and a hearing has been set for June 3, 2005. Notwithstanding the appeal hearing, Terasen remains optimistic that the LNG storage facility will proceed ahead.

Summary

The Q1/05 results were generally in line with our expectations. We remain comfortable with our current 2005 EPS estimate. Terasen's 2006 earnings outlook is somewhat unclear given the expiry of Trans Mountain's current ITS and the uncertainty with respect to its renewal. On the positive side, Terasen has a number of potential organic growth opportunities within its existing businesses.

Valuation

Our valuation for Terasen is largely based on a dividend yield approach. When the current yield of the ten-year Government of Canada benchmark bond is below 6%, we believe that a dividend yield approach is an appropriate valuation method for Terasen. Our target price of $32.00 reflects a 12-month dividend distribution one-year forward of $0.96 and a required dividend yield of 2.95%.

Price Target Impediments

Factors that could have negative implications for Terasen's earnings and our target price include unexpected increases in operating costs that are unrecoverable under its incentive agreements, failure to renew Trans Mountain's Incentive Toll Settlement after the end of 2005 and a significant and prolonged decline in Western Canadian petroleum production.

Company Description

Terasen is engaged in the transmission and distribution of natural gas and the transportation of crude oil and refined products.

Required Disclosures

Explanation of RBC Capital Markets Rating System

An analyst's "sector" is the universe of companies for which the analyst provides research coverage. Accordingly, the rating assigned to a particular stock represents solely the analyst's view of how that stock will perform over the next 12 months relative to the analyst's sector.

Ratings
Top Pick (TP): Represents best in Outperform category; analyst's best ideas; expected to significantly outperform the sector over 12 months; provides best risk-reward ratio; approximately 10% of analyst's recommendations.
Outperform (O): Expected to materially outperform sector average over 12 months.
Sector Perform (SP): Returns expected to be in line with sector average over 12 months.
Underperform (U): Returns expected to be materially below sector average over 12 months.

Risk Qualifiers (any of the following criteria may be present):
Average Risk (Avg): Volatility and risk expected to be comparable to sector; average revenue and earnings predictability; no significant cash flow/financing concerns over coming 12-24 months; fairly liquid.
Above Average Risk (AA): Volatility and risk expected to be above sector; below average revenue and earnings predictability; may not be suitable for a significant class of individual equity investors; may have negative cash flow; low market cap or float.
Speculative (Spec): Risk consistent with venture capital; low public float; potential balance sheet concerns; risk of being delisted.

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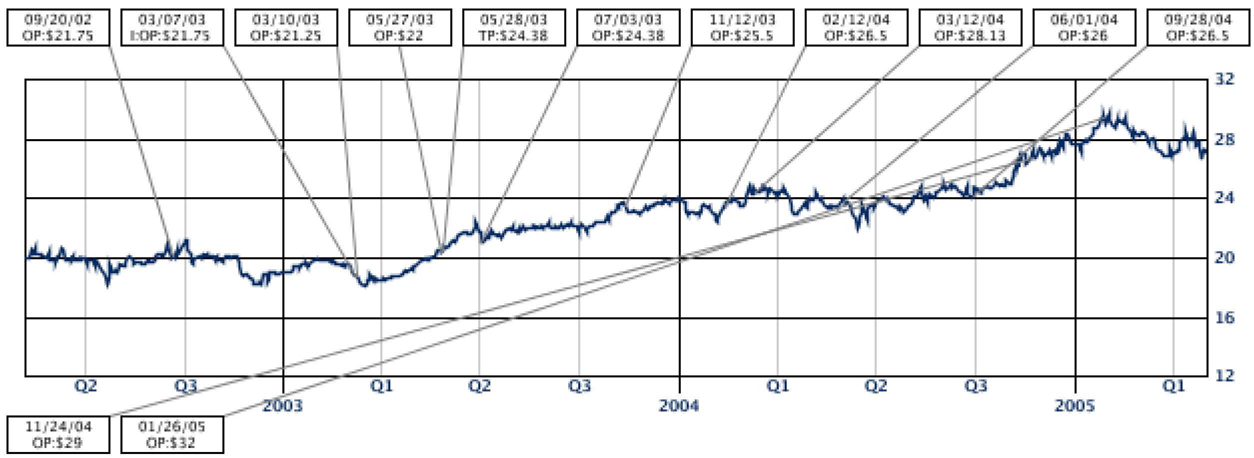
Distribution of Ratings, Firmwide

	RBC Capital Markets		Investment Banking Serv./Past 12 Mos.	
Rating	Count	Percent	Count	Percent
BUY [TP/O]	398	43.45	132	33.17
HOLD [SP]	433	47.27	134	30.95
SELL [U]	85	9.28	25	29.41

Rating and Price Target History for: Terasen Inc. as of 05-03-2005



Legend:
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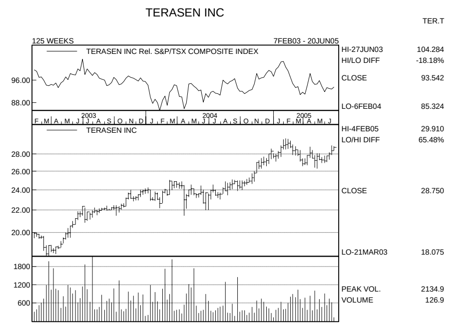

Terasen Inc.

(TSX: TER)

Outperform

Average Risk

Financial Estimates Revised to Reflect BC Hydro's Cancellation of the Duke Point Power Project

Fai Lee, CGA, CFA
(604) 257-7662
fai.lee@rbccm.com

Price:	$28.75	Price Target:	$32.50
52-Wk High:	$29.91	52-Wk Low:	$22.02
Float (MM):	105.4	Debt-to-Cap:	0.68
Shs O/S (MM):	114.6	Mkt Cap (MM):	$3,031
Dividend:	$0.90	Yield:	3.1%

Strategic Shareholders: Trans Mountain - 8.0%

(FY Dec 31)	2004A	2005E	2006E	2007E
EPS				
Old Basic	$1.40	$1.48	$1.57	$1.60
Old Diluted	$1.39	$1.47	$1.56	$1.59
Basic	$1.40	$1.48	$1.56	$1.58
Diluted	$1.39	$1.47	$1.55	$1.57
P/E	20.5	19.4	18.4	18.2
EPS	Q1	Q2	Q3	Q4
2003A	$0.62	$0.18	$0.03	$0.54
2004A	$0.63	$0.17	$0.08	$0.52
2005E	$0.60A	$0.22	$0.12	$0.54

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EPS are normalized for unusual and non-recurring items

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Maureen Howe, a member of the Canadian pipelines and utilities team, is an associate of an insider of Terasen Inc., a component of the pipelines and utilities sector.

Event

BC Hydro recently abandoned its Duke Point Power Project.

Investment Opinion

- **Unexpected decision from BC Hydro.** BC Hydro recently decided to abandon its proposed $285 million Duke Point Power Project. The provincially owned utility claimed that the B.C. Court of Appeal's decision to hear an appeal of the project by a number of intervenors resulted in a great risk that the plant would not be built in time. We had not expected this decision given the progress that had been made on the project.
- **Decision may mean potential delay for Terasen's LNG storage facility.** Terasen had been working with BC Hydro on finalizing a long-term Transportation Service Agreement that would have resulted in the construction of a LNG storage facility to serve the Duke Point Power Project. Notwithstanding BC Hydro's decision, Terasen's management believes that there still could be a need for its proposed LNG storage facility in the future. As a result, Terasen is considering the possibility of filing for regulatory approval to construct the facility at a later date.
- **EPS estimates reduced to reflect regulatory uncertainty**. Given the uncertainty regarding whether the provincial regulator will approve another application for a LNG storage facility on Vancouver Island, we have decided to exclude the potential impact of the LNG facility from our financial forecast. Accordingly, we have reduced our 2006 and 2007 EPS estimates for Terasen from $1.57 and $1.60, respectively, to $1.56 and $1.58.
- **Valuation.** Our target price of $32.50 (unchanged) reflects a 12-month dividend distribution one-year forward of $0.98 and a required dividend yield of 3.0%.

Details

BACKGROUND

BC Hydro recently decided to abandon its proposed $285 million Duke Point Power Project on Vancouver Island. The provincially owned utility claimed that the B.C. Court of Appeal's decision to hear an appeal of the project by a number of intervenors resulted in a great risk that the plant would not be built in time.

We were surprised by BC Hydro's decision, particularly given the progress that had been made on the project. BC Hydro had already spent $70 million on turbines and other equipment related to the project. This amount does not include the $50 million spent on the Georgia Strait Crossing (GSX) pipeline project that was cancelled in late 2004. The GSX project was designed to supply natural gas to BC Hydro's power plant and other facilities on Vancouver Island.

Following the cancellation of the GSX project, Terasen Gas Vancouver Island (TGVI) had been working with BC Hydro on finalizing a long-term Transportation Service Agreement (TSA) to serve the Duke Point Power Project. In February 2005, the British Columbia Utilities Commission (BCUC) approved Terasen's application to construct a liquefied natural gas storage facility on Vancouver Island subject to the execution of the TSA.

IMPLICATIONS

Notwithstanding BC Hydro's decision, Terasen's management believes that there still could be a need for its proposed LNG storage facility on Vancouver Island in the future. As a result, Terasen is considering the possibility of filing another application with the BCUC for the construction of the LNG storage facility at a later date.

Given the uncertainty regarding whether the BCUC will approve another application for a LNG storage facility on Vancouver Island, we have decided to exclude the potential impact of the LNG facility from our financial forecast. Accordingly, we have reduced our 2006 and 2007 EPS estimates for Terasen from $1.57 and $1.60, respectively, to $1.56 and $1.58.

Valuation

Our valuation for Terasen is largely based on a dividend yield approach. When the current yield of the ten-year Government of Canada benchmark bond is below 6%, we believe that a dividend yield approach is an appropriate valuation method for Terasen. Our target price of $32.50 reflects a 12-month dividend distribution one-year forward of $0.98 and a required dividend yield of 3.0%.

Price Target Impediments

Factors that could have negative implications for Terasen's earnings and our target price include unexpected increases in operating costs that are unrecoverable under its incentive agreements, failure to renew Trans Mountain's Incentive Toll Settlement after the end of 2005 and a significant and prolonged decline in Western Canadian petroleum production.

Company Description

Terasen is engaged in the transmission and distribution of natural gas and the transportation of crude oil and refined products.

Required Disclosures

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An analyst's "sector" is the universe of companies for which the analyst provides research coverage. Accordingly, the rating assigned to a particular stock represents solely the analyst's view of how that stock will perform over the next 12 months relative to the analyst's sector.

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Top Pick (TP): Represents best in Outperform category; analyst's best ideas; expected to significantly outperform the sector over 12 months; provides best risk-reward ratio; approximately 10% of analyst's recommendations.
Outperform (O): Expected to materially outperform sector average over 12 months.
Sector Perform (SP): Returns expected to be in line with sector average over 12 months.
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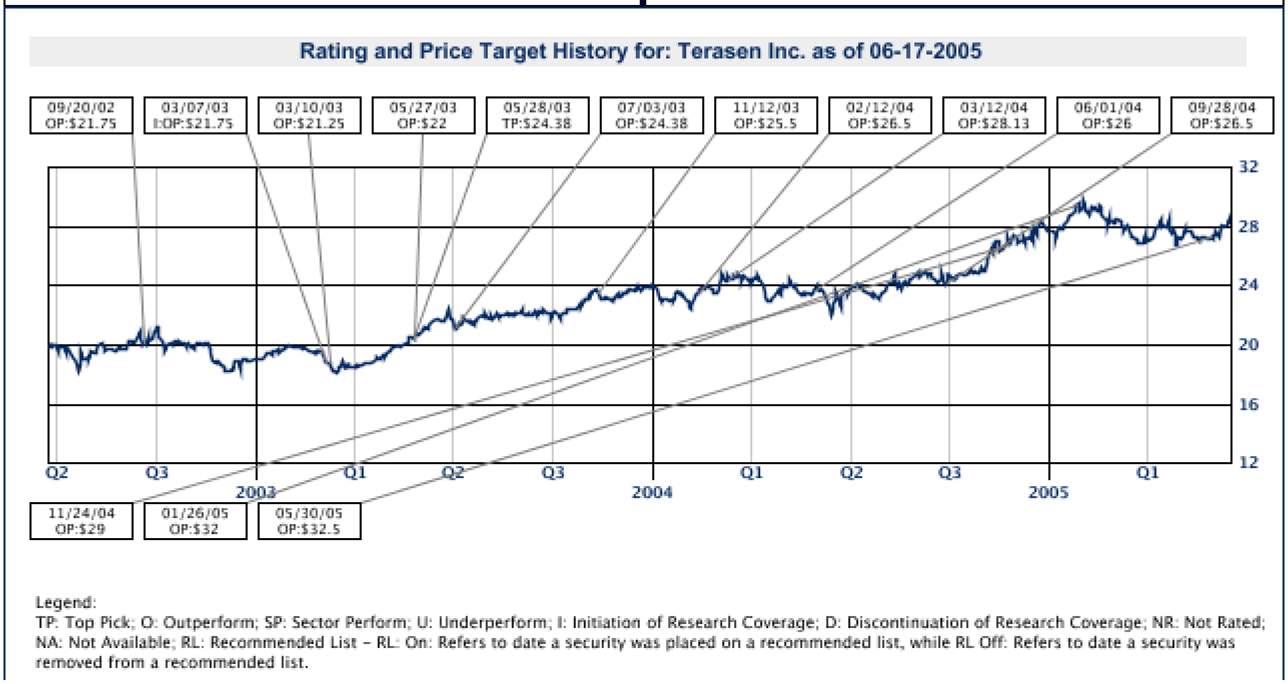
HOLD [SP]	437	47.76	128	29.29
SELL [U]	80	8.74	28	35.00



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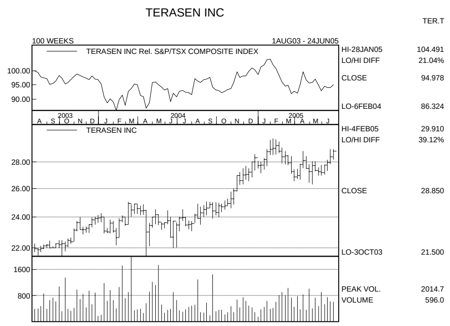
RBC Capital Markets

Research Comment

June 27, 2005



Terasen Inc.

(TSX: TER)

Outperform

Average Risk

Enbridge Tolling Agreement Encouraging for Terasen

Fai Lee, CGA, CFA
(604) 257-7662
fai.lee@rbccm.com

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Event

Enbridge reached an agreement with the Canadian Association of Petroleum Producers (CAPP) on a new incentive tolling settlement.

Investment Opinion

- **No widespread rebasing of tolls.** CAAP did not seek a complete rebasing of Enbridge's tolls. Instead, Enbridge's earnings base was reduced to account for the difference between the 2005 National Energy Board Multi-Pipeline return on equity and the implied return reflected in Enbridge's 1994 base tolls. If we apply a similar adjustment for Terasen, we arrive at a $4 million reduction to the earnings base for Terasen's Trans Mountain system. After normalizing for the temporary decline in Trans Mountain's throughput in Q1/05, this level of reduction is consistent with our current 2006 financial forecast for Terasen.
- **Possible incentive opportunities.** Under its agreement with CAPP, Enbridge will have the opportunity to realize bonuses for improving batch quality, delivery predictability and capacity reliability. Through these bonuses and cost savings, Enbridge expects to partially mitigate the impact of the decline in its earnings base. Based on discussions with Terasen's management, we expect similar types of incentives to be incorporated into any agreement that Terasen may reach with CAPP.
- **Focus on service quality rather than cost reduction.** As observed in Enbridge's agreement, we expect CAPP to focus more on the issue of providing proper incentives to meet service targets instead of reducing overall pipeline tolls in its negotiations with Terasen.
- **Encouraged by Enbridge's agreement.** In recent months, Terasen's share performance has lagged behind other energy infrastructure stocks. We believe that Terasen's underperformance may be related to concerns over the renewal of its existing incentive toll settlement for Trans Mountain. We view Enbridge's agreement as encouraging and recommend investors consider increasing their weighting in Terasen at this time.
- **Valuation.** Our target price of $32.50 (unchanged) reflects a 12-month dividend distribution one-year forward of $0.98 and a required dividend yield of 3.0%.

Details

BACKGROUND

On Friday, Enbridge announced that it had reached an agreement with CAPP on the key terms of a new 5-year incentive tolling settlement effective January 1, 2005. The new incentive tolling settlement outlines the methodology for calculating base tolls on the Enbridge mainline system over the five-year period. For additional details on Enbridge's incentive tolling settlement, please refer to our June 27th *Morning Comment* for Enbridge.

Enbridge's previous incentive tolling settlement expired on December 31, 2004. Similar to Enbridge, Terasen has been in discussions with CAPP on renewing its incentive toll settlement (ITS) for the Trans Mountain system before it expires on December 31, 2005. Given the earlier expiry of Enbridge's incentive tolling settlement, CAPP has been more focused on completing its negotiations with Enbridge than negotiating with Terasen. With Enbridge's settlement finalized, we expect CAPP to focus its attention on reaching a new agreement with Terasen for the Trans Mountain system.

IMPLICATIONS FOR TERASEN

We should emphasize that Terasen's existing ITS for the Trans Mountain system is quite different from Enbridge's agreement with CAPP. For example, Terasen has some exposure to throughput risk under its agreement, whereas Enbridge does not. Given these differences, it is somewhat difficult to apply the terms of Enbridge's new agreement to arrive at an accurate prediction of a possible agreement for Terasen. Nevertheless, we will attempt to extrapolate some general implications for Terasen from Enbridge's new agreement with CAAP.

No Widespread Rebasing of Tolls

CAAP did not seek a complete rebasing of Enbridge's tolls. Instead, Enbridge's earnings base was only reduced by $10.9 million after taking into account $6 million of non-routine adjustments rolled into the earnings base. The reduction largely reflects an adjustment to account for the difference between the 2005 National Energy Board (NEB) Multi-Pipeline return on equity and the implied return reflected in Enbridge's 1994 base tolls. When Enbridge's original agreement was reached in 1994, the allowed return on equity implied by the base toll was 12.5%. In comparison, the 2005 NEB Multi-Pipeline ROE is 9.46%. According to Enbridge, the rate base for its mainline system is in the range of $1 billion. If we assume a rate base of $800 million and a 45% common equity component, the reduction in Enbridge's earnings base can be almost entirely accounted for by the difference between current NEB Multi-Pipeline ROE and the implied ROE in 1994 ($800 million X 45% X 300 bps ≈ $10.9 million).

If we applied a similar adjustment to Terasen using an assumed rate base of $300 million, a 45% common equity component and a 300 basis point differential, we would arrive at a reduction to Trans Mountain's earnings base of about $4 million. After normalizing for the temporary decline in Trans Mountain's throughput in Q1/05, this level of reduction is consistent with our current 2006 financial forecast for Terasen.

Opportunities to Offset Lower Earnings Base

Under its agreement with CAPP, Enbridge will have the opportunity to realize bonuses for improving batch quality, delivery predictability and capacity reliability. Through these bonuses and cost savings, Enbridge expects to partially mitigate the impact of the decline in its earnings base. Based on discussions with Terasen's management, we expect similar types of incentives to be incorporated into any agreement that Terasen may reach with CAPP.

We believe that improved service quality has a greater financial benefit to shippers than a small reduction in tolls. With oil prices at almost US$60 per barrel, the pipeline toll (approx. US$1.30/bbl for Trans Mountain) represents a small percentage of producers' revenue on a per barrel basis. To realize the benefit of high oil prices, producers need to have their product delivered in a timely and reliable fashion. As observed in Enbridge's agreement, we expect CAPP to focus more on the issue of providing proper incentives to meet service targets instead of reducing overall pipeline tolls in its negotiations with Terasen.

Conclusion

Based on the outcome of Enbridge's agreement with CAPP, we do not expect a significant negative financial impact for Terasen associated with its ITS renewal. In recent months, Terasen's share performance has lagged behind other energy infrastructure stocks. We believe that Terasen's underperformance may be related to concerns over the ITS renewal. We view Enbridge's agreement as encouraging and recommend investors consider increasing their weighting in Terasen at this time.

Valuation

Our valuation for Terasen is largely based on a dividend yield approach. When the current yield of the ten-year Government of Canada benchmark bond is below 6%, we believe that a dividend yield approach is an appropriate valuation method for

Terasen. Our target price of $32.50 reflects a 12-month dividend distribution one-year forward of $0.98 and a required dividend yield of 3.0%.

Price Target Impediments

Factors that could have negative implications for Terasen's earnings and our target price include unexpected increases in operating costs that are unrecoverable under its incentive agreements, failure to renew Trans Mountain's Incentive Toll Settlement after the end of 2005 and a significant and prolonged decline in Western Canadian petroleum production.

Company Description

Terasen is engaged in the transmission and distribution of natural gas and the transportation of crude oil and refined products.

Required Disclosures

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Outperform (O): Expected to materially outperform sector average over 12 months.
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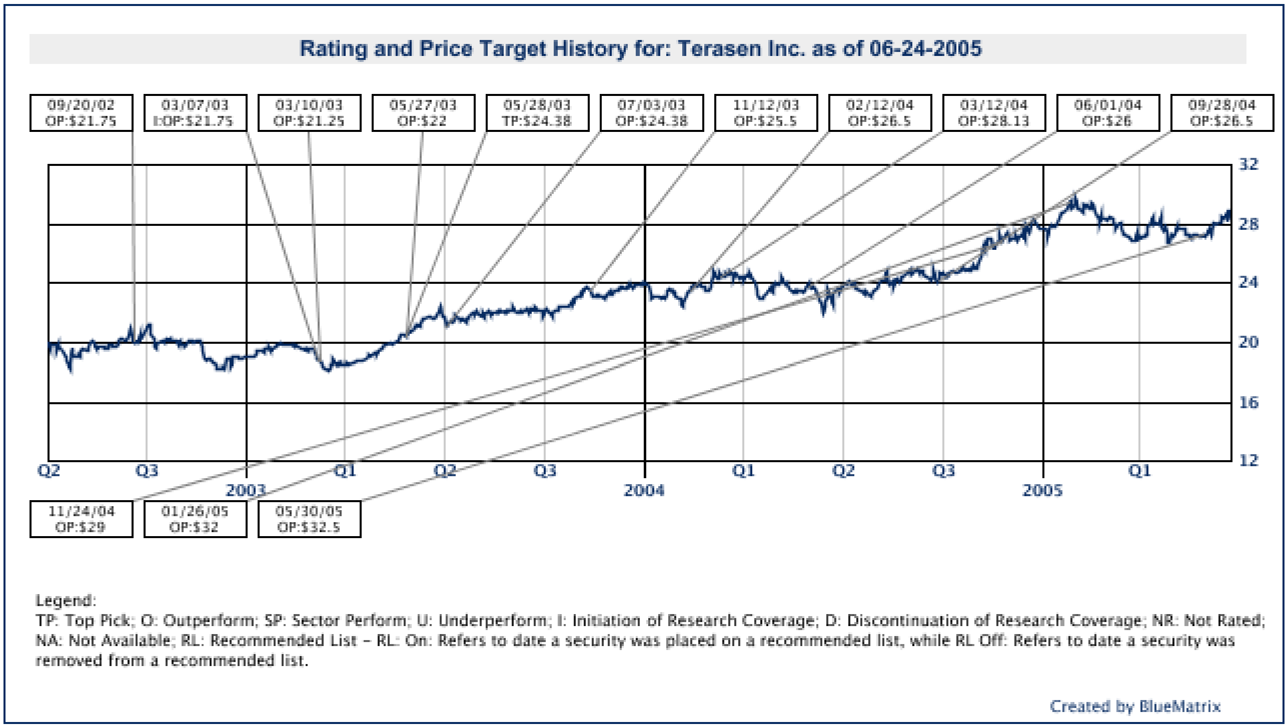
	RBC Capital Markets		Investment Banking Serv./Past 12 Mos.	
Rating	Count	Percent	Count	Percent
BUY [TP/O]	394	42.92	138	35.03
HOLD [SP]	443	48.26	129	29.12
SELL [U]	81	8.82	28	34.57



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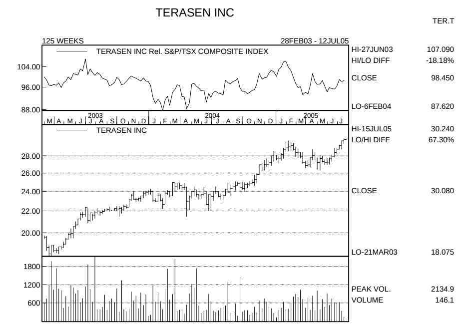
RBC Capital Markets

Research Comment

July 13, 2005



Terasen Inc.

(TSX: TER)

Outperform

Average Risk

Regulatory Application Filed for Phase One of Trans Mountain Expansion Project

Fai Lee, CGA, CFA (Analyst)
(604) 257-7662
fai.lee@rbccm.com

Price:	$30.08	Price Target:	$36.00
52-Wk High:	$29.91	52-Wk Low:	$23.07
Float (MM):	105.4	Debt-to-Cap:	0.68
Shs O/S (MM):	114.6	Mkt Cap (MM):	$3,171
Dividend:	$0.90	Yield:	3.0%

Strategic Shareholders: Trans Mountain - 8.0%

(FY Dec 31)	2004A	2005E	2006E	2007E
EPS				
Basic	$1.40	$1.48	$1.56	$1.58
Diluted	$1.39	$1.47	$1.55	$1.57
P/E	21.5	20.3	19.3	19.0
EPS	Q1	Q2	Q3	Q4
2003A	$0.62	$0.18	$0.03	$0.54
2004A	$0.63	$0.17	$0.08	$0.52
2005E	$0.60A	$0.22	$0.12	$0.54

All values in C$ unless otherwise noted.

EPS are normalized for unusual and non-recurring items and may not be consistent with GAAP.

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Priced as of prior trading day's market close, EST (unless otherwise stated).

Maureen Howe, a member of the Canadian pipelines and utilities team, is an associate of an insider of Terasen Inc., a component of the pipelines and utilities sector.

Event

Terasen Pipelines filed an application with the National Energy Board to expand the Trans Mountain pipeline system.

Investment Opinion

- **Trans Mountain capacity will increase from 225,000 bpd to 260,000 bpd.** The $210 million expansion will add 35,000 bpd of heavy crude oil capacity through new pump station facilities. Pending regulatory approval, the new capacity is expected to be in service by April 2007.
- **Shippers are supportive of expansion.** The Canadian Association of Petroleum Producers (CAPP) has expressed its support for the project subject to the successful negotiation of tolling and operational arrangements. The tolling treatment for the new facilities is expected to be linked to the discussions on the renewal of Trans Mountain's Incentive Toll Settlement (ITS), which expires at the end of 2005.
- **Expansion represents first step in multi-phased expansion project.** The next phase of expansion is expected to commence in August when Terasen will hold an open season for the construction of a 30-inch pipeline loop between Hinton, Alberta and Valemount, B.C. Subject to necessary approvals, the new loop would increase Trans Mountain's capacity from 260,000 bpd to 300,000 bpd by the end of 2008 at an estimated cost of $365 million.
- **EPS impact difficult to determine at this time.** On a standalone basis, we estimate a full-year EPS impact of approximately $0.06 to $0.07 per share from the pump station expansion project based on our assumptions. However, the ultimate EPS impact to Terasen is difficult to determine at this time given the linking of the negotiations on the tolling treatment for the new pump station facilities with discussions on the renewal of Trans Mountain's ITS. Pending additional information on the final tolling arrangements, we are maintaining our EPS estimates at this time.
- **Announcement very positive sign for Terasen.** We believe yesterday's announcement highlights the advantages of Terasen's phased expansion approach for Trans Mountain as opposed to a greenfield pipeline project that would take considerably longer to develop. Further, we believe the announcement is indicative of producers' support for significant new pipeline capacity from Alberta to the west coast of British Columbia.
- **Valuation.** Our target price of $36.00 (unchanged) reflects a 12-month dividend distribution one-year forward of $0.98 and a required dividend yield of 2.75%.

Details

Terasen Pipelines filed an application with the National Energy Board to increase the capacity of the Trans Mountain pipeline system from 225,000 barrels per day (bpd) to 260,000 bpd. The $210 million expansion will add 35,000 bpd of heavy crude oil capacity through new and upgraded pump stations along the pipeline system between Edmonton, Alberta and Burnaby, B.C. Pending regulatory approval, the new capacity is expected to be in service by April 2007.

The expansion project has the support of the shippers, as represented by the Canadian Association of Petroleum Producers, subject to the successful negotiation of tolling and operational arrangements for the project between CAPP and Terasen. Terasen expects the tolling treatment for the new facilities to be linked to the discussions on the renewal of Trans Mountain's Incentive Toll Settlement, which expires at the end of 2005. According to Terasen, it has made concrete progress on its ITS renewal negotiations with CAPP.

The pump station expansion represents the first step in Terasen's proposed multi-phased expansion of the Trans Mountain system. The next phase is expected to commence in August when Terasen will hold an open season for the construction of a 30-inch pipeline loop between Hinton, Alberta and Valemount, B.C. (the "Anchor Loop"). Subject to necessary approvals, the Anchor Loop would increase Trans Mountain's capacity from 260,000 bpd to 300,000 bpd by the end of 2008 at an estimated cost of $365 million.

Implications For Terasen

On a standalone basis, we estimate a full-year EPS impact of approximately $0.06 to $0.07 per share from the pump station expansion project based on our assumptions. In our analysis, we assumed a realized ROE of 12% and a deemed common equity component of 45%. In addition, we assumed financing of required project equity with an issuance of new shares under Scenario 1 and financing with internally generated funds at an after-tax opportunity cost of 4% under Scenario 2. Our analysis is outlined in Exhibit 1.

Exhibit 1 – Estimated EPS Impact on a Standalone Basis ($MM except per share amounts or otherwise indicated)

	2008E
Pump station expansion capital cost	$210.0
Deemed common equity component	45.0%
Deemed common equity	$94.5
Realized ROE	12.0%
Earnings contribution from expansion	$11.3
Scenario 1 - Financing with New Shares	
Shares outstanding before pump station expansion	104.9
Shares issued @ $36.00 per share to finance expansion	2.6
Total shares (MM)	107.5
EPS impact before dilution	$0.11
Dilution based on assumed 6% annual EPS growth	($0.04)
Estimated EPS Impact	$0.06
Scenario 2 - Financing with Internally Generated Funds	
Earnings impact before opportunity cost of equity	$11.3
After-tax opportunity cost of equity at 4.0%	(3.8)
Estimated earnings impact	$7.6
Estimated EPS impact	$0.07

Source: Company reports, RBC Capital Markets estimates

Notwithstanding our analysis, the ultimate EPS impact to Terasen is difficult to determine at this time given the linking of the negotiations on the tolling treatment for the new pump station facilities with discussions on the renewal of Trans Mountain's ITS. In our financial forecast, we had assumed a modest negative financial impact to Terasen in 2006 related to the renewal of the ITS. In its negotiations with CAPP, Terasen may forego some of the financial benefit associated with the pump station expansion project in order to mitigate any negative financial impact in 2006 related to the ITS renewal. According to Terasen, CAPP is receptive to the concept of stabilizing Trans Mountain's tolls over the next few years instead of having tolls decline in 2006 due to the ITS renewal and increase in 2007 and 2008 due to the pump station expansion project. Pending additional information on the final tolling arrangements, we are maintaining our EPS estimates at this time.

We believe yesterday's announcement highlights the advantages of Terasen's phased expansion approach for Trans Mountain as opposed to a greenfield pipeline project that would take considerably longer to develop. Further, we believe the announcement is indicative of producers' support for significant new pipeline capacity from Alberta to the west coast of British Columbia.

Valuation

Our valuation for Terasen is largely based on a dividend yield approach. When the current yield of the ten-year Government of Canada benchmark bond is below 6%, we believe that a dividend yield approach is an appropriate valuation method for Terasen. Our target price of $36.00 reflects a 12-month dividend distribution one-year forward of $0.98 and a required dividend yield of 2.75%.

Price Target Impediments

Factors that could have negative implications for Terasen's earnings and our target price include unexpected increases in operating costs that are unrecoverable under its incentive agreements, failure to renew Trans Mountain's Incentive Toll Settlement after the end of 2005 and a significant and prolonged decline in Western Canadian petroleum production.

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Required Disclosures

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Ratings
Top Pick (TP): Represents best in Outperform category; analyst's best ideas; expected to significantly outperform the sector over 12 months; provides best risk-reward ratio; approximately 10% of analyst's recommendations.
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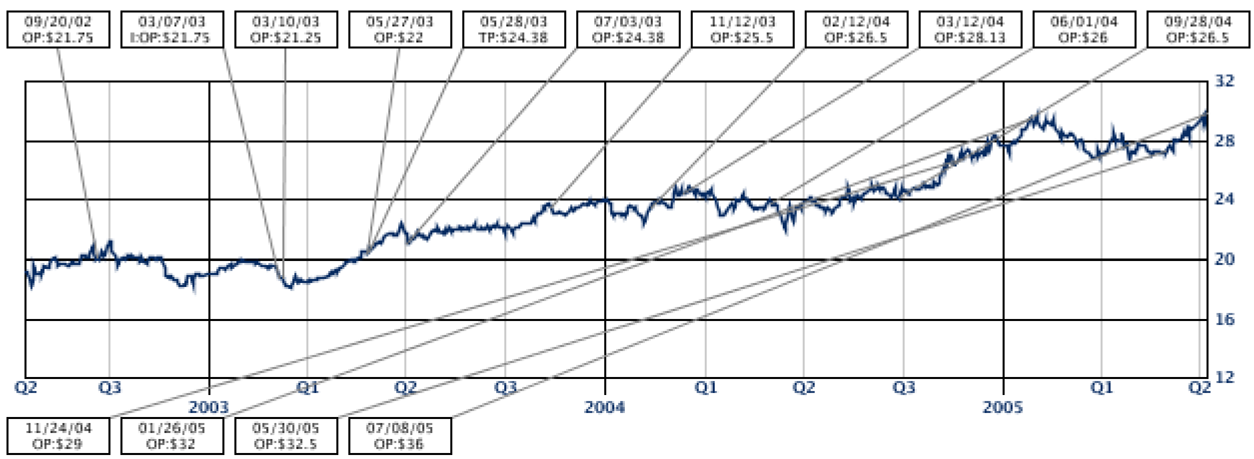
HOLD [SP]	436	47.86	129	29.59
SELL [U]	82	9.00	26	31.71

Rating and Price Target History for: Terasen Inc. as of 07-08-2005



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Equity Research DAILY Edge

Company Comment
Tuesday, February 01, 2005

Terasen Inc.

(TER-T C$29.35)

Sam Kanes, CA, CFA – 416-863-7798
sam_kanes@scotiacapital.com

Turan Quettawala, CFA – 416-863-7846
turan_quettawala@scotiacapital.com

Rating: 3-Sector Underperform	**Target**	1-Yr:	$27.00	**ROR**	1-Yr:	-5.0%	**Est. NTM Div.**	$0.88
Risk Ranking: Low		2-Yr:	$28.00		2-Yr:	1.4%	**Div. (Current)**	$0.84
Valuation: 1-yr target based on 17x P/E on 2006E EPS							**Yield**	2.9%

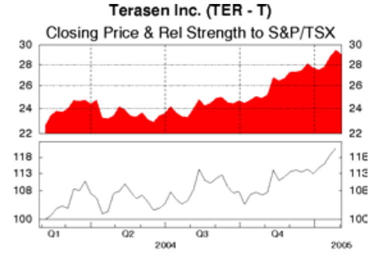
TMX Project Announcement

Event

- Terasen announced "strong support" by 17 different parties for its initial TMX oil pipeline expansion of 75,000 bbl/d.

What It Means

- Long term EPS growth from expanding its oil pipeline system appears more assured based on the press release. It is, however, the first step of several more that have to lead to long-term take-or pay shipper contracts for the project to go ahead.
- Terasen still does not believe that there is sufficient oil available before 2010 for both the Enbridge $2.5B Gateway and Terasen's TMX oil pipeline expansion projects to proceed at the same time.



Source: Global Insight, Inc.

Qtly EPS (Basic)	Q1	Q2	Q3	Q4	Year	P/E
2003A	0.71 A	0.08 A	-0.08 A	0.57 A	1.28	18.73
2004E	0.77 A	0.10 A	-0.01 A	0.59	1.45	19.11
2005E	0.80	0.11	-0.06	0.66	1.50	19.57
2006E	0.85	0.12	-0.05	0.69	1.60	18.34

(FY-Dec.)	2002A	2003A	2004E	2005E	2006E
Earnings	$1.22	$1.28	$1.45	$1.50	$1.60
Cash Flow	$2.75	$2.75	$2.86	$2.99	$3.16
Price/Earnings	15.6	18.7	19.1	19.6	18.3
Relative P/E	0.4	1.0	1.0	1.1	1.0
Revenues	$1707	$1877	$1853	$2098	$2156
EBITDA	$452	$505	$554	$581	$614
Current Ratio	0.6	0.6	0.6	0.6	0.6
EBITDA/Int. Exp	2.8	2.9	3.2	3.3	3.3

I/B/E/S Estimates	**BVPS**	$15.50	**Shares O/S (M)**	104.8
EPS 2004E: $1.41	**ROE**	9.9%	**Float O/S (M)**	104.8
EPS 2005E: $1.51			**Total Value ($M)**	3,075
			Float Value ($M)	3,075
Next Reporting Date	17-Feb-05		**TSX Weight**	0.33%
Credit Ratings	S&P: BBB/Stable			

Historical price multiple calculations use FYE prices. Source: Reuters; Company reports; Scotia Capital estimates.

Pertinent Revisions

	New	Old
Target:		
2-Yr	$28.00	$27.50

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For important disclosure information see Appendix A of this report.

Expression of Interest Information

- Terasen's management stated that the proposed confidentiality agreements limit the information it could provide to date. What Terasen asked for was:
  "1. Please provide incremental oil volumes that you plan to ship westbound to either the U.S., Canada or Asia over the next 10 years on a year by year basis and
  2. Please break out these incremental oil volumes you plan to ship by location, i.e. Burnaby, Washington State, Northern B.C. or Southern B.C. "
- **Next Steps:** Terasen stated that the response has led to an "obvious" need to proceed with a 2-3 month effort with the 17 parties to work out commercial arrangements. If successful, Terasen would then proceed to an Open Season to try to contract most/all of the initial 75,000 bbl/d of the TMX looping project. Terasen is targeting for a July 2005 completion.
- The first 75,000 bbl/d of Terasen's TMX expansion (phase 1) will be the costliest of the three phases that could lift volume shipped by 500,000 bbl/d over time. Terasen's TMX project is in direct competition with Enbridge's $2.5 B Gateway oil export project (See page 63-67 of our January 2005 *Gas and Electric Utilities Outlook*).
- The initial expressions of interest on any major pipeline project are not that significant as many pipeline projects have become "paper pipelines" if solid take-or-pay shipper contracts are not ultimately signed to support project financing. Enbridge stated that it was very close to getting several anchor shipper contracts from Asian shippers. If Enbridge is successful, it could delay Terasen's TMX project if it materially reduces Terasen's 17 expressions of interest into fewer than expected shipper contracts.

Valuation

- Both Terasen's and Enbridge's stocks have hit all-time highs many times in the past 4-5 weeks on their oil pipeline expansion prospects and huge flow of funds into defensive higher yielding equity products. We value Terasen one-year out at $27 per share using a 17x P/E on 2006 EPS of $1.60 per share. The only energy utility stock that we attribute a higher P/E multiple to is Enbridge at 18x. Terasen's stock at over $29 per share is currently trading at over 18x 2006 EPS. While we did not change our one-year target, we are increasing our two-year target by $0.50 per share for relatively better longer-term TMX looping pipeline prospects.
- We believe the stock market is paying a lot for Terasen's stock and EPS growth prospects of 6% per year. Terasen's debt to total cap is 67% which limits its EPS growth rate, while Enbridge is 700 bp lower at a 60% debt to total cap, which allows for a marginally higher EPS growth rate of about 8% per year. However, Terasen has many regulatory deferred accounts at its gas utility that protect its equity shareholders and allow for higher than normal debt leverage that is fully passed through to customers.
- Terasen's senior unsecured debt rating is BBB minus at S&P while ENB has an A minus credit rating from S&P. However, Terasen's rating under Moody's of A3/Stable is identical to Enbridge's. We understand that Terasen's debt trades at 15-20 basis points above Enbridge's so the market views Enbridge's debt as superior by one notch, not the three notches implied by S&P nor Moody's parity assumption.
- Terasen's dividend yield has gone under 3%, representing another record low for the interest sensitive energy utility sector. We believe that Terasen will raise its dividend by $0.06 per share in 2005 or 5%. Enbridge's dividend was raised by 9.3% recently to $2.00 per share. Our preference therefore remains Enbridge.

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Appendix A: Important Disclosures

Company	Ticker	Disclosures*
Enbridge Inc.	ENB	H3, S
Terasen Inc.	TER	H3
TransCanada Corporation	TRP	H3, S

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Medium
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High
High financial and/or operational risk, low predictability of financial results, high stock volatility.

Caution Warranted
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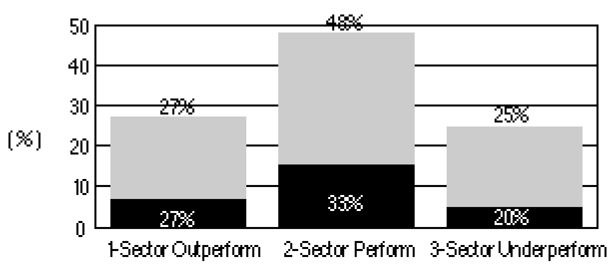

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* As at December 31, 2004.

Source: Scotia Capital.

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Company Comment
Friday, February 18, 2005

Terasen Inc.

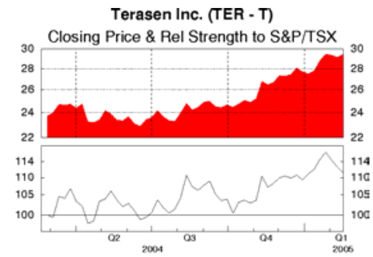
(TER-T C$29.34)

Sam Kanes, CA, CFA – 416-863-7798
sam_kanes@scotiacapital.com

Turan Quettawala, CFA – 416-863-7846
turan_quettawala@scotiacapital.com

Rating: 3-Sector Underperform	**Target** 1-Yr:	$29.00	**ROR** 1-Yr:	1.9%	**Est. NTM Div.**	$0.90
Risk Ranking: Low	2-Yr:	$28.00	2-Yr:	1.6%	**Div. (Current)**	$0.90
Valuation: 1-yr target based on 18x P/E on 2006E EPS					**Yield**	3.1%

Q4/04 EPS Lower Than Expected



Source: Global Insight, Inc.

Event

- TER reported Q4/04 EPS of $0.51/share that was lower than our and consensus estimates of $0.59/share. There were no non-recurring items, however, a change in accounting for income taxes in Q4/04 cost about $0.06/share and led to a restatement of quarterly earnings in prior periods such that the net effect on annual earnings was nil.

What It Means

- Earnings from gas distribution declined by 5% YOY mainly due to a lower allowed ROE that was only partly offset by cost efficiencies due to the integration of the mainland and Vancouver Island operations. Earnings from petroleum transportation were up 11% YOY driven by Trans Mountain and Express. TER's water and utility services also posted strong results.
- TER maintained its guidance of 6% growth in recurring EPS that implies 2005 EPS of $1.48/share.
- We downgraded TER to a 3-Sector Underperform on Sept 16, 2004 due to its relatively expensive P/E valuation. TER's unchanged target P/E multiple on 2006 EPS of 18x yields a one-year target of $29/share.

Qtly EPS (Basic) ($)	Q1	Q2	Q3	Q4	Year	P/E
2003A	0.62 A	0.14 A	0.03 A	0.49 A	1.28	18.73
2004A	0.65 A	0.17 A	0.10 A	0.51 A	1.43	19.38
2005E	0.68	0.18	0.05	0.58	1.48	19.82
2006E	0.72	0.19	0.06	0.61	1.58	18.57

(FY-Dec.)	2002A	2003A	2004A	2005E	2006E
Earnings	$1.22	$1.28	$1.43	$1.48	$1.58
Cash Flow	$2.75	$2.75	$2.90	$2.97	$3.14
Price/Earnings	15.6	18.7	19.4	19.8	18.6
Relative P/E	0.4	1.0	1.0	1.1	1.0
Revenues	$1707	$1877	$1957	$2068	$2126
EBITDA	$452	$504	$520	$551	$584
Current Ratio	0.6	0.6	0.5	0.6	0.6
EBITDA/Int. Exp	2.8	2.9	3.1	3.2	3.2

I/B/E/S Estimates	**BVPS**	$14.17	**Shares O/S (M)**	105.0
EPS 2005E: $1.51	**ROE**	10.7%	**Float O/S (M)**	105.0
EPS 2006E: N/A			**Total Value ($M)**	3,081
			Float Value ($M)	3,081
Next Reporting Date	May-05		**TSX Weight**	-
Credit Ratings	S&P: BBB/Stable			

Historical price multiple calculations use FYE prices. Source: Reuters; Company reports; Scotia Capital estimates.

Pertinent Revisions

	New	Old
EPS05E	$1.48	$1.50
EPS06E	$1.58	$1.60

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For important disclosure information see Appendix A of this report.

Valuation

- **Shaved 2005-06 EPS forecasts, Targets unchanged:** We reduced our 2005 and 2006 EPS estimates for TER by $0.02 per share as our earlier estimates appear slightly optimistic on petroleum transportation earnings. Furthermore, expected low forecast 2006 interest rates will remain a headwind for gas distribution earnings and the risk that contribution from Trans Mountain may initially decline once the current Incentive Toll Settlement (ITS) expires at the end of 2005. It is modeled after ENB's five-year agreement that has expired and has an April 2005 deadline for resettlement. TER's management also guided to 6% growth in EPS (unchanged) in 2005 (from a base of $1.40 per share in 2004) and implied that growth is likely to be similar in 2006 if the Trans Mountain settlement is not unfavourable. We increased TER's target P/E multiple from 17x to 18x on February 2, 2005 when we moved up our valuation multiples for all Canadian gas and electric utilities due to faltering economic data in Canada, weak earnings outlook in Canada and continued strong inflow in dividend and income funds ($2.7B in Q4/04 and $1B in Jan 2005). We continue to value TER at a premium multiple (second only to ENB) due to a) longer-term oil pipeline growth prospects that are more certain with high crude oil prices and visible 6% plus per year organic EPS growth through at least 2005. Our one- and two-year targets are unchanged at $29 per share and $28 per share.

Q4/04 Highlights

- **Q4/04 EPS:** TER's Q4/04 earnings of $0.51 per share appeared to be clean. However, changes in recording income tax at Terasen Gas had a negative impact of about $0.06 per share that was not expected. This change has impacted all the quarterly earnings which net out on an annual basis. The quarterly dividend was increased to $0.225 per share from $0.21 per share, however, the increase came one quarter earlier than usual. The annualized divided for 2005 will be $0.90 per share compared to our forecast of $0.89 per share. Capital expenditures are expected to rise significantly to $350M in 2005 from $154M in 2004. Management expects to fund this capex via internal cash flows and subsidiary-level debt. Most of this capex will be in gas distribution ($240M) that includes $50M for putting Coastal Facilities buildings into the rate base from its present lease arrangement, the Fraser river crossing ($20M) and initial expenditures for LNG storage at Vancouver Island ($23M). The capital budget also includes $40M at Trans Mountain and $10M mainly for de-bottlenecking at Corridor.
- **Q4/04 Petroleum Transportation Strong:** Petroleum transportation earnings rose to $19.9M from $17.9M in Q4/03 despite a 2.5% decline in revenue due to lower tolls at Trans Mountain. Operating efficiencies at Trans Mountain and better contributions from Express led to the rise in earnings despite a 5% ($0.2M) YOY decline in earnings from Corridor. Trans Mountain had strong volume growth in both Canada and U.S. while volumes at Express remained flat YOY. TER management stated that Trans Mountain volumes were lower in December 2004 and remained so in Q1/05 mainly due to outages at several oil sands facilities (Shell, Suncor) and refinery turnarounds. A $2.5M decline in O&M expenses was partially offset by a $0.7M rise in depreciation. Financing costs continued to fall due to debt repayment and were down 6% and 5% in Q4/04 and 2004 respectively. TER has some foreign exchange hedges that have reduced the earnings impact of balance sheet translation. A C$0.10 swing would impact TER's income statement by only $1.1M ($0.01/share). TER is currently negotiating a new ITS with Trans Mountain shippers as the current incentive-based agreements are expiring at the end of 2005. We believe that this is a material risk to 2006 earnings.
- **Q4/04 Gas Distribution:** Gas distribution earnings were down 5% and 3% in Q4/04 and 2004 mainly due to lower allowed ROEs and earnings sharing. Customer additions remained strong during Q4/04 and total additions during 2004 were 15,983, double that of previous

years. Q4/04 natural gas sales volumes were down 6% to 41.4 PJ while 2004 volumes were also down 3% to 121.6 PJ. A drop in allowed ROE due to lower 2004 forecast interest rates and the impact of 50:50 cost efficiency sharing with customers were partly offset by organic growth and synergies of merging the Mainland and Island gas utilities. Allowed ROE's will fall further by 12 bps in 2005 to 9.03% at Terasen Gas and 9.53% at TGVI. TER has also filed a request with BCUC to consider ROE and capital structure adjustments based on the July 2004 generic EUB decision. TER's CEO estimated that a decision on this application is not likely before Q3/05.

- **Water & Utility Services and Other:** Earnings from the small water and utility services segment were up 75% to $0.7M in a seasonally weak quarter. Most of this growth is attributable to the US$30M Fairbanks Alaska water utility acquisition that started contributing effective August 1, 2004. TER has allocated $50M in its 2005 capital plan for acquisition (20%-50%) and organic growth (50%-80%) in this segment. Management stated that they were currently considering a few small acquisitions in this segment and maintained their expectation that about 33% of its 6% per year EPS growth target will come from this segment. Losses from the other activities segment increased to $9.3M from $8.8M mainly due to lower tax recovery.
- **Growth Outlook:** TER has a few growth opportunities under consideration at present.
  1. **LNG Storage:** On November 3, 2004, BC Hydro announced that Duke Point Power Energy has been selected to build a 250 MW gas-fired power project on Vancouver Island. In the Q4/04 release TER announced that BCUC had approved TER's proposed $100M LNG storage and gas compression facility subject to several conditions including a long-term transportation service agreement with BC Hydro on Feb 16, 2005. On Feb 17, 2005, BCUC approved a PPA between BC Hydro and Duke Point Power that is contingent on a natural gas procurement contract with TER, so this project looks like it is likely to go ahead. TER's board has approved $94.4M (excluding gas compression) for this project.
  2. **Express Expansion:** The 108,000 bpd Express expansion is targeted for April 2005 and is on-time and under budget ($0.05 per share EPS impact post split based on current tolling agreements). TER is also working with shippers such as Shell for the Corridor expansion.
  3. **TMX Project:** TER hopes to get expressions of interest for its TMX looping project by year-end with a possible Open Season to take place by mid-2005 as initial EOIs suggest strong shipper support. TER has capitalized approximately $4M of expenses with regard to this project in 2004 and expects to spend between $7M-12M in 2005 (all capitalized). It is proposing two options:
     - **Option 1:** A looping proposal that would transport crude to Vancouver for delivery to U.S. refineries in California.
     - Option 2: A northern leg that will transport oil sands crude to Prince Rupert for export to Asia via VLCC tankers. This is identical to ENB's Gateway Oil Pipeline proposal.

  The Canadian Association of Petroleum Producers estimated that 600,000 bpd of new pipeline capacity will be required to service incremental oil sands production over the next decade. There are various projects including TER's TMX (625,000 bpd), ENB's Gateway (400,000 bpd), TRP's Keystone pipeline (435,000 bpd), Koch's Minnesota pipeline (350,000 bpd) and Southern Access (250,000 bpd) that are competing for this incremental oil production. We believe that only one pipeline will be successful in the short-term and continue to view ENB's Gateway oil proposal as having better chances of success compared to TER's TMX looping proposal and TRP's recently announced US$1.7B Keystone oil pipeline proposal from Alberta to Illinois. Strategically, it appears to make political sense for both the Alberta and Federal Governments to support Alberta oil exports to China to keep the U.S. honest in trade matters. ENB has seeded the Chinese refinery market for several years and has a materially larger balance sheet than TER's that could tip the project in ENB's favour. There is only room for one project in the mid-term and both companies continue to point this out to investors. We believe that ENB is in advanced talks with Asian shippers like Sinopec and Petrochina for contracts on its Gateway pipeline.

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Appendix A: Important Disclosures

Company	Ticker	Disclosures*
Enbridge Inc.	ENB	H3, S
Terasen Inc.	TER	H3
TransCanada Corporation	TRP	H3, S

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* *Legend*

H 3 The Head of Equity Research/Supervisory Analyst, in his/her own account or in a related account, owns securities of this issuer.

S Scotia Capital Inc. and its affiliates collectively beneficially own in excess of 1% of one or more classes of the issued and outstanding equity securities of this issuer.

Definition of Scotia Capital Equity Research Ratings & Risk Rankings

We have a three-tiered rating system, with ratings of 1-Sector Outperform, 2-Sector Perform, and 3-Sector Underperform. Each analyst assigns a rating that is relative to his or her coverage universe.

Our risk ranking system provides transparency as to the underlying financial and operational risk of each stock covered. Statistical and judgmental factors considered are: historical financial results, share price volatility, liquidity of the shares, credit ratings, analyst forecasts, consistency and predictability of earnings, EPS growth, dividends, cash flow from operations, and strength of balance sheet. The Director of Research and the Supervisory Analyst jointly make the final determination of all risk rankings.

Ratings

1-Sector Outperform
The stock is expected to outperform the average total return of the analyst's coverage universe by sector over the next 12 months.

2-Sector Perform
The stock is expected to perform approximately in line with the average total return of the analyst's coverage universe by sector over the next 12 months.

3-Sector Underperform
The stock is expected to underperform the average total return of the analyst's coverage universe by sector over the next 12 months.

Other Ratings
Tender – Investors are guided to tender to the terms of the takeover offer.

Under Review – The rating has been temporarily placed under review, until sufficient information has been received and assessed by the analyst.

Risk Rankings

Low
Low financial and operational risk, high predictability of financial results, low stock volatility.

Medium
Moderate financial and operational risk, moderate predictability of financial results, moderate stock volatility.

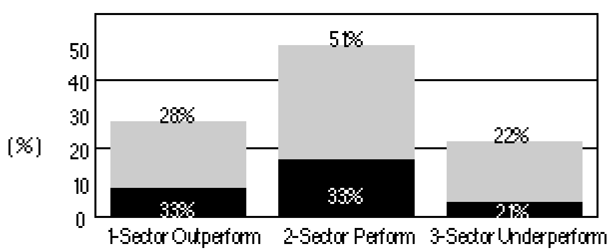
High
High financial and/or operational risk, low predictability of financial results, high stock volatility.

Caution Warranted
Exceptionally high financial and/or operational risk, exceptionally low predictability of financial results, exceptionally high stock volatility. For risk-tolerant investors only.

Venture
Risk and return consistent with Venture Capital. For risk-tolerant investors only.

Scotia Capital Equity Research Ratings Distribution*

Distribution by Ratings and Equity and Equity-Related Financings*



- Percentage of companies covered by Scotia Capital Equity Research within each rating category.
- Percentage of companies within each rating category for which Scotia Capital has undertaken an underwriting liability or has provided advice for a fee within the last 12 months.

* As at January 31, 2005.

Source: Scotia Capital.

For the purposes of the ratings distribution disclosure the NASD requires members who use a ratings system with terms different than "buy," "hold/neutral" and "sell," to equate their own ratings into these categories. Our 1-Sector Outperform, 2-Sector Perform, and 3-Sector Underperform ratings are based on the criteria above, but for this purpose could be equated to buy, neutral and sell ratings, respectively.

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Equity Research DAILY Edge

Company Comment
Thursday, May 05, 2005

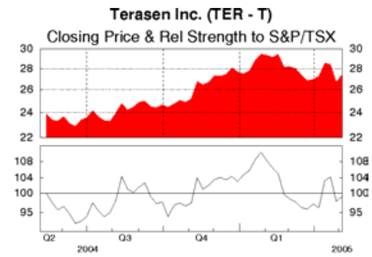
Terasen Inc.

(TER-T C$27.45)

Sam Kanes, CA, CFA – 416-863-7798
sam_kanes@scotiacapital.com

Matthew Protti, MBA – 416-863-7846
matthew_protti@scotiacapital.com

Rating: 2-Sector Perform	**Target**	1-Yr:	$29.00	**ROR**	1-Yr:	8.9%	**Est. NTM Div.**	$0.90
Risk Ranking: Low		2-Yr:	$29.00		2-Yr:	12.2%	**Div. (Current)**	$0.90
Valuation: 1-yr target based on 18x P/E on 2006E EPS							**Yield**	3.3%



Source: Global Insight, Inc.

Q1/05 EPS Temporarily Off, 2005 Still OK

Event

- TER reported Q1/05 EPS of $0.63/share that was lower than our $0.68/share estimate and the First Call Average of $0.64/share (eased from $0.66/share recently). 2006 EPS of 6% growth was unchanged.

What It Means

- We discount the temporary shortfall of $0.05/share that Trans Mountain lost due to major oil sands problems as a one time event. (Suncor plant fire, Syncrude problems).
- Earnings from gas distribution firmed $0.01/share to $0.47/share from $0.46/share even though 2005 allowed ROE fell due to cost efficiencies and strong customer growth. TER's water and utility services added $0.01/share as well and Corporate activities lost $0.03/share (a $0.02/share improvement due to mark to market gains at Clean Power).
- We decided to upgrade TER to a 2-Sector Perform as it has corrected 8% since early February on some concern of temporary throughput loss and possibly some improved prospects for Enbridge's Gateway oil pipeline export project that competes against TER's TMX project.

Qtly EPS (Basic) ($)	Q1	Q2	Q3	Q4	Year	P/E
2003A	$0.62 A	$0.14 A	$0.03 A	$0.49 A	$1.28	18.73
2004A	$0.65 A	$0.17 A	$0.10 A	$0.51 A	$1.43	19.38
2005E	$0.63 A	$0.18	$0.10	$0.58	$1.48	18.55
2006E	$0.72	$0.19	$0.06	$0.61	$1.58	17.37

(FY-Dec.)	2002A	2003A	2004A	2005E	2006E
Earnings	$1.22	$1.28	$1.43	$1.48	$1.58
Cash Flow	$2.75	$2.75	$2.90	$2.97	$3.14
Price/Earnings	15.6	18.7	19.4	18.5	17.4
Relative P/E	0.4	1.0	1.0	1.1	1.0
Revenues	$1707	$1877	$1957	$2068	$2126
EBITDA	$452	$504	$520	$551	$584
Current Ratio	0.6	0.6	0.5	0.6	0.6
EBITDA/Int. Exp	2.8	2.9	3.1	3.2	3.2

I/B/E/S Estimates	**BVPS**	$14.17	**Shares O/S (M)**	105.0
EPS 2005E: $1.49	**ROE**	10.7%	**Float O/S (M)**	105.0
EPS 2006E: $1.56			**Total Value ($M)**	2,882
			Float Value ($M)	2,882
Next Reporting Date	04-May-05		**TSX Weight**	0.30%
Credit Ratings	S&P: BBB/Stable			

Historical price multiple calculations use FYE prices. Source: Reuters; Company reports; Scotia Capital estimates.

Pertinent Revisions

	New	Old
Rating:	2-SP	3-SU
Target:		
2-Yr	$29.00	$28.00

SC Online Analyst Link

For important disclosure information see Appendix A of this report.

Valuation

- **2005-06 EPS Forecasts, Targets Unchanged:** TER's management kept its 6% growth target in EPS intact for 2005 from a base of $1.40 per share in 2004. There is some risk from Trans Mountain in 2006 regarding an Incentive Toll Settlement (ITS) that expires at the end of 2005. ENB's five-year agreement expired in April 2005 without a resettlement so TER has yet to negotiate its renewal. We increased TER's target P/E multiple from 17x to 18x on February 2, 2005 when we moved up our valuation multiples for all Canadian gas and electric utilities due to faltering economic data in Canada, weak earnings outlook in Canada and continued strong inflow into dividend and income funds. We continue to value TER at a premium multiple (second only to ENB) due to a) its longer-term oil pipeline growth prospects that are more certain with high crude oil prices and consistent track record of 6% per year organic EPS growth. Our one year target is unchanged at $29 per share but with the stock correcting towards $27 per share from just under $30 per share in February 2005, we upgraded TER to a 2-Sector Perform.

Q1/05 Highlights

- **Q1/05 EPS:** TER's Q1/05 earnings of $0.63 per share included a $0.02/share mark to market gain in its 30% go forward equity interest in Clean Energy. However, on its Q1/05 Conference call, TER management stated that its 6% 2005 EPS growth guidance excluded mark to market gains. When questioned how TER will make up the modest Q1/05 EPS shortfall in several different ways, TER's management kept coming back to tighter cost control and efficiency improvements.
- **2005 Capital Expenditures:** Capital expenditures may rise to $350M in 2005 from $154M in 2004. Management expects to fund this capex via internal cash flows and subsidiary-level debt. Most of this capex will be in regulated gas distribution ($240M) that includes $50M for putting Coastal Facilities buildings into the rate base from its present lease arrangement, the Fraser river crossing ($20M) and initial expenditures for approved LNG storage at Vancouver Island ($23M) that is going through a final appeal process next month. The capital budget also includes $40M at Trans Mountain and $10M mainly for de-bottlenecking at Corridor.
- **Q1/05 Petroleum Transportation Temporarily Weak:** Petroleum transportation earnings fell to $12.7M from $18.3M in Q1/05 due mainly to Trans Mountain losing 29% and 52% of its YOY oil throughput volume respectively on its Canadian mainline (down to 170,000 bbl/day) and U.S. mainline (down to 44,500 bbl/day). This was more of a drop than we expected and was due to the fire at Suncor, problems at Syncrude and several refinery turnarounds. Both Express and Corridor Q1/05 earnings eased just under $0.01 per share each. Express suffered a temporary volume hit as well while Corridor's 2005 allowed return fell with forecast 2005 interest rates. TER management stated that Trans Mountain oil nominations for May were at a record 400,000 bbl/day so apportionment is in effect. TER is currently negotiating the framework for a new long term operation deal with Trans Mountain shippers. The Enbridge settlement is due imminently and will set the parameters for the TER deal. In general, both Enbridge and TER have earned materially above regulated ROE levels on their oil pipeline investment under long term operating contracts due to success in managing costs and/or higher volumes. It is therefore likely that the initial year of their new agreements may be low for both companies.
- **Q1/05 Gas Distribution:** Gas distribution earnings were up $1M or $0.01 per share to $49M or $0.47 per share. A 22 basis point lower allowed ROE for 2005 (9.03%) was more than offset by strong customer additions and tag end synergies of merging the Mainland and Island gas utilities. Allowed ROE for 2005 is 9.53% at TGVI. TER has also filed a request with BCUC to consider ROE and capital structure adjustments based on the July 2004 generic EUB decision. TER's CEO estimated that a decision on this application is not likely before Q3/05.

- **Water & Utility Services and Other:** Q1/05 earnings from the small water and utility services segment were up 75% to $0.8M in a seasonally weak quarter. Most of this growth is attributable to the US$30M Fairbanks Alaska water utility acquisition that started contributing effective August 1, 2004. TER has allocated $50M in its 2005 capital plan for acquisition (20%-50%) and organic growth (50%-80%) in this segment.
- **Other Activities:** Losses from the other activities segment decreased to $2.9M from $5.1M mainly due to higher mark to market gains of $2.6M from $1.7M in Q1/05 at 30% owned Clean Energy.
- **Growth Outlook:** TER has more than a few growth opportunities under consideration at present.
    1. **LNG Storage:** The BCUC had approved TER's $100M LNG storage and gas compression facility subject to a final appeal in June 2005.
    2. **Express Expansion:** The 108,000 bbl/day Express expansion was finished on time and $10M under budget at the end of April 2005 ($0.05 per share EPS impact post split based on current tolling agreements).
    3. **Alberta Gathering Oil Line:** TER is working in an exclusive negotiation with Shell for a possible $700M oil gather pipeline expansion in Alberta.
    4. **TMX Project:** TER hopes to go to an Open Season to get firm contract for TMX 1 pumping ($570M) by mid-2005. As a stand-alone economic project, it does not appear to work but it is a pre-cursor to TMX 2 and TMX 3 stages that in total, could add 625,000 bbl/day. TER capitalized $4M of TMX expenses in 2004 and expects to spend between $7M-$12M in 2005 (all to be capitalized). It is proposing two options:
        - **Option 1:** A looping proposal that would transport crude to Vancouver for delivery to U.S. refineries in California.
        - **Option 2:** A northern leg that will transport oil sands crude to Prince Rupert for export to Asia via VLCC tankers. This is identical to ENB's Gateway Oil Pipeline proposal.

    The Canadian Association of Petroleum Producers estimated that 600,000 bbl/day of new pipeline capacity will be required to service incremental oil sands production over the next decade. There are various projects including TER's TMX (625,000 bbl/day), ENB's Gateway (400,000 bbl/day), TRP's Keystone pipeline (435,000 bbl/day), Koch's Minnesota pipeline (350,000 bbl/day) and Southern Access (250,000 bbl/day) that are competing for this incremental oil production.

    We believe that only one pipeline will be successful in the short-term and have viewed ENB's Gateway oil proposal as having better chances of success compared to TER's TMX looping proposal. TRP's recently announced US$1.7B Keystone oil pipeline proposal from Alberta to Illinois also initially appeared to be too little too late.

    Strategically, it appears to make political sense for the Alberta, B.C. and Federal Governments to support Alberta oil exports to China to help keep the U.S. honest in trade matters. ENB has a Memorandum of Understanding for 50% of its proposed capacity from PetroChina. Our confidence in ENB's Gateway pipeline prospects improved materially after seeing PetroChina in Beijing on the Scotia Capital China tour in 2004.

    Suncor's View of TMX: We can speculate all we want on which project will win but companies like Suncor that are adding up to 300,000 bbl/day to its existing 250,000 bbl/day of Alberta oil sand capacity by 2012 may have a different view. We listened to Rick George, CEO of Suncor who presented at a Scotia Capital Luncheon on Wednesday May 3, 2005. His thoughts are:

1) **Gateway was handicapped at only 10% by Suncor in May 2004.** Mr. George raised that handicap to 50/50 recently based on Enbridge's success to date with PetroChina on preliminary terms to take 50% of the throughput.

2) He initially thought that TransCanada's Keystone project had no chance but Suncor's marketing people have convinced him that this alternative route has some merit and should be looked at further.

3) He initially thought that Trans Mountain's TMX looping project that can be done in stages had the most logical and highest probability of success but points 1 and 2 negate that somewhat lately.

4) When asked what would make him get excited about aggressively participating on Enbridge's Gateway project, **Mr. George stated that if China committed to paying WTI plus prices for equivalent Alberta crude and put up $1B-$2B of firm commitments for Gateway, he would get excited in supplying it.** This of course, would negate his interest in TMX until later in the decade or into the next decade. Therefore, to speculate on Enbridge's prospects over Terasen's, one has to take a view on China's desire to commit to Alberta oil sands crude with billions and not words to satisfy Alberta oil sand producers that they are serious. **After watching China's growth in oil imports to 3M bbl/day from nothing in 5 years with forecasts as wild as 20M bbl/day of imports in 20 years, we suggest China had better hurry and commit prior to Terasen's Open Season for TMX 1 if it wants any significant Alberta crude by 2010. Our speculative sense from Enbridge is that they will commit.**

SC Online Analyst Link

Appendix A: Important Disclosures

Company	Ticker	Disclosures*
Enbridge Inc.	ENB	H3, S
Terasen Inc.	TER	H3
TransCanada Corporation	TRP	H3, S

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Moderate financial and operational risk, moderate predictability of financial results, moderate stock volatility.

High
High financial and/or operational risk, low predictability of financial results, high stock volatility.

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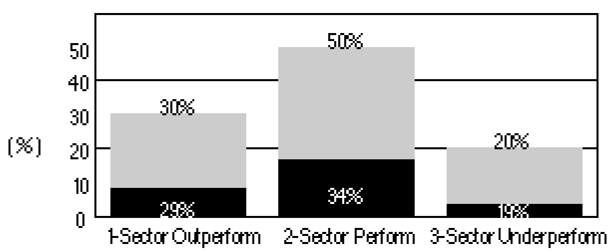
Scotia Capital Equity Research Ratings Distribution*

Distribution by Ratings and Equity and Equity-Related Financings*



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* As at April 29, 2005.

Source: Scotia Capital.

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Equity Research
DAILY Edge

Company Comment
Friday, May 20, 2005

Terasen Inc.

(TER-T C$27.20)

Sam Kanes, CA, CFA - 416-863-7798
sam_kanes@scotiacapital.com

Matthew Protti, MBA - 416-863-7846
matthew_protti@scotiacapital.com

Rating: 2-Sector Perform	**Target**	1-Yr:	$29.00	**ROR**	1-Yr:	9.9%	**Est. NTM Div.**	$0.90
Risk Ranking: Low		2-Yr:	$29.00		2-Yr:	13.2%	**Div. (Current)**	$0.90
Valuation: 1-yr target based on 18x P/E on 2006E EPS							**Yield**	3.3%

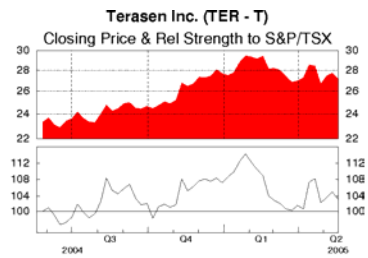
Terasen Presentation

Event

- Terasen (TER) presented at Scotia Capital's Spring Issuer's Bond Conference on May 19, 2005 where management updated bond investors on its prospects and credit quality features.

What It Means

- TER stated that it uses the exact same presentation for both equity and debt audiences. Beside its more obvious oil pipeline growth opportunities, TER spent some time explaining its water and sewer activities as well as the status of B.C. LNG and thoughts of possible acquisition of certain assets if Duke Energy becomes a seller.
- We recently upgraded TER to a 2-Sector Perform on an 8% stock price correction from peak and less certainty that Enbridge wins the next major oil pipeline expansion (Gateway) over TER's TMX due to possible native issues that emanate from Mackenzie Valley.



Source: Global Insight, Inc.

Qtly EPS (Basic)	Q1	Q2	Q3	Q4	Year	P/E
2003A	$0.62 A	$0.14 A	$0.03 A	$0.49 A	$1.28	18.73
2004A	$0.65 A	$0.17 A	$0.10 A	$0.51 A	$1.43	19.38
2005E	$0.63 A	$0.18	$0.10	$0.58	$1.48	18.38
2006E	$0.72	$0.19	$0.06	$0.61	$1.58	17.22

(FY-Dec.)	2002A	2003A	2004A	2005E	2006E
Earnings/Share	$1.22	$1.28	$1.43	$1.48	$1.58
Cash Flow/Share	$2.75	$2.75	$2.90	$2.97	$3.14
Price/Earnings	15.6	18.7	19.4	18.4	17.2
Relative P/E	0.4	1.0	1.0	1.1	1.0
Revenues	$1707	$1877	$1957	$2068	$2126
EBITDA	$452	$504	$520	$551	$584
Current Ratio	0.6	0.6	0.5	0.6	0.6
EBITDA/Int. Exp	2.8	2.9	3.1	3.2	3.2

SC Online Analyst Link

I/B/E/S Estimates	**BVPS**	$14.17	**Shares O/S (M)**	105.0
EPS 2005E: $1.49	**ROE**	10.7%	**Float O/S (M)**	105.0
EPS 2006E: $1.57			**Total Value ($M)**	2,856
			Float Value ($M)	2,856
Next Reporting Date	Jul-05		**TSX Weight**	0.30%
Credit Ratings	S&P: BBB/Stable			

Historical price multiple calculations use FYE prices. Source: Reuters; Company reports; Scotia Capital estimates.

For important disclosure information see Appendix A of this report.

Presentation Highlights

- **Growth Outlook:** Terasen (TER) presented at Scotia Capital's Spring Issuer's Bond Conference on May 19, 2005. TER's annual EPS growth target of 6% was reiterated. It has realized 8.1% annual average EPS growth since 1999. TER mentioned the status of several major growth prospects that have been known for a while:
  1. **LNG Storage:** The BCUC has approved TER's $150M LNG storage and gas compression facility on Vancouver Island subject to a fourth and final leave to appeal that should be concluded one way or another in June 2005. TER's LNG tank project would freeze natural gas for injection in summer months and withdraw gas for peak shipping demand in winter months.
  2. **Alberta Gathering Oil Line:** TER is currently working on a negotiation with Shell for a possible $700M - $800M oil gathering pipeline expansion in Alberta. This 110,000 bbl/day pipeline project was described by TER as Phase 2 of the Corridor Expansion/Bison project. TER stated that it would continue negotiations with Shell into early 2006 while also looking for third party shipper opportunities to augment the project. Tentative in-service date is 2009.
  3. **TMX Project Open Season:** TER hopes to go to an open season to get firm contracts for the TMX 1 pumping expansion and anchor loop project by mid-2005. During this open season TER would also be looking for commitments by shippers for the base load for the entire TMX expansion project. TER indicated that the pumping station expansion on Trans Mountain would cost $205M and add 35,000 bbls/day in 2006 while the anchor loop project would cost $365M for an additional 40,000 bbls/day capacity in 2008. TER would then have to assess:
     - **TMX Option 1:** A looping proposal that would transport crude to Vancouver for delivery to U.S. refineries in California or to Asia through small (550,000 bbls per ship) tankers. TER's estimated cost is $2.3B for 550,000 bbls/day.
     - **TMX Option 2:** A northern leg that will transport oil sands crude to Prince Rupert for export to Asia via VLCC tankers (1M+ bbls per ship). This is similar to ENB's Gateway oil pipeline proposal. TER's estimated cost is $2.6B for 550,000 bbls/day.

     The Canadian Association of Petroleum Producers estimated that 600,000 bbl/day of new pipeline capacity will be required to service incremental Alberta oil sands production over the next decade while TER estimates 800,000 bbl/day.
  4. **Water and Utility Service:** TER management spoke about its expansion potential in water and utility services and explained the four fragmented services it offers: 1) sell plumbing products, 2) operate water and sewer systems (90 utility systems to date in over 50 communities around North America), 3) operate a blend of utilities including water and 4) outsource services via 30% owned CustomerWorks like billing, meter reading etc. Management continues to see small (~$25M) acquisition potential in this area, where regulated returns are slightly higher than what TER achieves from a regulated gas utility rate.
     - **Whistler Utility Infrastructure Project (New):** TER is working with the municipality of Whistler to develop a hybrid gas/ground source heat pump (GSHP) utility for the town prior to the 2010 Olympics. It would include a $35M gas pipeline from Squamish to Whistler to replace the existing propane bases system there.
  5. **Inland Pacific Connector:** TER still believes that its $300 to $500M Inland Pacific Connector gas transmission line project connecting its Southern Crossing Pipeline to the Lower Mainland and Sumas area has merit but no further progress was announced. TER said this line would require major third party support with other utilities in the Pacific Northwest.

- **TER Financial Objectives**: TER reiterated its 6% per year EPS growth guidance while maintaining a strong balance sheet that would allow for low cost of capital acquisition and investment opportunities. When asked about the potential for an acquisition of some of the Duke/Westcoast assets if they became available in B.C. and/or Ontario, TER said its was a "natural acquirer" for those assets should the opportunity arise, particularly the T South gas pipeline in B.C. as TER has contracts for 40% of that transmission line's capacity. TER said it would likely be going to the equity market in late 2007 or 2008 assuming the above growth prospects go forward. TER stated that if partners become involved in the list of projects presented (possible) then equity may not be required.

Valuation

- **2005-06 EPS Forecasts, Targets Unchanged:** TER’s 6% EPS growth target is based on a $1.40 per share normalized 2004 level. There remains some risk that Trans Mountain's earnings fall significantly in 2006 at the beginning of a new 5 year Incentive Toll Settlement (ITS) that expires at the end of 2005. ENB’s five-year agreement expired in April 2005 without a resettlement so TER has yet to negotiate its renewal. ENB stated on its Q1/05 EPS conference call that is took an undisclosed provision against its Q1/05 EPS for a likely lower initial return. Both ENB and TER have at times, earned ROE's on their oil pipeline assets that approached 15% over the past several years from their 5 year incentive tolling arrangements.
- We use an 18x P/E for TER to establish our $29 per share one year target. This is a premium multiple (second only to ENB at 20x) due to a) TER's longer-term oil pipeline growth prospects that are more certain with high crude oil prices and oil sands developments and b) consistent track record of 6% plus per year organic EPS growth. We value ENB at 20x due to a consistent historical EPS growth rate of closer to 10% per year with a superior balance sheet, a more global footprint of energy infrastructure assets, greater liquidity and a New York listing.

SC Online Analyst Link

Appendix A: Important Disclosures

Company	Ticker	Disclosures*
Enbridge Inc.	ENB	H3, S
Terasen Inc.	TER	H3
TransCanada Corporation	TRP	H3, S

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Our risk ranking system provides transparency as to the underlying financial and operational risk of each stock covered. Statistical and judgmental factors considered are: historical financial results, share price volatility, liquidity of the shares, credit ratings, analyst forecasts, consistency and predictability of earnings, EPS growth, dividends, cash flow from operations, and strength of balance sheet. The Director of Research and the Supervisory Analyst jointly make the final determination of all risk rankings.

Ratings

1-Sector Outperform
The stock is expected to outperform the average total return of the analyst's coverage universe by sector over the next 12 months.

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The stock is expected to perform approximately in line with the average total return of the analyst's coverage universe by sector over the next 12 months.

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The stock is expected to underperform the average total return of the analyst's coverage universe by sector over the next 12 months.

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Under Review – The rating has been temporarily placed under review, until sufficient information has been received and assessed by the analyst.

Risk Rankings

Low
Low financial and operational risk, high predictability of financial results, low stock volatility.

Medium
Moderate financial and operational risk, moderate predictability of financial results, moderate stock volatility.

High
High financial and/or operational risk, low predictability of financial results, high stock volatility.

Caution Warranted
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Venture
Risk and return consistent with Venture Capital. For risk-tolerant investors only.

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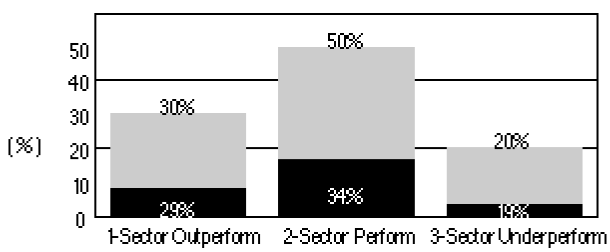
Distribution by Ratings and Equity and Equity-Related Financings*



- Percentage of companies covered by Scotia Capital Equity Research within each rating category.
- Percentage of companies within each rating category for which Scotia Capital has undertaken an underwriting liability or has provided advice for a fee within the last 12 months.

* As at April 29, 2005.

Source: Scotia Capital.

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Buy. Debt levels remain the principal knock in the credit markets against **Terasen Inc. (A(low)/ BBB-(pi)/ A3)** and its operating subsidiaries. The very thin deemed equity capitalization of its regulated gas distribution operations is the main driver of consolidated leverage. This leverage translates into weak credit ratios, with FFO interest coverage of just 2.8x in 2004, and only moderate prospects for improvement. Leverage appears to be the principal reason for the lowly "public information only" rating from S&P, which we think is far too conservative, but which we also acknowledge is unlikely to change. Apart from leverage, however, we see much to like in Terasen's businesses. All of its operating units exhibit very good stability of earnings, which is crucial to managing with leverage. Diversification is increasingly broad, with 2004 earnings split 56% from gas distribution, 40% from petroleum transportation, and 5% from water utility services. Compared to peers Enbridge and TransCanada PipeLines, we think Terasen's event risk is slightly lower, as we see Terasen management as less aggressive with acquisitions, and Terasen has a much lower likelihood of major participation in the big-ticket Alaska or Mackenzie Valley gas pipeline construction projects. Even if the big TMX project proceeds, it has distinct stages, and thus in our view less risk, than a one-shot line from Alberta to the West Coast of B.C. We see Terasen management's 6% earnings growth target as achievable with low-risk, incremental growth. In our judgement, these credit-positive features of Terasen compensate for most of its leverage handicap, and the roughly 10 bps of spread pickup over its peers make it, in our view, good value, in the context of today's expensive corporate market.

Gas Distribution

Terasen's current thrust in the gas distribution business is towards achieving operational efficiency gains. In particular, the company has already declared progress on "…improved operating efficiencies … through the ongoing integration of Terasen Gas and Terasen Gas Vancouver Island." This initiative brings to our mind a Toronto operations centre facilities tour staged in 2003 by sectoral peer Enbridge Gas Distribution, which left us very favourably impressed. The tour demonstrated what we see as solid, practical potential for operational efficiency gains in the gas distribution sector, opened up by the innovative application of modern information and communications technology, as well as other technical innovations. We believe similar applications are available to Terasen Gas Inc. and Terasen Gas Vancouver Island Inc. (TGVI), beyond the more direct synergies available on operational amalgamation of the two organizations. We note that an increasing amount of the efficiency gains must be shared with consumers under the multi-year performance based regulation settlement approved for 2004-2008 by the BCUC. The risk that efficiency gains could fail to meet targets, thereby lowering ROEs and interest coverage ratios, is a risk we take seriously, and it has been mentioned most recently by DBRS in its report on Terasen Gas this week. However, we think this risk is tempered by the ability to use technology to drive productivity in the sector.

TGVI has for some time pursued a project to increase natural gas capacity on Vancouver Island. TGVI's current proposal is for a compression facility with an adjacent LNG storage facility, with up to 1 billion cubic feet storage capacity. This would allow storage of gas shipped to the island during the off-peak season, and allow more efficient use of existing pipeline transmission capacity to the island. In February, the British Columbia Utilities Commission gave conditional approval to the LNG facility. The conditions included signing a long-term transportation service agreement with BC Hydro. BC Hydro, in turn, was to be the offtaker of the proposed Duke Point gas-fired power plant on Vancouver Island. Last week, BC Hydro abandoned the Duke Point project, as legal impediments achieved by the opposition of environmental activist groups had introduced delays that jeopardized the project's targeted 2007-2008 availability date. At present, it appears that the cancellation of Duke Point will delay TGVI's proposed LNG facility, perhaps by one to three years. TGVI will thus have a scaled-back capex program over the next few years, though some amounts (we believe less than $50 million) will probably be spent to allow the island's existing natural gas-fired electricity generation plant to shift towards base load operation (from peaking operation), to help meet electricity demand prior to BC Hydro's installation of a new electric transmission cable, probably in 2008. Part of BC Hydro's back-up plan to ensure electric system reliability on the Island until the new transmission cable is operative may include curtailment of industrial loads, though we understand that this curtailment will probably not stimulate near-term natural gas demand. Terasen believes that the LNG facility remains desirable to meet medium-term demand for natural gas on Vancouver Island, and we think the company will approach the regulator with a similar storage facility proposal at some future date.

Petroleum Transportation

Terasen has a one-third share in the Express pipeline, and is the operating partner. The Express expansion was completed on time, and a little under budget, in April, representing a capacity increase (on Express) of over

60%. The capital cost was about US$100 million, and was entirely debt financed through the $110 million US market debt issue last July. The earnings impact should be evident in Q2 results, and should annualize to about $5 million, or a 3% increase in Terasen's consolidated earnings. Express earnings are sensitive to changes in throughput, subject to a floor provided by ship-or-pay contracts for most of its capacity. Q1 throughputs on Express were weak, affected by temporary interruptions in Albertan oil sands production, notably at Suncor, though Q2 should show improvement.

The Trans-Mountain pipeline also saw lower volumes in Q1 due to Alberta production outages, but should also rebound in Q2. The Corridor pipeline is contracted (primarily to Shell Canada) on a ship-or-pay basis, and its earnings are not sensitive to throughput. Terasen continues to work with Shell towards a capacity expansion of Corridor from the current 155,000 bpd, which would occur in stages. The first of these, already approved by shippers, is a simple pumping capacity upgrade, good for an incremental 35,000 bpd for only $6.5 million. The second is a much larger expansion, for roughly $800 to $900 million. It is as yet unapproved, but could be available for service as soon as 2009.

Terasen management continues development work on the TMX proposal. Should Enbridge's Gateway proposal prevail, we would not view the "loss" as negative for Terasen credit quality. Nonetheless, we continue to think the staged nature of TMX probably makes it a less risky project from a credit perspective than a single-stage Edmonton to West Coast B.C. alternative (subject, of course, to financing, contracting, and other details).

Water

Terasen's water segment's second and third quarters (the strongest quarters seasonally) should see materially higher earnings this year, reflecting the inclusion of the Fairbanks, Alaska water utility's results. The Fairbanks acquisition, for US$30 million, closed on August 1, 2004. Management expects about one-third of Terasen's targeted average 6% future earnings growth will come from water utilities. We continue to think that the acquisition of assets in the sector is at present politically contentious among some interest groups in Canada, and even in the U.S. Nonetheless, we also think that Terasen should be able to appeal to some municipal councils by offering efficient, effective, consistently high-quality facility management, and thus expand its business gradually, with fairly small, low-risk capital or operating contracts, or acquisitions. Terasen has allocated up to $50 million of its capital plan for 2005 to the sector, though the availability and attractiveness of opportunities will always be hard to predict, and we anticipate "lumpy" growth for the segment. We note EPCOR's valuable water utility business (which contributed 27% of 2004 earnings), and we continue to view the water business line as a very attractive, diversifying complement to Terasen's gas distribution and petroleum transportation core business lines.

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Scotia Capital

Equity Research

DAILY Edge

Company Comment

Friday, July 29, 2005

Terasen Inc.

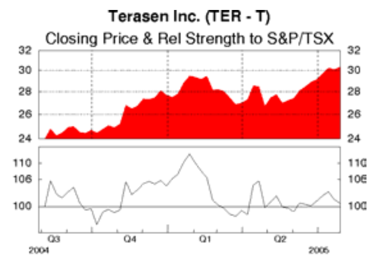
(TER-T C$31.64)

Sam Kanes, CA, CFA - 416-863-7798
sam_kanes@scotiacapital.com

Matthew Protti, MBA - 416-863-7846
matthew_protti@scotiacapital.com

Rating: 2-Sector Perform	**Target**	1-Yr:	$32.00	**ROR**	1-Yr:	4.0%	**Est. NTM Div.**	$0.90
Risk Ranking: Low		2-Yr:	$33.00		2-Yr:	10.0%	**Div. (Current)**	$0.90
Valuation: 1-yr target based on 19x P/E on averaged 2006E 2007E EPS							**Yield**	2.8%

Higher Q2/05 EPS and 2006 EPS



Source: Global Insight, Inc.

Event

- TER reported Q2/05 EPS of $0.28/share that was higher than our $0.18/share estimate and the First Call Average of $0.21/share as Trans Mountain ran at 100% of capacity, the Express expansion added more than expected, and non-recurring mark to market gains continued.

What It Means

- We discounted the temporary Q1/05 shortfall at Trans Mountain due to oil sands problems at Suncor and Syncrude and were surprised Trans Mountain ran full in Q2/05 since Suncor was short 90,000bpd.
- Earnings from gas distribution firmed $0.02/share on strong customer growth and cost efficiencies but half was simply deferred. Stronger Water and utility services results added $0.01/share while non-recurring mark to market gains at 40% owned Clean Power added $0.03/share.
- The bigger positive surprise was an extra $4M/year of tax related benefits from the Express Pipeline expansion ($0.02/share taken in Q2/05) that are viewed as "permanent".

Qtly EPS (Basic)	Q1	Q2	Q3	Q4	Year	P/E
2004A	$0.65 A	$0.17 A	$0.10 A	$0.51 A	$1.43	19.38
2005E	$0.63 A	$0.28 A	$0.10	$0.53	$1.54	20.55
2006E	$0.74	$0.20	$0.07	$0.62	$1.63	19.41
2007E	$0.77	$0.22	$0.09	$0.65	$1.73	18.29

(FY-Dec.)	2003A	2004A	2005E	2006E	2007E
Earnings/Share	$1.28	$1.43	$1.54	$1.63	$1.73
Cash Flow/Share	$2.75	$2.90	$3.03	$3.20	$3.30
Price/Earnings	18.7	19.4	20.5	19.4	18.3
Relative P/E	1.0	1.0	1.1	1.0	0.9
Revenues	$1877	$1957	$2077	$2134	$2155
EBITDA	$504	$520	$560	$592	$608
Current Ratio	0.6	0.5	0.6	0.6	0.6
EBITDA/Int. Exp	2.9	3.1	3.3	3.3	3.4

I/B/E/S Estimates	**BVPS**	$14.22	**Shares O/S (M)**	105.0
EPS 2005E: $1.49	**ROE**	11.1%	**Float O/S (M)**	105.0
EPS 2006E: $1.56			**Total Value ($M)**	3,322
			Float Value ($M)	3,322
Next Reporting Date	03-Nov-05		**TSX Weight**	0.31%
Credit Ratings	S&P: BBB/Stable			

Historical price multiple calculations use FYE prices. Source: Reuters; Company reports; Scotia Capital estimates.

Pertinent Revisions

	New	Old
Target:		
1-Yr	$32.00	$30.00
2-Yr	$33.00	$30.00
EPS05E	$1.54	$1.48
EPS06E	$1.63	$1.58
EPS07E	$1.73	$1.68

New Valuation:
1-yr target based on 19x P/E on averaged 2006E 2007E EPS

Old Valuation:
1-yr target based on 18.5x P/E on averaged 2006E 2007E EPS

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For important disclosure information see Appendix A of this report.

Valuation

- **2005 EPS Forecast Unchanged, 2006-07 $0.05 per share Higher:** TER's management kept its 6% growth target in EPS intact for 2005 from a 2004 base of $1.40 per share adding that several small acquisition in the water business in Q3/5 are still required to make its 6% target and that mark to market gains are not part of the target. **However, 2006 and forward EPS will rise a "permanent" $0.04 per share due to better than expected results from the Express Pipeline expansion than previously estimated.** We also awarded $0.01 per share more for TER's water business that is growing better than expected. There is still some risk from Trans Mountain to 2006 EPS regarding its new 5 year Incentive Toll Settlement (ITS) but management appeared satisfied that good progress is being made now that Enbridge signed its 5 year CAPP agreement. We last increased TER's target P/E multiple from 18x to 18.5x on July 7, 2005 instead of 1x for all Alberta based utilities including Enbridge due to the strength of Alberta's economy at $60/bbl oil, lower than expected interest rates (4.2% 10 year Canada forecast) non-existent inflation in Canada, negative retail sales in May 2005 and record funds flow into dividend and income funds.
- **Raise P/E by 0.5x:** Given TER's increasingly likely success on several oil pipeline projects with a) the upgrade in CAPP's Canadian oil production and imminent Shell Corridor prospects, we are adding 0.5x to TER's P/E to 19x. Our one year target at 19x on $0.05 per share higher 2006-07 EPS adds $2 per share so our new 1 year target is $32 per share, up from $30 per share. The stock market instantly reacted to the Q2/05 EPS release and added $1.40 per share to TER's stock price so we maintain our 2-Sector Perform rating.

Q2/05 Highlights

- **Q2/05 EPS:** TER's Q2/05 earnings of $0.28 per share beat our $0.18 per share and the First Call Average of $0.21 per share. The number included 1) a $0.04 per share non-recurring mark to market gain at its 40.4% equity interest in Clean Energy, 2) $0.01 per share for Q1/05 taken in Q2/05 from the higher tax related Express earnings of $1M per quarter and 3) $0.01 per share of deferred maintenance. The rest was mildly better than expected water and utility services contribution on a 30% revenue increase and the Trans Mountain pipeline system running flat out in Q2/05 versus our view that it would not. TER's line is volume sensitive under its expiring 5 year agreement with CAPP while Enbridge's previous 5 year agreement was not volume sensitive to the downside.
- **2005 Capital Expenditures Unchanged:** Capital expenditures may rise to $325M in 2005 from $154M in 2004. Management expects to fund this capex via internal cash flows and subsidiary-level debt. Most of this capex will be in regulated gas distribution ($240M) that includes $50M for putting Coastal Facilities buildings into the rate base from its present lease arrangement, the Fraser river crossing ($20M) and includes $40M at Trans Mountain and $10M mainly for de-bottlenecking at Corridor. TER's capital structure is currently about 66% debt to total capitalization so any major incremental project will likely require equity.
- **Q2/05 Petroleum Transportation:** Q2/05 petroleum transportation earnings increased YOY to $20.9M from $16.2M in Q2/04 due mainly to the Trans Mountain pipeline running full again after losing Q1/05 oil sands production from the Suncor fire and Syncrude problems. TER did not elaborate on its $1M/quarter of permanent or near permanent tax structuring benefits from its non-taxable partners ($1M per quarter for the foreseeable future, $2M taken in Q2/05 for Q1/05 catch-up) from the Express expansion starting up in April 2005.Express Q2/05 earnings therefore increased to $0.07 per share from $0.03 per share in Q2/04. Corridor Q2/05 earnings were flat YOY at $0.04 per share.
    - TER is currently negotiating the framework for a new long term operation deal with Trans Mountain shippers, which will likely be impacted by Enbridge's (ENB) new Incentive Tolling Settlement (ITS). TER stated that there is good progress on the ITS now that ENB has settled and TER's ITS is expected to be completed by the end of 2005.

- **Q3/05 EPS**: TER stated on the conference call that in Q3/05 there was a small spill on a Trans Mountain pipeline lateral which caused 600 bbls to leak that may cost $0.5M and $1M. TER also noted that due to a customer's plant problem in Edmonton, July throughput on Trans Mountain was down to 200,000 bbls/day from 242,000 bbls/day in Q2/05. However, in August, the pipeline system was on apportionment again.

- **Q2/05 Gas Distribution:** Q2/05 Gas distribution earnings were up $2.6M or $0.02 per share to $0.07 per share from $0.05 per share in Q2/04. A 22 basis point lower allowed ROE for 2005 (9.03%) was more than offset by strong customer growth and remaining operating efficiencies of merging the Mainland and Island gas utilities. Allowed ROE for 2005 is 9.53% at TGVI.
- **Water & Utility Services and Other:** Q2/05 earnings from the small water and utility services segment were up $0.01 per share or $1.2M to $3.8M or $0.03 per share from $2.6M in Q2/04. Most of this growth is from the Waterworks business which continues to capitalize on the strength in the Alberta and B.C. economies as well as increased earnings from Fairbanks Sewer and Water (acquired July 2004). TER has allocated $50M in its 2005 capital plan for acquisition (20%-50%) and organic growth (50%-80%) in this segment.
- **Other Activities:** Losses from the other activities segment decreased to $2.9M (loss of $0.02 per share) from a loss of $6.0M in Q2/04 due to higher Q2/05 mark to market gains of $3.9M up from $0.6M in Q2/04 at 40.4% owned Clean Energy.
- **Regulatory:** In Q2/05, TER filed a rate application with the BUC in which it requested a 5% increase in equity thickness (from 33% to 38% for Terasen Gas) and an increase to ROE of 1.75%. TER believes that it has a good chance of receiving these increases as gas prices have increased considerably recently relative to more stable local power prices and that the current rates are out of synch with Alberta based ROEs. We are not as optimistic on the ROE request, as it is questionable that TER's risk profile has actually increased materially. While TER may receive some amount of equity thickness increase, it would likely be required to inject more equity at the corporate level similar to what Emera experienced at its 100% owned Nova Scotia Power Inc regulated entity. TER also stated that it has filed to extend its existing TGVI settlement so that it better aligns with the requested Terasen Gas regulatory settlement.

Growth Outlook

- **TMX:** TER's growth opportunities improved in Q2 and Q3 2005. On July 12, 2005 TER filed an application with the National Energy Board (NEB) to increase the capacity of the Trans Mountain pipeline by 35,000 bbls/day from 225,000 bbls/day to 260,000 bbls/day for an estimated $210M (TMX Phase I) for Q1/07. The TMX Phase I was also included by the Canadian Association of Petroleum Producers (CAPP) in the ongoing TER ITS discussions. TER stated that the next TMX system expansion request will occur late in Q3/05 when TER will hold an open season for the $365M TMX 30 inch pipeline loop in Alberta and eastern BC (Phase II), which could lead to an eventual twinning of the entire Trans Mountain system (Phase III) that would transport crude to Vancouver for delivery to U.S. refineries in California or a northern leg into Prince Rupert that will transport oil sands crude to Prince Rupert for export to Asia via VLCC tankers. The northern leg option is identical to ENB's Gateway Oil Pipeline proposal. TMX 2 and 3 could add 625,000bbls/day.
  - **CAPP Increases Canadian Oil Production Forecast:** On July 19, 2005, CAPP raised its total Canadian crude oil production forecast from 3.6M bbls/day to 3.9M bbls/day in 2015. CAPP increased forecast 2015 conventional oil production in Western Canada by 125K bbls/day and oil sands production by 100K bbls/day from the 2004 numbers. CAPP had previously estimated that 600K bbls/day of new pipeline capacity will be required to service incremental oil sands production over the next decade. **We believe that with CAPP's latest revision, 825K bbls/day may be necessary.** There are various projects including TER’s TMX (625K bbls/day), ENB’s Gateway (400K

bbls/day), TRP's Keystone pipeline (435K bbls/day), Koch's Minnesota pipeline (350K bbls/day) and Southern Access (250K bbls/day) that are competing.

- ENB's $2.5B Gateway oil export pipeline project and $1.7B condensate import line (less $600m if built together) are claimed to be ahead of Terasen's TMX project at this time. TRP's US$1.7B Keystone oil pipeline proposal from Alberta to Illinois initially appears to be too little too late.

- **LNG Storage Delay:** The BCUC had approved TER's $100M LNG storage and gas compression facility, however in Q2/05 B.C. Hydro announced it was not going to be proceeding with the power plant on Vancouver Island that the storage facility was set up to serve. **The BCUC approval was contingent on that power plant being constructed.** TER stated that it thinks there is still a need for LNG storage on Vancouver Island and is in the process of resubmitting the application (est. Q4/05) and expects a 1-2 year delay in construction.
- **Corridor Expansion:** TER is in an exclusive negotiation with Shell for the $800M Corridor pipeline expansion in Alberta with an estimated in service date of 2009. TER stated that it is currently working on engineering and environmental plans for the 42 inch expansion from Muskeg River to Edmonton which could carry 1M bbls/day. Shell will likely have a minimum take or pay contract to guarantee TER a certain minimum return on the investment, but TER noted there would be significant capacity left for third party shippers. The benefit from allowing third party shippers will be split somehow between Shell and TER.
- **Water Operations:** TER stated that it has more opportunities to grow its water business based on its bidding in Alaska and Southern Alberta for water operations. It expects to close on a couple of small deals in Q3/05, one in B.C. and one in Alberta. The earnings lift from these deals will be small and is already included in the 6% 2005 EPS growth guidance.

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Appendix A: Important Disclosures

Company	Ticker	Disclosures*
Enbridge Inc.	ENB	H3, S
Terasen Inc.	TER	H3
TransCanada Corporation	TRP	H3, S

Each research analyst named in this report or any subsection of this report certifies that (1) the views expressed in this report in connection with securities or issuers that he or she analyzes accurately reflect his or her personal views; and (2) no part of his or her compensation was, is, or will be directly or indirectly, related to the specific recommendations or views expressed by him or her in this report.

The Research Analyst's compensation is based on various performance and market criteria and is charged as an expense to certain departments of Scotia Capital Inc., including investment banking.

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* *Legend*

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We have a three-tiered rating system, with ratings of 1-Sector Outperform, 2-Sector Perform, and 3-Sector Underperform. Each analyst assigns a rating that is relative to his or her coverage universe.

Our risk ranking system provides transparency as to the underlying financial and operational risk of each stock covered. Statistical and judgmental factors considered are: historical financial results, share price volatility, liquidity of the shares, credit ratings, analyst forecasts, consistency and predictability of earnings, EPS growth, dividends, cash flow from operations, and strength of balance sheet. The Director of Research and the Supervisory Analyst jointly make the final determination of all risk rankings.

Ratings

1-Sector Outperform
The stock is expected to outperform the average total return of the analyst's coverage universe by sector over the next 12 months.

2-Sector Perform
The stock is expected to perform approximately in line with the average total return of the analyst's coverage universe by sector over the next 12 months.

3-Sector Underperform
The stock is expected to underperform the average total return of the analyst's coverage universe by sector over the next 12 months.

Other Ratings
Tender – Investors are guided to tender to the terms of the takeover offer.

Under Review – The rating has been temporarily placed under review, until sufficient information has been received and assessed by the analyst.

Risk Rankings

Low
Low financial and operational risk, high predictability of financial results, low stock volatility.

Medium
Moderate financial and operational risk, moderate predictability of financial results, moderate stock volatility.

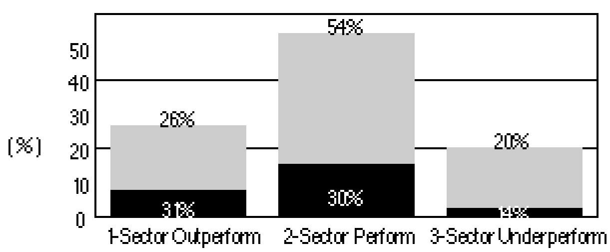
High
High financial and/or operational risk, low predictability of financial results, high stock volatility.

Caution Warranted
Exceptionally high financial and/or operational risk, exceptionally low predictability of financial results, exceptionally high stock volatility. For risk-tolerant investors only.

Venture
Risk and return consistent with Venture Capital. For risk-tolerant investors only.

Scotia Capital Equity Research Ratings Distribution*

Distribution by Ratings and Equity and Equity-Related Financings*



- Percentage of companies covered by Scotia Capital Equity Research within each rating category.
- Percentage of companies within each rating category for which Scotia Capital has undertaken an underwriting liability or has provided advice for a fee within the last 12 months.

* As at June 30, 2005.

Source: Scotia Capital.

For the purposes of the ratings distribution disclosure the NASD requires members who use a ratings system with terms different than "buy," "hold/neutral" and "sell," to equate their own ratings into these categories. Our 1-Sector Outperform, 2-Sector Perform, and 3-Sector Underperform ratings are based on the criteria above, but for this purpose could be equated to buy, neutral and sell ratings, respectively.

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Electric & Gas Utilities

Terasen Takeover Valuation Impacts Sector

Sam Kanes, CA, CFA - 416-863-7798
sam_kanes@scotiacapital.com
Matthew Protti, MBA - 416-863-7846
matthew_protti@scotiacapital.com

SC Online Analyst Link

Event

- Terasen (TER) announced on August 1, 2005 after market close that it had entered into an agreement where it may be 100% purchased by Kinder Morgan Inc. (KMI.N) with a targeted year-end close.

What It Means

- We continue to suggest TransAlta (TA), Enbridge (ENB), and ATCO (ACO.nv.x) as the best risk-reward alternatives to Terasen in Canadian Energy Utilities with Enbridge being the closest comp to TER. All three also benefit from $60/bbl plus oil in different ways: TA through higher power margins in the U.S., ENB through oil pipeline expansions like TER is pursuing and ATCO through housing/infrastructure for oil sands projects.
- California called two stage 2 power supply emergencies in July 2005 which highlights the tight California power market. Total also announced it was purchasing Deer Creek Energy which, along with the TER/KMI deal will have the effect of increasing Alberta's oil sands' visibility further.
- We increased our one- and two-year targets on all stocks in our coverage universe on July 7, 2005 due to a) $60/bbl oil that heavily favours Alberta energy utilities in Canada's highest growth and wealthiest province and b) record dividend and income funds flow that doubled YOY in May 2005.

Universe of Coverage

	Price	Rating	Risk	1-Yr	ROR	2-Yr	ROR
ACO.NV.X	C$76.00	1-SO	Med	$82.00	9.9%	$82.00	11.9%
BLX.A	C$7.70	3-SU	High	$6.85	-11.0%	$7.25	-5.8%
CU.NV	C$72.60	2-SP	Med	$76.00	7.7%	$79.00	14.9%
CUP.U	C$11.22	2-SP	Med	C$12.50	19.2%	C$13.50	35.9%
EMA	C$18.02	3-SU	Low	$18.50	7.6%	$19.00	15.3%
ENB	C$36.08	1-SO	Low	$39.00	10.9%	$39.50	15.0%
FTS	C$84.00	2-SP	Med	$82.50	0.9%	$82.50	3.6%
KHD	C$4.08	3-SU	High	$4.20	2.9%	$4.70	15.2%
TA	C$21.66	1-SO	High	$25.00	20.0%	$27.00	33.9%
TER	C$36.25	3-SU	Low	$32.00	-9.2%	$33.00	-4.0%
TRP	C$33.60	2-SP	Low	$35.50	9.3%	$37.00	17.4%

KMI/TER Transaction Details

- **Offer Valuation:** Kinder Morgan Inc. (KMI.N) will acquire 100% of the shares of Terasen Inc. (TER) for a purchase price, including debt of US$5.6B or C$6.9B. The transaction represents about 24x P/E on 2005 Terasen consensus estimate earnings and 2.6x book, smashing previous Canadian energy utility takeover records by 20%+ on both metrics. The takeover premium is 14% over Terasen's closing share price on July 29, 2005, 20% over TER's 20 day average closing price and an additional 2% for the positive reaction to KMI's stock price that rose 6% on August 2, 2005 as 35% of any increase/decrease in KMI's stock will be added to/subtracted from TER's stock. For further KMI offer details, see our August 2, 2005 TER note.
- **Westcoast/Duke 2001 Transaction:** This transaction served as a proxy to the proposed KMI-TER deal. In September, 2001 Duke offered to purchase Westcoast Energy (W) for similar stock premiums of 14.8% one day prior, 18.5% on 20 days average. The W deal size was larger at C$13B (including C$7.2B in net debt and preferred). Due to a perceived scarcity premium on Canadian pipeline companies after Duke's bid for Westcoast, we upgraded the shares of Enbridge and TransCanada on future pipeline stock scarcity value as well as BC Gas (Terasen) due to its expanding oil pipeline position in Western Canada (See Exhibit 1 for historic transaction details). While we are not raising our P/E multiples yet again although we are tempted, KMI's bid for TER at 24x P/E on current 2005 EPS is confirmation of our record high P/E multiples that we currently use on 2006-7 EPS averaged to set our one year stock targets.

Exhibit 1- Historic Regulated Asset/Company Transactions

Sellers	Asset/Company	Buyer	Date	Est. P/B Regulated Equity	Est. Share Takeover Premium
Terasen	**100% of Company**	**Kinder Morgan**	**Q4/05**	**2.6x**	**14 - 20%**
TransAlta Utilities	Alberta Transmission	OTPP/SNC Lavalin	Q2/02	1.85x	n/a
Westcoast Energy	100% of Company	Duke Energy	Q1/02	1.85x	15%
Westcoast Energy	Centra B.C	BC Gas (Terasen)	Q1/02	1.3x	n/a
TransAlta Utilities	Alberta Electricity Distribution	Utilicorp	Q1/01	1.8x	n/a
Westcoast Energy	Centra Manitoba Gas Distribution	Manitoba Hydro	Q3/99	2.1x	n/a
Westcoast Energy	Centra Alberta Gas Distribution	AltaGas	Q2/98	1.8x	n/a
British Gas	Consumers Gas	Enbridge	Q2/94	1.8x	30%
Maritime Electric	100% of Company	Fortis	Q3/94	1.4x	28%
Union Energy	100% of Company	Westcoast	Q4/92	1.5x	32%

Source: Company Reports, Scotia Capital.

What does the TER takeover mean for:

- **Enbridge (ENB):** We value ENB at a 1x-3x premium multiple over the rest of the Canadian energy utility sector at 21x for the following reasons:
  1. ENB has had the best management team in the business for the past 20 years. This is evidenced by their double digit EPS and dividend growth record and stock price performance over the past 10 years.
  2. We continue to believe that ENB wins the Gateway oil export pipeline race with Terasen although Kinder Morgan will be a formidable competitor.
  3. ENB is the owner of the best Canadian gas LDC (Toronto) that has the third best growth rate in North America behind Las Vegas and Phoenix-Scottsdale.
  4. Its balance sheet remains under-levered even after its $600M acquisition of Shell's gas pipelines in the Gulf of Mexico (60% debt to total cap, A- credit).

5. The proposed TER takeover by Kinder Morgan leaves ENB as the remaining way for major international companies to play the Canadian oil sands on the pipeline plane. ENB has exposure to the upside of the oil sands production without the same downside commodity risk as a pure-play oil sands company. In our view, ENB will continue to experience a pipeline scarcity premium going forward as it becomes more difficult to invest in either Canadian pipelines or pipelines with a focus on the Alberta oil sands. We do not believe that ENB is a takeover candidate for the likes of Duke or Warren Buffett at its premium P/E multiple.

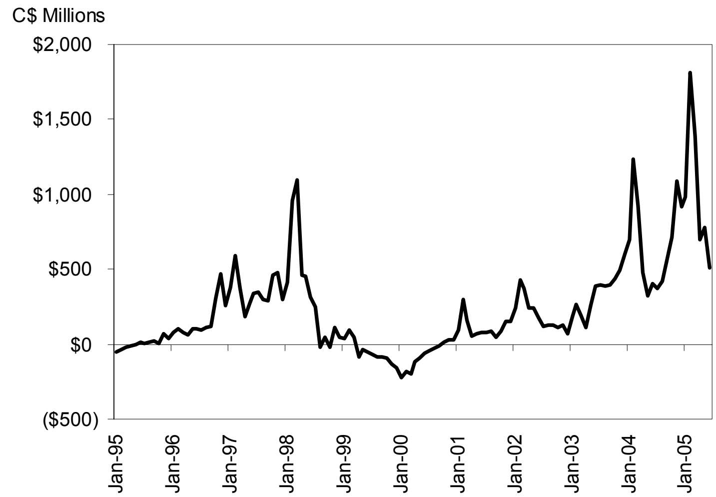
- **TransCanada (TRP):** Like ENB, TRP may benefit from the KMI deal, but somewhat less than ENB from a pipeline scarcity premium in Canada as 100% of TRP's current pipelines are gas based and do not serve the oil sands. TRP may receive some of the re-allocation of TER equity from Canadian institutional shareholders, especially since the KMI/TER transaction will not have exchangeable shares offered. In the short term, TRP's stock was buffeted a little by a poor Q2/05 EPS number due to unplanned Bruce nuclear plant outages.
- **TransAlta (TA):** Terasen's business profile is less correlated to TA, which benefits more directly from $60/bbl plus oil through higher forecast forward power contract renewals in the deregulated Pacific Northwest (PNW) U.S. power market. Higher PNW prices are TA's greatest EPS upside as its 9M MWh of contracts roll over from $30/MWh today to sharply higher levels ($50/MWh plus?) based partly on high oil and gas costs. We listened to both Duke Energy's and Calpine's conference calls on August 3, 2005. Both spoke to the sharp increase in forward contract power prices in Western U.S. markets but did not quantify them. TA estimated PNW power prices of $50-$55/MWh for 2008 base-load contracts on its Q2/05 EPS conference call. Oil over $60/bbl has meant U.S. natural gas over $8/mcf. Even at that price, Calpine announced another gas based power plant for California with GE this week to be built for 2008. It will need power prices closer to $80/MWh to make a full return at today's gas prices.
- **ATCO:** $60/bbl plus oil means more Alberta oil sand projects, particularly now that Total has also decided to enter the fray via its acquisition of an oil sands junior. ATCO's non-regulated expertise and EPS sensitivity lies in housing/sheltering large construction support facilities for major multi-year projects. ATCO has the Nexen-OPTI 2,500 person camp infrastructure contract and is pursuing the 6,000 working Horizon project for Canadian Natural Resources for 2006.
- **Alberta Based Utilities at a Premium:** We wrote at the beginning of July that the stock revaluation mania that has gripped the oil and gas sector had spilled over into the second best TSX sub-sector this year, oil and gas infrastructure utilities. This trend continues, particularly for those stocks that are Alberta based, due to $60/bbl plus oil prices and now the TER/KMI and Total/Deer Creek deals.
- **Mid-Cap Comps:** For investors that held Terasen as a mid-cap growth play, Fortis, ATCO and Canadian Utilities would be appropriate mid-cap replacements as all 3 have expected EPS growth of 5% plus per year.
- **Other Canadian Utilities:** The remaining Canadian utilities that are not related to Alberta (Emera, Caribbean Utilities) will see the least increase in value should the deal go through, due to there being one less Canadian utility in the space.

Stay Overweight Energy Utilities

- Our Overweight Energy Utilities recommendation since December 2004 was/is still predicated on:
  - **Strong C$/Weak Economic Data:** Scotia Economics' C$ forecast of US$0.90 continues albeit with a lag. This signals weaker Canadian manufacturing and current account surplus data going forward. In 1990, the last time the C$ approached US$0.90, interest sensitive stocks such as TRP outperformed the slumping S&P/TSX index by about 20%.
  - **Lower Interest Rates:** Interest rates are at 1958 levels with 10-year Canada yields at about 3.9% at present. Our 1 year forecast for 10 year Canada rates is a benign 4.2%.

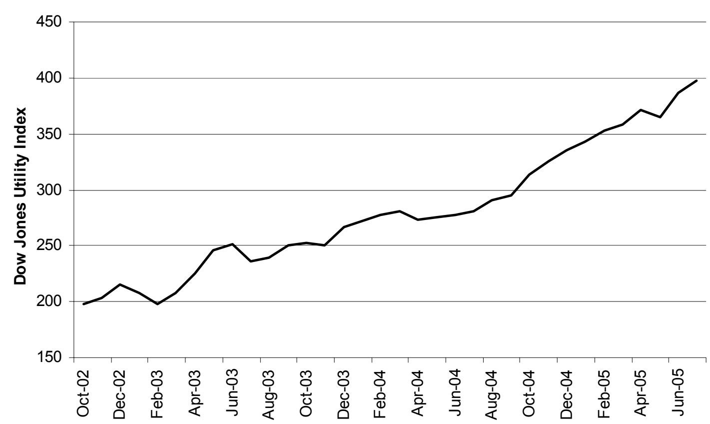
- **Outstanding Dividend and Income Funds Flow:** Funds flow into dividend and income funds remains at record levels that are about double normal levels. June 2005 dividend and income funds inflows were $508M. YTD June 2005 ($6.173B) is 52% up over YTD June 2004 (See Exhibit 2). **If it wasn't for record 2005 income trust IPO's and conversions, Canadian Energy Utility P/E multiples would be higher.**
- **Dow Jones Utilities Soaring:** The Dow Jones Utilities index has just hit 405, **up 27% from November 1, 2004** and up 100% since November 1, 2002 (See Exhibit 3). One of President Bush's major re-election promises was to maintain a reduced 15% dividend tax rate for at least another four years. The Dow Utilities trade more off after tax yield values than any other equity class, similar to Canadian energy utilities. By cutting the U.S. individual dividend tax rate to 15% from as high as 40% in some states, **President Bush effectively raised the value of high dividend paying stocks by as much as 25%!** This makes the New York Inter-listed Canadian Energy utilities (TA, ENB and TRP) more attractive to U.S. investors than any other energy utilities in Canada as U.S. inter-listed foreign stocks that pay dividends are not prejudiced by the 15% U.S. dividend tax rate.
- New is the agreed upon U.S. Energy Bill that will repeal the restrictive energy utility takeover rules in place since the 1930's in the U.S. (known as PUHCA) that President Bush will sign into law later this month. This opens the playing field to numerous takeovers that are already beginning to line up (MidAmerica-Pacificorp, Duke-Cinergy and Exelon-PSEG). This may lead to higher P/E multiples on U.S. takeover targets.

Exhibit 2 - Canadian Dividend & Income Funds - Monthly Net Sales



Source: IFIC, Scotia Capital.

Exhibit 3 - Dow Jones Utility Index



Source: Bloomberg, Scotia Capital.

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Appendix A: Important Disclosures

Company	Ticker	Disclosures*
ATCO Ltd.	ACO.NV.X	H3
Canadian Utilities Limited	CU.NV	H3, S
Emera Incorporated	EMA	H3, S
Enbridge Inc.	ENB	H3, S
Fortis Inc.	FTS	H3, S, U
Terasen Inc.	TER	H3
TransAlta Corporation	TA	H3, S
TransCanada Corporation	TRP	H3, S

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* *Legend*

H3 The Head of Equity Research/Supervisory Analyst, in his/her own account or in a related account, owns securities of this issuer.

S Scotia Capital Inc. and its affiliates collectively beneficially own in excess of 1% of one or more classes of the issued and outstanding equity securities of this issuer.

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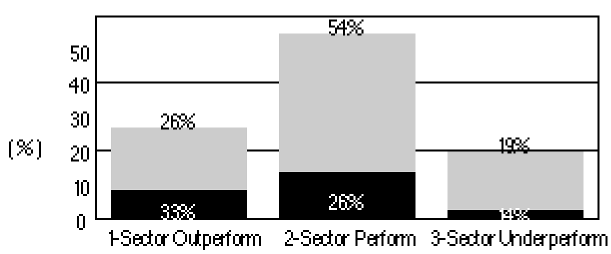
Scotia Capital Equity Research Ratings Distribution*

Distribution by Ratings and Equity and Equity-Related Financings*



* As at July 29, 2005.

Source: Scotia Capital.

- Percentage of companies covered by Scotia Capital Equity Research within each rating category.
- Percentage of companies within each rating category for which Scotia Capital has undertaken an underwriting liability or has provided advice for a fee within the last 12 months.

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Equity Research DAILY Edge

Company Comment
Wednesday, August 03, 2005

Terasen Inc.

(TER-T C$36.00)

Sam Kanes, CA, CFA - 416-863-7798
sam_kanes@scotiacapital.com

Matthew Protti, MBA - 416-863-7846
matthew_protti@scotiacapital.com

Rating: 3-Sector Underperform	**Target**	1-Yr:	$32.00	**ROR**	1-Yr:	-8.6%	**Est. NTM Div.**	$0.90
Risk Ranking: Low		2-Yr:	$33.00		2-Yr:	-3.3%	**Div. (Current)**	$0.90
Valuation: 1-yr target based on 19x P/E on averaged 2006E 2007E EPS							**Yield**	2.5%

Kinder-Morgan to Purchase TER

Event

- Terasen (TER) announced on August 1, 2005 after market close that it had entered into an agreement where it may be 100% purchased by Kinder Morgan Inc. (KMI.N) with a targeted year-end close.

What It Means

- The 14% 1 day and 20% 20 trailing day trading premium bid for TER's stock at $35.75/TER share takes us to a 3-Sector Underperform from 2-Sector Perform.
- This will over time, release most of the $3.75B 65% cash 35% Kinder equity total bid for TER's equity to mostly Canadian income oriented individuals and funds to re-deploy.
- We continue to suggest TransAlta, Enbridge, and ATCO (our 1-Sector Outperforms) as the best risk-reward alternatives in Canadian Energy Utilities with Enbridge being the closest comp to TER. All three also benefit from $60/bbl plus oil in different ways.

Source: Global Insight, Inc.

Qtly EPS (Basic)	Q1	Q2	Q3	Q4	Year	P/E
2004A	$0.65 A	$0.17 A	$0.10 A	$0.51 A	$1.43	19.38
2005E	$0.63 A	$0.28 A	$0.10	$0.53	$1.54	23.38
2006E	$0.74	$0.20	$0.07	$0.62	$1.63	22.09
2007E	$0.77	$0.22	$0.09	$0.65	$1.73	20.81

(FY-Dec.)	2003A	2004A	2005E	2006E	2007E
Earnings/Share	$1.28	$1.43	$1.54	$1.63	$1.73
Cash Flow/Share	$2.75	$2.90	$3.03	$3.20	$3.30
Price/Earnings	18.7	19.4	23.4	22.1	20.8
Relative P/E	1.0	1.0	1.2	1.2	1.1
Revenues	$1877	$1957	$2077	$2134	$2155
EBITDA	$504	$520	$560	$592	$608
Current Ratio	0.6	0.5	0.6	0.6	0.6
EBITDA/Int. Exp	2.9	3.1	3.3	3.3	3.4

I/B/E/S Estimates	**BVPS**	$14.22	**Shares O/S (M)**	105.0
EPS 2005E: $1.50	**ROE**	11.1%	**Float O/S (M)**	105.0
EPS 2006E: $1.60			**Total Value ($M)**	3,780
			Float Value ($M)	3,780
Next Reporting Date	03-Nov-05		**TSX Weight**	0.32%
Credit Ratings	S&P: BBB/Stable			

Historical price multiple calculations use FYE prices. Source: Reuters; Company reports; Scotia Capital estimates.

Pertinent Revisions

	New	Old
Rating:	3-SU	2-SP

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For important disclosure information see Appendix A of this report.

Terasen's Take-over Transaction Details

- **Offer Details:** Kinder Morgan Inc. (KMI.N) will acquire 100% of the shares of Terasen Inc. (TER) for a purchase price, including debt of US$5.6B or C$6.9B. TER's equity in the offer is valued at about $3.75B (105M at $35.75 per TER share). The agreement was unanimously approved by both companies' boards. The transaction yields a premium of 14% over Terasen's closing share price on July 29, 2005 and 20% over TER's 20 day average closing price. Since the deal is forecast to be 6%-8% EPS accretive to Kinder Morgan in year 1, its shares immediately reacted favourably, moving up as much as 10% at one point yesterday to $98.45 per share. KMI also stated that its annual $3 per share dividend is expected to rise to $3.50 per share in 2006 but did not state that the deal closing is conditional to the KMI dividend increase. TER shareholders have the choice to elect for 1) C$35.75 per share in cash, 2) 0.3331 shares of KMI per TER share or 3) C$23.25 in cash (65%) plus 0.1165 shares of KMI (35%).
- All elections to KMI's offer will be subject to pro-ration in the event total cash elections exceed 65% or share elections exceed 35%. **Therefore, TER's stock will move at 35% of the rate of the move in Kinder Morgan's stock price until the deal closes.** Non-electing shareholders will receive option 3, the 65%/35% cash/shares split. There were **no** exchangeable shares offered for Canadian shareholders. The termination fee of C$75M is 1.9% of the deal price. KMI's offer is above our 1-year target price of C$32 and represents about 23.8x 2005E consensus earnings of $1.49 per share.
- **Timeline:** Steps to deal completion include: 1) regulatory filings in Q3/05, 2) end-October 2005 TER shareholder vote (75% approval required) 3) Canadian regulatory approvals from the BCUC, Investment Canada and the Canadian Competition Act, and 4) U.S. regulatory approvals from Hart-Scott-Radino. Both companies expect the deal to close by year-end 2005.
- **Valuation:** We raised our TER valuation on July 29, 2005 given TER's increasingly likely success on several oil pipeline projects with the upgrade in CAPP's Canadian oil production and imminent Shell Corridor prospects by adding 0.5X P/E to TER's target P/E. The stock market immediately reacted to TER's Q2/05 EPS release by adding $1.40 per share to TER's stock price so we maintained our 2-Sector Perform rating. The 14% 1 day and 20% 20 trailing day trading premium bid by KMI for TER's stock at $35.75 per TER share now takes us to a 3-Sector Underperform from 2-Sector Perform.

Exhibit 1 – Combined Kinder Morgan and Terasen Metrics

Kinder Morgan Inc. (KMI.N)	(US$B)	Terasen Inc. (TER)	(US$B)
Market Equity	$11.2	Market Equity	$2.7
Debt	$2.7	Debt	$2.4
Enterprise Value	$13.9	Enterprise Value	$5.1

Pro Forma Combined Entity	(US$B)
Market Equity	$12.0
Debt	$7.2
Enterprise Value	$19.2
KMP E.V.	$15.9
E.V. Total	$35.1

Source: Company Reports, Scotia Capital.

Exhibit 2 – Combined Kinder Morgan and Terasen Operations

Kinder Morgan Operations	% of EBITDA	Terasen Operatios	% of EBITDA
Kinder Morgan Partners	50%	Retail Gas Distribution	65%
Natural Gas Pipelines	41%	Petroleum Pipelines	29%
Retail Gas Distribution	7%	Other	6%
Other	2%	2006E EBITDA	$0.5 billion
2006E EBITDA	$1.3 billion		

Pro Forma Combined Operations	% of EBITDA
Kinder Morgan Partners	36%
Natural Gas Pipelines	30%
Retail Gas Distribution	23%
Petroleum Pipelines	8%
Other	3%
2006E EBITDA	$1.8 billion

Note: EBITDA excludes corporate G&A before cost savings.

Source: Company Reports, Scotia Capital.

Developments

- **Kinder Morgan's Strategic Rationale:** KMI is a U.S. based midstream energy company (enterprise value of US$30B) based in Houston and founded by Richard Kinder, who continues on as CEO and Chairman. Mr. Kinder owns 19.68% of KMI's shares outstanding and pays himself $1 per year in salary. KMI has 35,000 miles of natural gas and product pipelines and 145 terminals. It also owns 16% and is the General Partner of Kinder Morgan Energy Partners (KMP.N), a large public pipeline master partnership. KMP also owns petroleum product pipelines, terminals, natural gas and C02 pipelines. KMI focuses on fee-based businesses where it collects fees on the transportation and storage of energy products, avoiding direct commodity price risk. On its conference call, KMI stated that the TER deal featured stable, low risk assets receiving reasonable regulated rates, giving 6% - 8% 2006 earnings accretion for KMI in the first year following the acquisition and provides "hellacious" large growth opportunities from Alberta's oil sands. TER's backlog of opportunities around crude oil export pipelines total $3B according to TER's conference call. (See Exhibits 1 and 2).
  - KMI also stated that since both companies were BBB rated, the combined company should receive a BBB rating. After the call S&P placed KMI's BBB rating on Watch Negative based on the increased leverage necessary to fund the purchase, while Moody's reaffirmed KMI's Baa2/Stable rating. Moody's placed TER's senior unsecured A3 debt on review for possible downgrade due to KMI's debt being lower rated than TER's
  - KMI's CEO said on the conference call that Canadian oil sand production growth over the next 5 - 7 years was analogous to incremental supply from an entirely new Permian basin (1M bbls/day - the largest oil basin in the U.S.). This analogy should allow U.S. investors to better correlate the size of the oil sands opportunities to a U.S. equivalent deposit. There is further room for supply increases beyond the next 1M bbls/day after 2010/12 (See CAPP discussion below).
- **Regulatory Issues:** Both KMI and TER stated on their respective conference calls that there shouldn't be any substantial regulatory issues with the deal. TER stated that it had already notified several regulatory stakeholders about the deal and will bring the transaction up with the BCUC on August 3, 2005 when it convenes the latest TER rate hearing. **We assume regulatory approvals will be received in the 5-month timeline given.**
-

Exhibit 3 – Historical Regulated Asset/Company Transactions

Sellers	Asset/Company	Buyer	Date	Est. P/B Regulated Equity	Est. Share Takeover Premium
Terasen	**100% of Company**	**Kinder Morgan**	**Q4/05**	**2.6x**	**14 - 20%**
TransAlta Utilities	Alberta Transmission	OTPP/SNC Lavalin	Q2/02	1.85x	n/a
Westcoast Energy	100% of Company	Duke Energy	Q1/02	1.85x	15%
Westcoast Energy	Centra B.C	BC Gas (Terasen)	Q1/02	1.3x	n/a
TransAlta Utilities	Alberta Electricity Distribution	Utilicorp	Q1/01	1.8x	n/a
Westcoast Energy	Centra Manitoba Gas Distribution	Manitoba Hydro	Q3/99	2.1x	n/a
Westcoast Energy	Centra Alberta Gas Distribution	AltaGas	Q2/98	1.8x	n/a
British Gas	Consumers Gas	Enbridge	Q2/94	1.8x	30%
Maritime Electric	100% of Company	Fortis	Q3/94	1.4x	28%
Union Energy	100% of Company	Westcoast	Q4/92	1.5x	32%

Source: Company Reports, Scotia Capital.

Duke/Westcoast Deal Precedent: On September 23, 2001 Duke Energy offered a 15% share price premium for 100% of Westcoast Energy at that time. This is likely the precedent transaction which formed the structure of the KMI/TER deal. The Duke/Westcoast deal took just over 5 months to complete, with the closing coming in a few weeks late due to a specific U.S. FERC regulatory issue with one of the assets (Maritimes & Northeast Pipeline). We believe that the KMI/TER deal will fit into this precedent timeline (See Exhibit 3 for precedent transaction details).

- **Other Possible Suitors:** The only Canadian company that could takeover Terasen and enjoy material synergies is Enbridge (ENB). Other U.S. or international companies (including China's) could be interested in TER's growth prospects and oil sands exposure; however, KMI has already paid a record sector premium. KMI noted that the deal was done for its growth prospects and that cost savings were likely going to be limited to some minor operating redundancies. This is typical of most utility acquisitions.
- **Financing Terasen:** KMI did specify its debt to total cap after closing the Terasen deal would be 56% versus 53.9% as of June 30, 2005. We speculate that KMI will issue a Canadian debt instrument through a wholly owned Canadian sub similar to a Dominion Resources' Canadian issue that used a Nova Scotia incorporated subsidiary.

Background: TER's Growth Outlook

- **TMX:** On July 12, 2005 TER filed an application with the National Energy Board (NEB) to increase the capacity of the Trans Mountain pipeline by 35,000 bbls/day from 225,000 bbls/day to 260,000 bbls/day for an estimated $210M (TMX Phase I) for Q1/07. The TMX Phase I was also included by the Canadian Association of Petroleum Producers (CAPP) in the ongoing TER ITS discussions. TER stated that the next TMX system expansion request will occur late in Q3/05 when TER will hold an open season for the $365M TMX 30 inch pipeline loop in Alberta and eastern BC (Phase II), which could lead to an eventual twinning of the entire Trans Mountain system (Phase III) that would transport crude to Vancouver for delivery to U.S. refineries in California or a northern leg into Prince Rupert that will transport oil sands crude to Prince Rupert for export to Asia via VLCC tankers. The northern leg option is identical to ENB's Gateway Oil Pipeline proposal. TMX 2 and 3 could add 625,000bbls/day.
  - **CAPP Increases Canadian Oil Production Forecast:** On July 19, 2005, CAPP raised its total Canadian crude oil production forecast from 3.6M bbls/day to 3.9M bbls/day in 2015. CAPP increased forecast 2015 conventional oil production in Western Canada by 125K bbls/day and oil sands production by 100K bbls/day from the 2004 numbers. CAPP had previously estimated that 600K bbls/day of new pipeline capacity will be required to service incremental oil sands production over the next decade. **We believe that with CAPP's latest revision, 825K bbls/day may be necessary.** There are various projects including TER's TMX (625K bbls/day), ENB's Gateway (400K bbls/day), TRP's Keystone pipeline (435K bbls/day), Koch's Minnesota pipeline (350K bbls/day) and Southern Access (250K bbls/day) that are competing.
  - ENB's $2.5B Gateway oil export pipeline project and $1.7B condensate import line (less $600m if built together) are claimed to be ahead of Terasen's TMX project at this time. TRP's US$1.7B Keystone oil pipeline proposal from Alberta to Illinois initially appears to be too little too late.

- **Corridor Expansion:** TER is in an exclusive negotiation with Shell for the $800M Corridor pipeline expansion in Alberta with an estimated in service date of 2009. TER stated that it is currently working on engineering and environmental plans for the 42 inch expansion from Muskeg River to Edmonton which could carry 1M bbls/day. Shell will likely have a minimum take or pay contract to guarantee TER a certain minimum return on the investment, but TER noted there would be significant capacity left for third party shippers. The benefit from allowing third party shippers will be split somehow between Shell and TER.
- Additionally, for more information on Canadian crude oil pipelines please see pages 59 - 63 from our July 2005 *Gas & Electric Utilities Outlook.*

SC Online Analyst Link

Appendix A: Important Disclosures

Company	Ticker	Disclosures*
Enbridge Inc.	ENB	H3, S
Terasen Inc.	TER	H3
TransCanada Corporation	TRP	H3, S

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The stock is expected to perform approximately in line with the average total return of the analyst's coverage universe by sector over the next 12 months.

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Low financial and operational risk, high predictability of financial results, low stock volatility.

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Moderate financial and operational risk, moderate predictability of financial results, moderate stock volatility.

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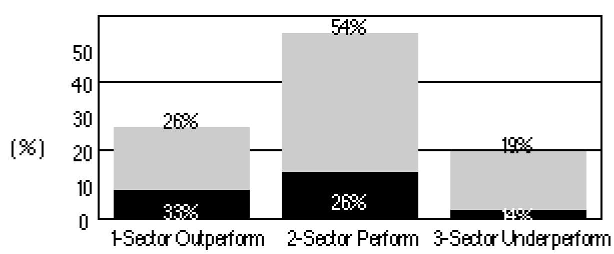

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* As at July 29, 2005.

Source: Scotia Capital.

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TD Newcrest

Action Notes

January 31, 2005
Equity Research

Pipelines, Power & Utilities

Recommendation: HOLD
Unchanged
12-Month Target Price: C$27.30
Unchanged
12-Month Total Return: -3.0%

Market Data (C$)	
Current Price ($)	29.02
52-Wk Range ($)	22.00 - 50.00
Mkt Cap (f.d.)($mm)	3,041.3
Dividend ($)	0.84
Yield (%)	2.9

Financial Data (C$)	
Fiscal Y-E	December
Shares O/S (f.d.)(mm)	104.8
Float (mm)	104.8
BVPS (basic)($)	12.71
Net Debt/Tot Cap (%)	67.5
ROE (%)	11.2

Estimates (C$)			
Year	**2003A**	**2004E**	**2005E**
EPS (f.d.)($)	1.32	1.41	1.49
CFPS (basic)($)	2.82	2.69	2.86
DI ($)	0.77	0.83	0.89

Valuations			
Year	**2003A**	**2004E**	**2005E**
P/E (f.d.)(x)	20.5	19.2	18.2
P/CFPS (basic)(x)	9.6	10.1	9.5
P/DI (x)	35.2	32.6	30.4

Linda Ezergailis, P.Eng.
416 983 7784
linda.ezergailis@tdsecurities.com

Michael McGowan, CA (Associate)
416 308 3404
michael.mcgowan@tdsecurities.com

Notes:
All figures in Canadian dollars, unless otherwise specified.

Please see the final pages of this document for important disclosure information.

Terasen Inc.

(TER-T; C$29.02)

Terasen Raises Stakes in West Coast Pipeline Race

Event
Terasen announced that phase 1 of its proposed TMX pipeline expansion project received a high level of endorsement during the company's recent expression of interest solicitation.

Impact - Mildly Positive
Support for phase 1 of the proposed project appears to be broadly based. In total, 17 shippers, including Canadian producers, west coast refiners, and Far East refiners, indicated strong endorsement for the project. However, no clear consensus on which route out of the Northern or Southern Options emerged during the solicitation.

While we view this development positively, expressions of interest are non-binding and we consider the upcoming open season to be a more important milestone.

Details
Phase 1 of the TMX expansion would expand TransMountain's capacity by 75,000 bbls/d to 300,000 bbls/d from the existing 225,000 bbls/d. Initially, 35,000 bbls/d of additional capacity will be derived from adding pump stations, followed by an incremental 40,000 bbls/day from looping 178 km of the existing system. The pump upgrades could be in service by the end of 2006 at an estimated cost of $205 million, while looping could be completed by the end of 2008 at an estimated cost of $365 million.

For a more detailed explanation of the Southern and Northern pipeline expansion opportunities available after the completion of phase 1, please see our *Action Note* dated December 8, 2004.

Valuation
Our $27.30 target price is based on our 2006 estimates, 10-year bond yield assumption of 4.5%, and the following blended valuation: 1) 50% relative earnings yield to 10-year bond of 126% (versus historical average of 124%); 2) 25% relative dividend yield to 10-year bond of 76% (versus historical average of 72%); and 3) 25% price-to-book value of 1.9 times (versus the historical average of 1.7x). It implies a 17.6x price-to-earnings multiple and 3.4% dividend yield, compared to historical averages of 14.2x and 4.2%, respectively.

We believe Terasen deserves a premium versus the sector due to management's track record of value creation, our expectation of above-utility-average growth, and strong fundamentals of its petroleum transportation business. Terasen has traded at a premium to the sector, and we expect this premium to continue.

Key risks to our target price include: 1) materially different bond yields versus our estimate, 2) potential reduction in the historical valuation premium vs. the sector, 3) tougher-than-expected competition for new oil transmission pipeline capacity, 4) unexpected negative surprises on the regulatory front, and 5) substantial delays and/or cancellations of oil sands projects.

Conclusion
While we believe that the results from the expression of interest solicitation are positive, Terasen's TMX expansion faces competition from Enbridge's Gateway proposal. The upcoming open season will be a more telling indicator of TMX's prospects because it will force producers not only to commit to building the project but also to a specific company (i.e. Enbridge or Terasen).

We are maintaining our HOLD recommendation based on our opinion that Terasen is fairly valued. We will continue to monitor the company's progress on its proposed greenfield projects, the renewal of the existing TransMountain incentive tolling agreement in late 2005 and the results of Terasen's TMX open season solicitation.

TD Newcrest Equity Research Disclosures

Company	Ticker	Disclosures
Terasen Inc.	TER-T	1, 2, 4, 14

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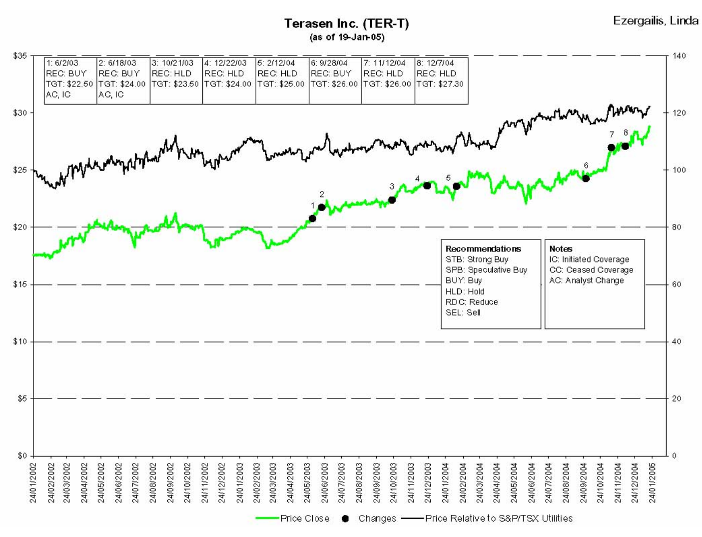

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TD Newcrest

Action Notes

February 17, 2005
Equity Research

Pipelines, Power & Utilities

Recommendation: HOLD
Unchanged
12-Month Target Price: C$29.00 ↑
Prior: C$28.50
12-Month Total Return: 1.9%

Market Data (C$)	
Current Price ($)	29.34
52-Wk Range ($)	21.50 - 29.91
Mkt Cap (f.d.)($mm)	3,086.6
Dividend ($)	0.90
Yield (%)	3.1

Financial Data (C$)	
Fiscal Y-E	December
Shares O/S (f.d.)(mm)	105.2
Float (mm)	105.2
BVPS (basic)($)	13.04
Net Debt/Tot Cap (%)	65.4
ROE (%)	11.2

Estimates (C$)			
Year	**2004A**	**2005E**	**2006E**
EPS (f.d.)($)	1.42	1.46	1.55
EPS (f.d.)(old)($)	1.41	1.49	1.55
CFPS (basic)($)	2.83	2.83	3.11
DI ($)	0.83	0.90	0.96

Valuations			
Year	**2004A**	**2005E**	**2006E**
P/E (f.d.)(x)	20.7	20.1	18.9
P/CFPS (basic)(x)	10.9	10.3	--
P/DI (x)	35.3	33.0	--

Linda Ezergailis, P.Eng.
416 983 7784
linda.ezergailis@tdsecurities.com

Michael McGowan, CA (Associate)
416 308 3404
michael.mcgowan@tdsecurities.com

Notes:
All figures in Canadian dollars, unless otherwise specified.

Please see the final pages of this document for important disclosure information.

Terasen Inc.

(TER-T; C$29.34)

Surprise Dividend Increase

Event - Q4/04 Earnings Release
Terasen reported Q4/04 EPS of $0.51 (f.d.), which was five cents below our estimate of $0.56 (f.d.) and $0.02 below Q4/03 adjusted EPS of $0.53 (f.d.). Q4/03 EPS was adjusted to reflect a $1.8 million writedown against Terasen's investment in Westport Innovations Ltd. In addition, earnings were restated to reflect a change in the quarterly accounting for income tax - Terasen now records quarterly tax expense by applying its effective tax rate to pretax income for the quarter as opposed to its previous method of allocating quarterly income tax based on actual taxes estimated to have been collected in rates. This change affects quarterly tax allocations, but has no effect on annual EPS.

In concert with the Q4/04 earnings release, Terasen's board approved a 7.1% increase in the dividend to $0.90 (annualized) from $0.84. In previous years, Terasen's Board timed dividend increases to coincide with Q1 earnings.

Impact - Mildly Positive
We have adjusted our 2005E EPS down by $0.03 to $1.46 to reflect slightly higher other expenses. Our 2006E EPS of $1.55 remains intact.

Our dividend estimate for 2006E has increased by three cents to $0.96 reflective of our expectation that annual dividend increases will now be declared in conjunction with Q4 earnings releases instead of with Q1 releases.

Our target price increases to $29.00, reflective of our slightly higher 2006 financial forecasts.

Details
Natural Gas Distribution reported a decline in earnings to $42.6 million in Q4/04 from $44.8 million in Q4/03, which was primarily due to the 27 bps reduction in allowed ROE experienced in 2004. Although we expected reduced returns at the Gas Distribution division due to relatively low regulated ROEs, the division's 2004 annual performance exceeded our expectations and the strong cost performance there partially offset increased costs in other divisions (Terasen estimates its achieved $4.1 million in cost efficiencies during 2004).

The **Petroleum Transportation** division earned $19.9 million in Q4/04, up from $17.9 million in Q3/04. A 2.5% revenue decrease in Q4/04 to $58.5 million from $60.0 million caused by lower tolls on Trans Mountain was offset by increased throughput and operating efficiencies on the pipeline, and increased contributions from Express.

Water and Utility Services reported an earnings contribution of $0.7 million in Q4/04, up from $0.4 million in Q4/03. Contributions from the Fairbanks Sewer & Water Inc. acquisition, which closed on July 31, 2004 was partially offset by higher acquisition-related depreciation and other business development costs.

The **Corporate** segment increased its loss to $9.3 million in Q4/04 from $7.0 million in Q4/03 after adjusting for the $1.8 million writedown against Westport Innovations. The increased loss was due to an increase in financing costs and lower tax recoveries.

Updates on key initiatives included:

- News of preliminary approval to build a LNG storage facility on Vancouver Island. Final approval of the terminal is still subject to numerous conditions, the most important being the approval of a proposed gas-fired electricity plant on the island. The estimated cost of the LNG facility is between $90 and $130 million, with an anticipated in-service date between 2008-2009, assuming the project proceeds.
- Indication that the proposed TMX pipeline expansion is proceeding well. While the final outcome of this project remains speculative, Terasen noted that it continues to talk with shippers and hopes to conduct a formal open season on Phase 1 of the project by the end of Q2/05.

- An announcement that discussions with Shell and other third party shippers to expand the capacity of its Corridor Pipeline in the oil sands region are still in progress.
- The announcement of a more conservative capital structure, with a goal of 30-33% equity as a percentage of total capital, after excluding preferred securities, which are now classified as debt and carry a weight of approximately 3%. In the past, Terasen had target a capital structure of 33% equity including the preferred securities, which is at the low end of the new range.
- Guidance that volumes on the Trans Mountain line will be weak during Q1/05 due to refinery turnarounds and production outages in the Alberta oil sands.

Outlook - Terasen has a stated long-term goal of growing EPS in the range of 6-8%, however, management consistently guided to EPS growth of 6% throughout the call. The reduced guidance was likely due to the relatively low regulated ROE rates (9.03% for 2005) the company is facing on its legacy natural gas distribution assets. Terasen's Trans Mountain pipeline is up for re-basing in 2005, which could also put pressure on earnings.

We assume that the proposed Vancouver Island LNG facility will ultimately proceed, and, this, combined with other greenfield opportunities, should bode well for longer-term returns. In the near-term, Terasen will likely focus on obtaining ROE relief during a potential generic cost of capital review with the BCUC (Q3/05), growing its water services division, and delivering cost performance.

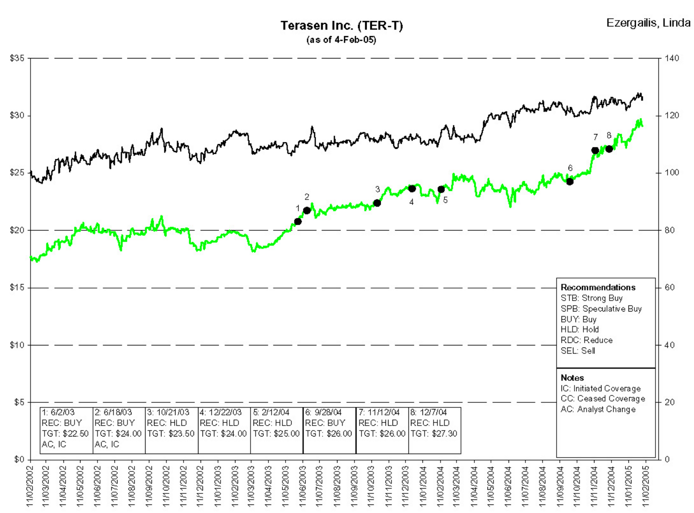
Valuation - Our $29.00 target price is based on our 2006 estimates, 10-year bond yield assumption of 4.3%, and the following blended valuation: 1) 50% relative earnings yield to 10-year bond of 124% (versus historical average of 124%); 2) 25% relative dividend yield to 10-year bond of 77% (versus historical average of 72%); and 3) 25% price-to-book value of 2.0 times (versus the historical average of 1.7x). It implies a 18.7x price-to-earnings multiple and 3.3% dividend yield, compared to historical averages of 14.2x and 4.2%, respectively.

We believe Terasen deserves a premium versus the sector due to management's track record of value creation, our expectation of above-utility-average growth, and strong fundamentals of its petroleum transportation business. Terasen has traded at a premium to the sector, and we expect this premium to continue.

Key risks to our target price include: 1) materially different bond yields versus our estimate, 2) potential reduction in the historical valuation premium vs. the sector, 3) tougher-than-expected competition for new oil transmission pipeline capacity, 4) unexpected negative surprises on the regulatory front, and 5) substantial delays and/or cancellations of oil sands projects.

Conclusion - In our view, Terasen's track record of EPS and dividend increases warrant a continued premium in the sector. We expect numerous infrastructure opportunities to offset the impact of any re-basing in Trans Mountain when its incentive tolling settlement expires at the end of this year. Given the modest returns implied by our target price; however, we continue to recommend that investors HOLD Terasen.

Price Graph



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Terasen Inc.	TER-T	1, 2, 4, 14

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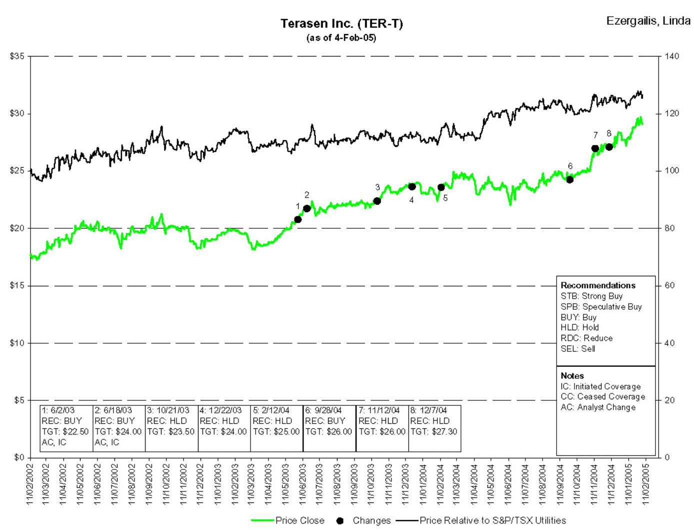

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SPECULATIVE BUY: The stock's total return is expected to exceed 30% over the next 12 months; however, there is material event risk associated with the investment that could result in significant loss.
HOLD: The stock's total return is expected to be between 0% and 15%, on a risk-adjusted basis, over the next 12 months.
REDUCE: The stock's total return is expected to be negative over the next 12 months.

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TD Newcrest

Action Notes

May 4, 2005
Equity Research

Pipelines, Power & Utilities

Recommendation: HOLD
Unchanged
12-Month Target Price: C$29.00
Unchanged
12-Month Total Return: 8.9%

Market Data (C$)	
Current Price ($)	27.45
52-Wk Range ($)	22.00 - 49.00
Mkt Cap (f.d.)($mm)	2,887.7
Dividend ($)	0.90
Yield (%)	3.3

Financial Data (C$)	
Fiscal Y-E	December
Shares O/S (f.d.)(mm)	105.4
Float (mm)	105.4
BVPS (basic)($)	13.45
Net Debt/Tot Cap (%)	68.4
ROE (%)	11.2

Estimates (C$)			
Year	**2004A**	**2005E**	**2006E**
EPS (f.d.)($)	1.42	1.46	1.55
CFPS (basic)($)	2.83	2.83	3.11
DI ($)	0.83	0.90	0.96

Valuations			
Year	**2004A**	**2005E**	**2006E**
P/E (f.d.)(x)	19.3	18.8	17.7
P/CFPS (basic)(x)	9.7	9.7	8.8
P/DI (x)	33.0	30.4	28.5

Linda Ezergailis, P.Eng.
416 983 7784
linda.ezergailis@tdsecurities.com

Michael McGowan, CA (Associate)
416 308 3404
michael.mcgowan@tdsecurities.com

Notes:
All figures in Canadian dollars, unless otherwise specified.

Please see the final pages of this document for important disclosure information.

Terasen Inc.

(TER-T; C$27.45)

Q1 Impacted by Oil Sands Disruptions

Event - Q1/05 Earnings Release
Terasen reported Q1/05 EPS of $0.63 (f.d.) vs. our estimate of $0.65 and Q1/04 EPS of $0.64 (f.d.). (Note that Q1/04 earnings were restated to reflect a change in the quarterly accounting for income tax. Effective Q4/04, Terasen records quarterly tax expense by applying its effective tax rate to pretax income for the quarter as opposed to its previous method of allocating quarterly income tax based on actual taxes estimated to have been collected in rates. This change affects quarterly tax allocations, but has no effect on annual EPS.)

Impact - Neutral

Details
Natural Gas Distribution's Q1/05 earnings of $55.7 million were largely consistent with earnings of $54.7 million in Q1/04, as operating efficiencies and customer growth at Terasen Gas were able to offset a 12 bps drop in allowed ROEs for 2005. A lower effective tax rate reduced income tax expense, while lower interest rates were able to reduce financing costs.

The **Petroleum Transportation** division's Q1/05 earnings declined by 31% to $12.7 million from $18.3 million in Q1/04. Current earnings contributions from the TransMountain system fell by 48% to $5.4 million from $10.4 million in Q1/04 as production outages in the oil sands and refinery turnarounds impacted throughput. A decrease in the allowed return on equity for the Corridor pipeline decreased its Q1/05 earnings contribution to $3.6 million from $3.9 million in Q1/04. The Express System was also affected by the operational outages in the oil sands, although not to the same degree as TransMountain. Q1/05 earnings contribution from Express fell to $3.7 million from $4.0 million in Q1/04.

Water and Utility Services reported a Q1/05 earnings contribution of $0.8 million vs. $nil in Q1/04. Strong economic growth in BC and Alberta led to improved results in the base waterworks and utility service businesses, while Fairbanks (acquired on July 31/04) made a small contribution during the seasonally weak first quarter.

The **Corporate** segment's Q1/05 loss declined to $2.9 million from $5.1 million in Q1/04. The decreased loss was due to higher revenues, the realization of a larger hedging gain at Clean Energy ($2.6 million in Q1/05, vs. $1.7 million in Q1/04), and lower operating and maintenance expenses, which were partially offset by higher financing costs (due to higher debt levels) and a lower income tax recovery.

Other Details
- Terasen continues to forward its **TMX** expansion, and might hold an open season in June or July for TMX 1 pump stations (+ 35,000 bpd at a cost of $205 million) and the Anchor Loop (+ 40,000 bpd at a cost of $365 million).
- The **Corridor Pipeline** could benefit from Shell's recent regulatory filings to increase capacity at two of its oil sands projects. Terasen is in discussions with Shell to build a $700-$900 million pipeline to transport the additional throughput.
- **Express System** recently completed its 108,000 bpd expansion, just under budget at US$100 million. Management is now exploring adding incremental capacity into the PADD II and PADD IV markets in the U.S.
- **Natural Gas Distribution** could benefit if the BC regulator goes ahead with a generic cost of capital hearing, as the 2005 generic ROE of 9.03% is one of the lowest in Canada.
- Terasen still plans to construct an LNG terminal on Vancouver Island to supply the proposed Duke Point natural gas fired plant, which is still facing local opposition. While the BC Court of Appeal refused to grant opposition groups leave to appeal the BCUC's decision to approve the power plant, a request has been filed with the Appeal Court review panel to reconsider this ruling. The review hearing is scheduled for early June.

Valuation
Our $29.00 target price is based on our 2006 estimates, 10-year bond yield assumption of 4.3%, and the following blended valuation: 1) 50% relative earnings yield to 10-year bond of

124% (versus historical average of 124%); 2) 25% relative dividend yield to 10-year bond of 77% (versus historical average of 72%); and 3) 25% price-to-book value of 2.0 times (versus the historical average of 1.7x). It implies a 18.7x price-to-earnings multiple and 3.3% dividend yield, compared to historical averages of 14.2x and 4.2%, respectively.

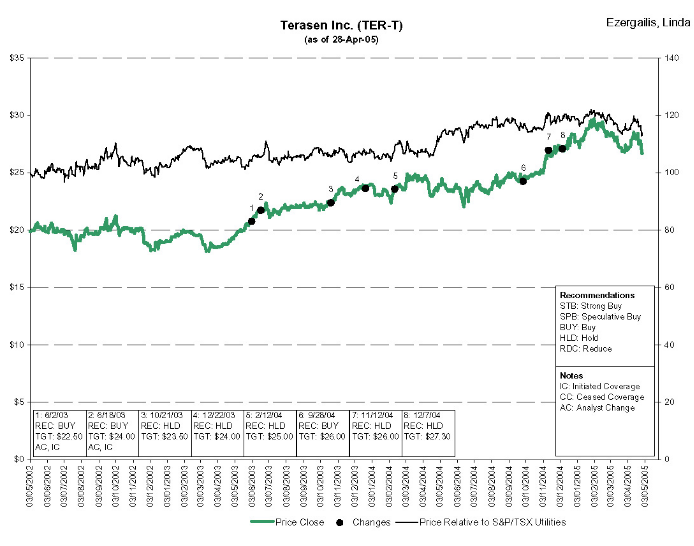
We believe Terasen deserves a premium versus the sector due to management's track record of value creation, our expectation of above-utility-average growth, and leverage to growing volumes in the oil sands. Terasen has traded at a premium to the sector, and we expect this premium to continue.

Key risks to our target price include: 1) higher than expected long bond yields, 2) acquisitions that do not create shareholder value, 3) operational disruptions, 4) potential reduction in the historical valuation premium vs. the sector, 5) tougher-than-expected competition for new oil transmission pipeline capacity, 6) regulatory surprises, 7) substantial delays and/or cancellations of oil sands projects, and 8) WCSB risk.

Outlook & Conclusion
Terasen's non-petroleum businesses will have to perform strongly in order for management to meet its 6% EPS growth target for 2005. In addition, TransMountain faces some re-basing risk in 2006. The potential for a generic cost of capital hearing in British Columbia later this year could provide some incremental upside for gas distribution utility returns in 2006. In addition, we assume the Vancouver Island LNG facility will proceed, which when combined with growth in the water services businesses and significant expansion potential for the oil pipelines, provides some visibility to continued high single-digit EPS growth.

In our view, Terasen's track record of shareholder value creation warrant a continued premium to the sector despite a tough start to 2005 and the potential re-basing of TransMountain in 2006. The modest returns implied by our target price; however, result in no change to our HOLD rating.

Price Graph



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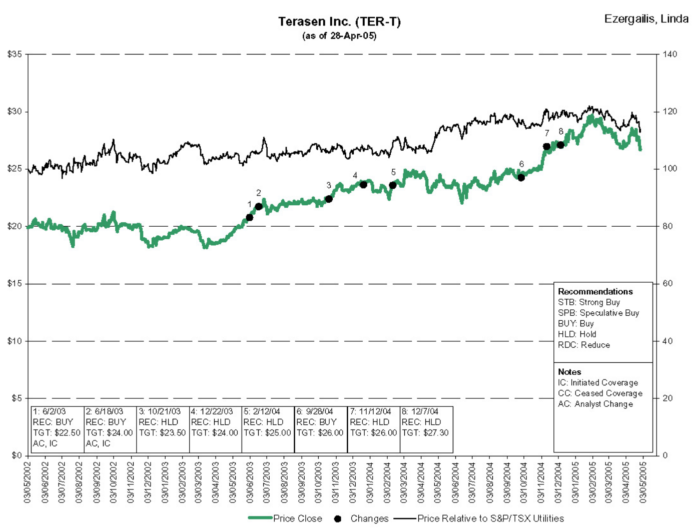
Price Graphs



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REDUCE: The stock's total return is expected to be negative over the next 12 months.

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TD Newcrest

Action Notes

August 2, 2005
Equity Research

Pipelines, Power & Utilities

Recommendation: BUY ↑

Prior: HOLD

12-Month Target Price: C$35.75 ↑

Prior: C$31.00

12-Month Total Return: 16.7%

Market Data (C$)	
Current Price ($)	31.40
52-Wk Range ($)	23.38 - 31.78
Mkt Cap (f.d.)($mm)	3,312.7
Dividend ($)	0.90
Yield (%)	2.9

Financial Data (C$)	
Fiscal Y-E	December
Shares O/S (f.d.)(mm)	105.5
Float (mm)	105.5
BVPS (basic)($)	13.53
Net Debt/Tot Cap (%)	67.9
ROE (%)	11.2

Estimates (C$)			
Year	**2004A**	**2005E**	**2006E**
EPS (f.d.)($)	1.42	1.48	1.55
CFPS (basic)($)	2.83	2.84	3.10
DI ($)	0.83	0.90	0.96

Valuations			
Year	**2004A**	**2005E**	**2006E**
P/E (f.d.)(x)	22.3	21.4	20.4
P/CFPS (basic)(x)	11.2	11.1	10.2
P/DI (x)	38.1	35.2	33.0

Linda Ezergailis, P.Eng.
416 983 7784
linda.ezergailis@tdsecurities.com

Michael McGowan, CA (Associate)
416 308 3404
michael.mcgowan@tdsecurities.com

Notes:
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Terasen Inc.

(TER-T; C$31.40)

Kinder Morgan Inc. to Acquire Terasen

Event – On August 1, 2005 Kinder Morgan Inc. (KMI) announced that it is has agreed to purchase Terasen (TER) for approximately US$5.6 billion, including the assumption of US$2.5 billion debt, and subject to regulatory and TER shareholder approvals. Both boards of directors have unanimously approved the transaction. The transaction is expected by year-end 2005. Under present terms, TER shareholders can elect to receive i) C$35.75 in cash; or ii) 0.3331 shares of KMI common stock, or iii) C$23.25 in cash plus 0.1165 shares of KMI common stock. Elections are subject to proration if total cash elections exceed 65% of total consideration to be paid, or stock elections exceed 35%. Based on KMI's share price and the CAD/USD exchange rate on July 29, 2005, the offer is worth approximately $35.91/share.

Impact – Positive

Attractive Valuation Leads Us to Not Expect Any Competing Bids: The offer represents a premium of approximately 20% over TER's 20-day average share price (14% over its July 29, 2005 closing price), 23.8x 2005 expected earnings, 11.5x 2005 projected EBITDA, and 2.6x price-to-book. We believe KMI is paying a premium for access to oil sands growth opportunities. We don't expect any competing bids. We don't believe any other U.S. company has the valuation and financial strength to pay this price. We also don't think it is likely that Enbridge or TransCanada would pay more for TER because they already have a presence in the WCSB and relationships with Canadian producers.

Great Strategic and Operational Fit: We believe that there is a strategic and operational fit with the two businesses. With a combined pro-forma E.V. of more than US$19 billion, KMI will have the local presence, resources and scale to compete with Enbridge (approx. EV of C$21 billion) and TransCanada (approx. EV of C$30 billion) to build new energy infrastructure in Canada, in our view. We see a cultural fit because both TER and KMI have 1) a track record of shareholder value creation delivering above-utility average total returns, 2) a focus on operational excellence, 3) ownership of predominantly fee-based or regulated businesses focused on the transportation and storage of energy products across North America, and 4) access to low cost-of-capital through tax-efficient structures. We expect further details on potential revenue and cost synergies to be provided on the conference call.

Diversifies Geography and Business Mix: While we view both companies as having relatively low-risk assets, the combined entity will have further diversified the geography and business mix. This is of particular benefit to Terasen shareholders, as its petroleum pipeline operations service only one basin (WCSB), and its British Columbia based natural gas distribution business is required to compete with the province's with low-cost hydroelectricity. The combined entity will own and operate interest in natural gas pipelines, crude oil and refined product pipelines, natural gas distribution, and four power plants.

Details

Shareholders Approval Needed: Terasen will hold a special meeting of shareholders to approve the transaction no later than October 31, 2005. For the deal to proceed, 75% of TER shareholders in attendance must vote in favor of the transaction. There is a $75 million, or approximate $0.71 per share, break fee should TER shareholders reject KMI's offer, or accept a competing bid.

We Expect Regulatory Approvals Will be Granted: The transaction is subject to regulatory approval in both Canada and the US. We believe that KMI's intention to maintain Terasen Gas' head office in Vancouver, BC should ease some of any potential local concerns surrounding potential domestic job losses in British Columbia.

Details on Kinder Morgan: Headquartered in Houston, Texas, KMI is one of the largest midstream energy companies in the U.S., operating more than 35,000 miles of natural gas and products pipelines and approximately 145 terminals that store and handle products like gasoline and coal. KMI also owns a 240,000 customer natural gas retail distribution network in Colorado, Wyoming, and Nebraska. Kinder Morgan Inc. own approximately 16% of Kinder Morgan Energy Partners L.P. (KMP), and acts as its general partner. KMI and KMP have a combined E.V. of approximately U.S. $30 billion. The CEO Richard D. Kinder owns about 19% of KMI and receives a salary of $1 per year with no bonuses, no option grants, and no restricted stock. Over the past six years, KMI has delivered 40% annualized total returns.

Conference Call Information: Kinder Morgan will host a live webcast at www.kindermorgan.com at 8:30 AM ET, August 2, 2005 to discuss the transaction. Terasen will host a separate call at 10:00 AM ET (1-877-375-5688).

Valuation: Our target price of $35.75 is based on our view that the acquisition of TER by KMI will proceed under the current terms at what we view as an attractive cash offer. Note that we attribute a low probability to a higher competing offer. This new target price implies a P/E of 23.1x our standalone 2006E Terasen EPS, a historically high valuation.

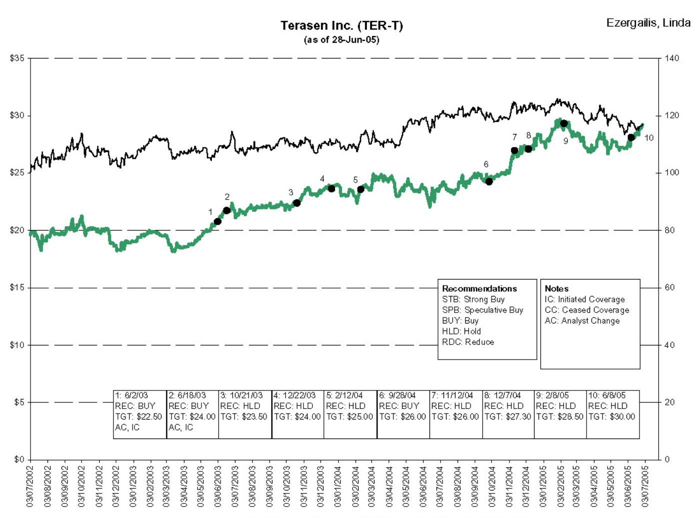
Key risks to our target price include: 1) regulatory and Terasen shareholder approvals for the transaction, 2) post-merger integration risk, 3) higher than expected long bond yields in North America, 4) lower than expected earnings and cash flow growth by Kinder Morgan 5) tougher-than-expected regulatory decisions, 6) operational disruptions, and 7) a competing higher offer.

Conclusion - Expect the Stock to Trade Up: We are upgrading Terasen to BUY purely based on the total returns implied by the closing price on July 29, 2005; however, we expect the stock to trade up rapidly to between $34 and 35 (just below the offer price in recognition of the time value of money and relatively low transaction risk), and we would accumulate the shares up to $34. We do not expect the shares to trade above the offer price as we view the probability of a competing bid as low.

We believe that this acquisition would create substantial value for TER shareholders. While there is some transaction risk associated with an acquisition of this scale, we believe that regulatory and TER shareholder approvals will be granted. In addition, the challenges of integrating two organizations with unique cultures could result in transaction EPS accretion to Kinder Morgan Inc. shareholders falling short of six to eight percent in 2006; however, given the track record of Kinder Morgan management we believe that the post-merger integration risk is modest.

Conclusion - Broad Implications for the Canadian Sector : This announcement dramatically alters the competitive landscape, as it creates a third large pipeline and energy infrastructure company in Canada. We expect high levels of competition between KMI, Enbridge, and TransCanada for the mandate to build new energy infrastructure, especially as it relates to the oil sands and Alaskan gas. While it is possible for Enbridge and TransCanada to compete with their current scale, we believe that these companies will likely consider a strategic response over the coming year. This could come in the form of an acquisition of a U.S. company to achieve north-south scale economies. It is also feasible that Enbridge and TransCanada consider a merger between themselves, as there is little overlap in their current businesses and it would likely bring revenue and cost synergies. ***We will be updating our thesis on all companies in the sector in the near term as a result of this acquisition announcement.***

Price Graph



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Company	Ticker	Disclosures
Terasen Inc.	TER-T	1, 2, 4, 14
Enbridge Inc.	ENB-T	1, 2, 4, 9, 13, 14
TransCanada Corp.	TRP-T	2, 13, 14

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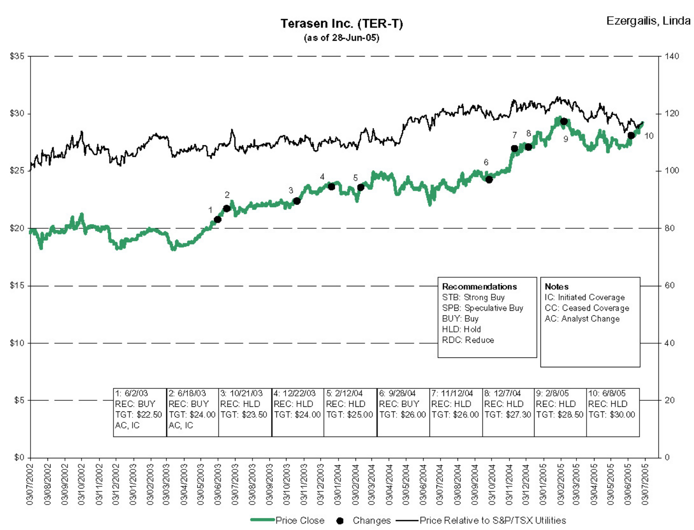

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TD Newcrest

Action Notes

August 3, 2005
Equity Research

Pipelines, Power & Utilities

Recommendation: N/A
12-Month Target Price:N/A
12-Month Total Return:N/A

Market Data (C$)	
Current Price ($)	36.00
52-Wk Range ($)	23.38 - 31.78
Mkt Cap (f.d.)($mm)	3,312.7
Dividend ($)	0.90
Yield (%)	2.9

Financial Data (C$)	
Fiscal Y-E	December
Shares O/S (f.d.)(mm)	105.5
Float (mm)	105.5
BVPS (basic)($)	13.53
Net Debt/Tot Cap (%)	67.9
ROE (%)	11.2

Estimates (C$)			
Year	**2004A**	**2005E**	**2006E**
EPS (f.d.)($)	1.42	1.48	1.55
CFPS (basic)($)	2.83	2.84	3.10
DI ($)	0.83	0.90	0.96

Valuations			
Year	**2004A**	**2005E**	**2006E**
P/E (f.d.)(x)	22.1	21.2	20.3
P/CFPS (basic)(x)	11.1	11.1	10.1
P/DI (x)	37.8	34.9	32.7

Linda Ezergailis, P.Eng.
416 983 7784
linda.ezergailis@tdsecurities.com

Michael McGowan, CA (Associate)
416 308 3404
michael.mcgowan@tdsecurities.com

Notes:
All figures in Canadian dollars, unless otherwise specified.

Please see the final pages of this document for important disclosure information.

Terasen Inc.

(TER-T; C$36.00)

Terasen and Kinder Morgan Discuss Merger

Event: Kinder Morgan and Terasen hosted conference calls to discuss Kinder Morgan Inc.'s (KMI) proposed acquisition of Terasen. Please see our Terasen *Action Note* dated August 2, 2005 for more details on the transaction.

Impact – Neutral

Details: Some new information and additional context was provided on the respective conference calls. Our takeaways are as follows:

Rationale for Terasen's Acceptance of KMI's Bid: KMI's bid was an unsolicited offer that Terasen felt it could not refuse. Terasen has had high-level, ongoing discussions about potential partial and total business combinations. Based on its perception of maximizing shareholder returns, and a review of KMI's bid by an external adviser, Terasen felt that KMI's offer was very attractive.

Preliminary Customer and Regulatory Reaction: Terasen perceives a generally favorable reaction by key stakeholders, based on preliminary discussions with various Canadian governments, regulators, customers and pension fund partners.

Growth Opportunities More the Focus than Cost Synergies: Terasen does not view much risk in customers or partners seeking to participate in benefits of the acquisition (and thereby potentially diluting benefits to Kinder Morgan) as the rationale for the transaction was based on the strategic fit, oilsands volume growth and improved competitive positioning rather than wringing operating synergies out of the combined entity. We note, however, that Terasen Gas is requesting a higher ROE and equity thickness from the BCUC, and given the premium KMI is paying for the parent company, Terasen's previous argument that its allowed rates of return hinder its ability to attract capital may be less persuasive. In addition, the TransMountain pipeline is in negotiations for a new 5-year deal with shippers. Our perception is that KMI is factoring in continuing high returns from this pipeline, and we see that as optimistic given our view on the likelihood of at least some re-basing.

BCUC Review Expected to be the Largest: Out of the many regulatory reviews to which this transaction will be subject, KMI expects the BCUC's to be the largest, since there will be an onus on KMI to prove that the transaction will not be detrimental to existing ratepayers and in fact all stakeholders. KMI believes that this risk has been mitigated by its decision to allow Terasen Gas to continue operating as an autonomous business unit, with the Terasen Gas head office remaining in Vancouver. In addition, Terasen believes that Duke Energy's 2001 acquisition of Westcoast Energy, which received regulatory approval, will serve as a precedent and that the regulator should be relatively indifferent to this transaction since the majority of acquisition related changes will occur at the corporate parent rather than at Terasen Gas Inc.

Other Details

- The tax-efficient Express Pipeline structure is fully protected under this acquisition.
- Terasen's CEO will be focused on consummating the transaction, and it is still to be determined whether he will sit on KMI board or obtain a senior position within KMI after the deal is completed.
- Non-electing Terasen shareholders will receive proceeds of 65 % cash and 35% KMI stock.
- There are no plans to offer KMI exchangeable shares to Terasen shareholders.

Outlook and Conclusion: Based on the information provided on the respective conference calls, our view continues to be that the transaction will likely proceed, and competing bids are unlikely. We believe that Terasen shares are now trading on the basis of the underlying value of the 65% cash and 35% stock offer, and will likely continue to do so until the transaction is finalized.

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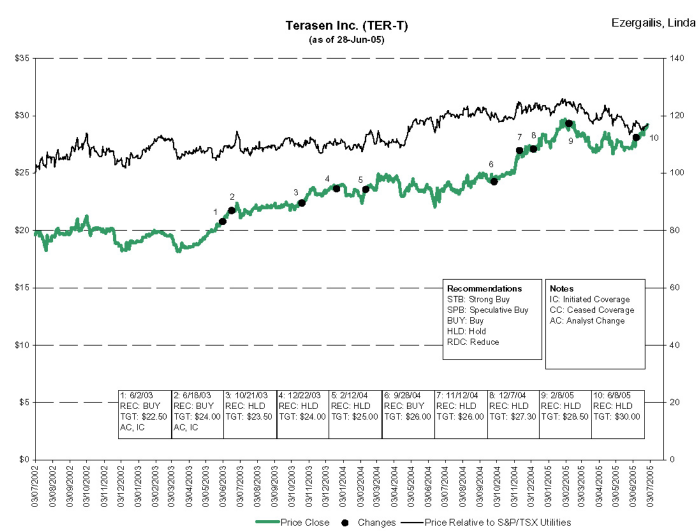

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Terasen Inc.

Rating	Neutral 1 *Unchanged*
Price target	C$28.00/US$22.79 *Unchanged*
Price	C$29.34/US$23.81

RIC: TER.TO BBG: TER CN

17 February 2005

A full pipeline of opportunities

■ Earlier than expected dividend increase

Terasen reported Q4 2004 EPS of C$0.51 which was below our estimate of C$0.55 and the Street's view of C$0.58, however, we note a considerable part of the difference arose from a regulatory accounting change that does not impact overall annual earnings. Positively, the company increased its dividend one quarter earlier than expected.

■ Better things to come

Overall this quarter (after considering the accounting change) was largely in line with expectations, however, we continue to believe that better things are potentially ahead for Terasen's oil sands related exposure.

■ Abundant opportunities, but slow and steady

While Terasen faces a number of somewhat compelling opportunities, we believe only a seletion of these prospects will come to fruition. Additionally, we believe the progression into a much larger and potentially higher earning and returning company will take some time to develop.

■ Valuation: C$28.00 12-month target price

We continue to utilize multiple valuation methods to obtain our C$28.00 12-month target price, including: a 17.5x P/E multiple on our 2006 earnings estimate; a projected dividend yield of 3.2%; and, a dividend yield spread of 180 bps. We retain our Neutral 1 rating.

Highlights (C$m)	12/03	12/04	12/05E	12/06E	12/07E
Revenues	1,848	1,957	2,022	2,074	2,163
EBIT	338	377	395	397	432
Net income (UBS)	111	156	163	172	179
EPS (UBS, C$)	1.27	1.41	1.52	1.61	1.67
Net DPS (UBS, C$)	0.76	0.82	0.90	0.93	0.98

Profitability & Valuation	5-yr hist. av.	12/04	12/05E	12/06E	12/07E
EBIT margin %	-	19.3	19.5	19.2	20.0
ROIC (EBIT) %	-	9.4	10.0	9.9	10.7
EV/EBITDA x	-	10.3	11.0	10.9	10.1
PE (UBS) x	-	17.3	19.2	18.3	17.5
Dividend yield %	-	3.4	3.1	3.2	3.3

Source: UBS adjusted EPS is stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of C$29.34 on 17 Feb 2005

Andrew M. Kuske

andrew.kuske@ubs.com

+1-416-814 3663

Trading data (local/US$)	
52-wk. range	C$29.71-22.05/US$24.10-16.00
Market cap.	C$3.07bn/US$2.50bn
Shares o/s	105m (COM)
Free float	100%
Avg. daily volume ('000)	98
Avg. daily value (C$m)	2.7

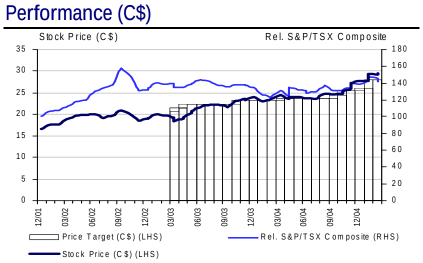
Balance sheet data 12/05E	
Shareholders' equity	C$1.62bn
P/BV (UBS)	1.9x
Net cash (debt)	(C$2.94bn)

Forecast returns	
Forecast price appreciation	-4.6%
Forecast dividend yield	3.1%
Forecast stock return	-1.5%
Market return assumption	7.8%
Forecast excess return	-9.3%

EPS (UBS, C$)

	12/05E			12/04
	From	To	Cons.	Actual
Q1E	-	0.79	*0.81*	0.77
Q2E	-	0.15	*0.11*	0.10
Q3E	-	(0.02)	*(0.04)*	(0.01)
Q4E	-	0.60	*0.64*	0.51
12/05E	1.48	1.52	*1.50*	
12/06E	1.54	1.61	*1.56*	

Performance (C$)



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Terasen reported Q4 2004 EPS of C$0.51 versus adjusted EPS of C$0.52 one year earlier. The quarterly result was below our C$0.55 estimate and the Street's C$0.58, however, we note a considerable part of the difference arose from a regulatory accounting change that does not impact overall annual earnings. For the full year, after adjusting for an unrealized hedge gain, the company's results were in line with our expectations of C$1.40 which reinforces the accounting change only having an impact on the allocation of taxation through the quarters and not on the full year's economics. Positively, the company deviated from its usual approach of raising its dividend with the Q1 results and increased the dividend one quarter earlier than expected. We continue to believe Terasen faces relatively good prospects in its core business areas. In our view, strong crude fundamentals, continued oil sands growth prospects and new market access issues underpin a significant portion of Terasen's future growth. This research note is divided into three categories: (1) results; (2) going forward; and, (3) valuation.

Continuing to exceed expectations

Results

Terasen reported Q4 2004 EPS of C$0.51 versus adjusted EPS of C$0.52 one year earlier. The quarterly result was below our C$0.55 estimate and the Street's C$0.58, however, we note a considerable part of the difference arose from a regulatory accounting change that does not impact overall annual earnings. For the full year, after adjusting for an unrealized hedge gain, the company's results were in line with our expectations of C$1.40 which reinforces the accounting change only having an impact on the allocation of taxation through the quarters and not on the full year's economics. Our segmented analysis appears below.

Annual earnings in line with expectations

Natural gas distribution

The full year earnings generated by Terasen's natural gas distribution unit were largely in line with expectations, however, as discussed above, there was a regulatory accounting change that impacts past and future quarterly earnings potential for this segment. Table 1 contains the restated earnings for Terasen Gas.

Modest (and immaterial) restatement

Table 1: Natural Gas earnings restatement (C$ millions)

	2004				2003			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Restated	36.2	(13.3)	(1.2)	48.0	37.5	(14.4)	(1.9)	51.4
Previous	42.2	(24.7)	(8.5)	60.7	45.3	(25.5)	(8.3)	61.1

Source: Company reports

The restatement involves the method for calculated income tax expense. The change does not affect full year earnings, however, quarterly earnings are impacted by this change. Previously, Terasen Gas' annual tax expense had been allocated based on budgeted sales revenue for the four quarters. Beginning in the fourth quarter of 2004, Terasen Gas' income tax expense is determined by applying the effective annual tax rate to the pre-tax income in the quarter. This treatment is much more consistent with the existing peer group. Selected comparative data appears in Table 2.

Table 2: Natural gas distribution data points

	Q4 2004	Q4 2003	Q3 2004	FY 2004	FY 2003	Q4 Chg (%) y-o-y	Chg (%) sequential	FY Chg (%) y-o-y
Earnings (C$millions)								
Terasen Gas	36.2	37.5	-24.8	69.7	72.6	-3.5%	-246.0%	-4.0%
TGVI	6.4	7.3	6.8	26.2	26.2	-12.3%	-5.9%	0.0%
Total	42.6	44.8	-18	95.9	98.8	-4.9%	-336.7%	-2.9%
Number of Customers			866,311	875,166	859,183		1.0%	1.9%
Volumes (petajoules)								
Sales Vols	41.1	43.9	12.6	121.6	125.6	-6.4%	226.2%	-3.2%
Transportation vols	19.6	20.2	14.5	72.2	72.2	-3.0%	35.2%	0.0%
Throughput	5.5	4	6	17.5	12.6	37.5%	-8.3%	38.9%

Source: Company reports and UBS

Solid customer growth and transportation volumes

Additional pertinent information include: (a) y-o-y, the number of natural gas customers increased by 1.0% over the course of Q4, and 1.9% for the full year; (b) operations and maintenance costs increased by a very modest 0.6% for the full-year 2004; and, (c) financing costs declined by roughly 6.9% in 2004. In summary, aside from the accounting change, these results were roughly inline with our expectations.

Petroleum transportation

Similar to Natural Gas Distribution, this segment performed inline with our expectations by delivering net earnings growth of 11.2% in Q4 2004 and 26.2% in 2004 on a year-over-year basis (see Table 3). Trans Mountain and the Express System produced the majority of the growth during Q4, while the Express System and Corridor delivered the bulk of the Petroleum Transportation segment's growth over the full year. Strong volumetric growth on all of the systems helped contribute to increased revenues that aided profitability.

Table 3: Petroleum transportation data points

	Q4 2004	Q4 2003	Q3 2004	FY 2004	FY 2003	Q4 Chg (%) y-o-y	Chg (%) sequential	FY Chg (%) y-o-y
Earnings (C$millions)								
Trans Mountain	11.2	10	8.8	39.4	35.8	12.0%	27.3%	10.1%
Express System	4.9	3.9	3.8	15.9	9.7	25.6%	28.9%	63.9%
Corridor	3.8	4	3.9	15.6	10.7	-5.0%	-2.6%	45.8%
Total	19.9	17.9	16.5	70.9	56.2	11.2%	20.6%	26.2%
Volumes (b/d)								
Trans Mtn C mainline	239,100	218,500	241,100	236,100	216,100	9.4%	-0.8%	9.3%
Trans Mtn US mainline	89,300	57,700	86,900	91,700	54,600	54.8%	2.8%	67.9%
Express System	175,400	174,000	178,200	175,300	171,200	0.8%	-1.6%	2.4%
Total	503,800	450,200	506,200	503,100	441,900	11.9%	-0.5%	13.8%

Source: Company reports and UBS

We believe Terasen's Trans Mountain Pipeline and the Westridge Dock are enviably positioned to continue benefiting from very robust Californian refinery margins.

Water and utility services

Reflecting the contribution of Fairbanks acquisition, among other factors, net income improved by more than 50% to C$6.6 million for 2004, up from C$4.1m in 2003.

Other activities

Year-over-year performance in 2004 weakened in this segment by delivering a disappointing loss of C$23.3 million versus a loss of C$23.0 million in the previous year.

Going forward

We believe Terasen investors, whether existing or prospective, should be aware of three major issues: (1) Oil sands affection; (2) New market development; and, (3) Gas distribution growth. Each of these will be addressed in greater detail below.

Oil sands affection?

Fundamentally, we have viewed the oil sands as a unique investment opportunity that may provide relatively visible growth over an extended period of time. Moreover, we regard pipelines that provide takeaway capacity from the oil sands as being similarly unique. The ongoing strength in global oil prices has led to an increased amount of investor attention being directed towards oil sands related companies, including Enbridge and Terasen. As several of the large oil and gas companies are on the verge of embarking upon significant capital programs for continued or new oil sands development, we believe a number of investors are building significant expectations into an indirect method of playing oil sands developments: the liquids pipeline companies. In our view, this increased affection towards oil sands related names has moderately boosted recent valuations. Yet, as per capital expenditure theory, we are likely to become far less bullish when the major capital programs commence. Prior to that time, we continue to believe that "oil sands affection" along with a number of other factors are likely to support rather robust valuations for selected oil sands pipeline plays.

Increased affection towards oil sands names

Go west, young man, go west!

In our report titled "*Go west, young man, go west!*" (dated 27 January 2005), we have outlined a number of issues related to new market development for western Canadian crude and related products. Much of the thrust for new market development arises from the necessity of avoiding a significant market saturation of Canadian crudes (including heavy and synthetic) in any one market region. In our view, new market development is necessary and Terasen is likely to benefit from such market diversification. We continue to believe a number of market areas will be attractive and necessary for Canadian based producers. By way of corollary, the pipeline and appropriate transportation network serving those markets will be equally important. Potential developments such as Enbridge's Gateway project and Teresen's various TMX projects may both have a role in future new market development. Yet, one must be cognizant that more significant expansions and other initiatives will be entirely dependent upon the desires of a proposed system's shippers. Additionally, the attractiveness of these potential investments has attracted considerable attention and increased project competition (consider TransCanada's recent Keystone proposal - for greater details please refer to our 9 February 2005 note "*Keystone proposal*"). Despite some significant concerns (i.e. rising steel costs and significant capital expenditure programs being upwardly revised), over the longer term, the trend toward crude market diversification is likely to continue. That trend is likely to be economically beneficial for companies exposed to the oil sands.

Greater crude dispersion necessary

Shippers play a lead role

Gas distribution growth

As with many regulated utilities, Terasen's natural gas distribution utility has suffered from a declining yield curve that has translated into lower allowed regulated returns. Yet, there have been some positive trends and announcements for the company's natural gas distribution business. For instance, on 16 February the British Columbia Utilities Commission approved a C$100 million liquefied natural gas storage facility near Nanaimo, British Colubmia that would be used for peak shaving and load management activities (note this facility as with Terasen's existing LNG facility would not be used for imports). One of the driving factors for this project is the need for additional generation capacity on Vancouver Island. Regarding that issue, the BCUC approved an energy purchase contract between BC Hydro and Duke Point Power LP for a 262MW natural gas power plant That generation facility and the LNG proposal may benefit Terasen in a number of ways, including: (1) increased distribution rate base; (2)

Incremental distribution growth on Vancouver Island driven by power plant development increased system throughput; and (3) gradual transmission system expansion. We view this prospective plant and other prospective projects within the province as beneficial for Teresen's utility business. Additionally, recent electricity rate increases within British Columbia are slowly improving the relative competitiveness of natural gas for home heating versus baseboard electric.

Valuation

In our view, the company faces relatively good prospects in its core business areas and continued oil sands growth, combined with new market access issues, underpin a significant portion of Terasen's future growth. Additionally, a number of marco factors, are likely to be supportive of the company's existing valuation, including: currency fundamentals; the Canadian interest rate environment; and, fund flows (for greater details please refer to our 14 January 2005 research report "*Rise of the loonie?*"). Clearly, a number of positives exist for the stock. However, we believe a portion of future growth is priced within the stock at this point. We continue to utilize multiple valuation methods to obtain our C$28.00 12-month target price, including: 17.5x P/E multiple on our 2006 earnings estimate; a projected dividend yield of 3.2%; and, a dividend yield spread of 180 bps. We retain our Neutral 1 rating.

■ Terasen Inc.

Terasen is a traditional regulated natural gas distribution utility serving several market areas in the Province of British Columbia. The company also possesses a substantial liquids pipelines business that provides direct access into three separate Petroleum Administration Defence Districts (PADD) for Alberta crude products.

■ Statement of Risk

Competitive pipeline expansions may significantly affect volume throughput and, therefore, earnings. Additionally, Terasen's business is exposed to a number of specific risks, including: throughput; weather; interest rates; and, competitive energy sources. Finally, one should never underestimate the power of the regulator in any regulated business.

IDA Policy No. 11, Standard 13 Disclosure: The Analyst named in this report has viewed the issuer's head office location within the last 12 months.u

■ Analyst Certification

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UBS Investment Research: Global Equity Ratings Definitions and Allocations

UBS rating	Definition	UBS rating	Definition	Rating category	Coverage[1]	IB services[2]
Buy 1	FSR is > 10% above the MRA, higher degree of predictability	**Buy 2**	FSR is > 10% above the MRA, lower degree of predictability	**Buy**	36%	32%
Neutral 1	FSR is between -10% and 10% of the MRA, higher degree of predictability	**Neutral 2**	FSR is between -10% and 10% of the MRA, lower degree of predictability	**Hold/Neutral**	53%	35%
Reduce 1	FSR is > 10% below the MRA, higher degree of predictability	**Reduce 2**	FSR is > 10% below the MRA, lower degree of predictability	**Sell**	11%	29%

1: Percentage of companies under coverage globally within this rating category.

2: Percentage of companies within this rating category for which investment banking (IB) services were provided within the past 12 months.

Source: UBS; as of 31 December 2004.

KEY DEFINITIONS

Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months.
Market Return Assumption (MRA) is defined as the one-year local market interest rate plus 5% (an approximation of the equity risk premium).
Predictability Level The predictability level indicates an analyst's conviction in the FSR. A predictability level of '1' means that the analyst's estimate of FSR is in the middle of a narrower, or smaller, range of possibilities. A predictability level of '2' means that the analyst's estimate of FSR is in the middle of a broader, or larger, range of possibilities.
Under Review (UR) Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation.
Rating/Return Divergence (RRD) This qualifier is automatically appended to the rating when stock price movement has caused the prevailing rating to differ from that which would be assigned according to the rating system and will be removed when there is no longer a divergence, either through market movement or analyst intervention.

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UK and European Investment Fund ratings and definitions are: Buy: Positive on factors such as structure, management, performance record, discount; Neutral: Neutral on factors such as structure, management, performance record, discount; Reduce: Negative on factors such as structure, management, performance record, discount.
Core Banding Exceptions (CBE): Exceptions to the standard +/-10% bands may be granted by the Investment Review Committee (IRC). Factors considered by the IRC include the stock's volatility and the credit spread of the respective company's debt. As a result, stocks deemed to be very high or low risk may be subject to higher or lower bands as they relate to the rating. When such exceptions apply, they will be identified in the Companies Mentioned table in the relevant research piece.

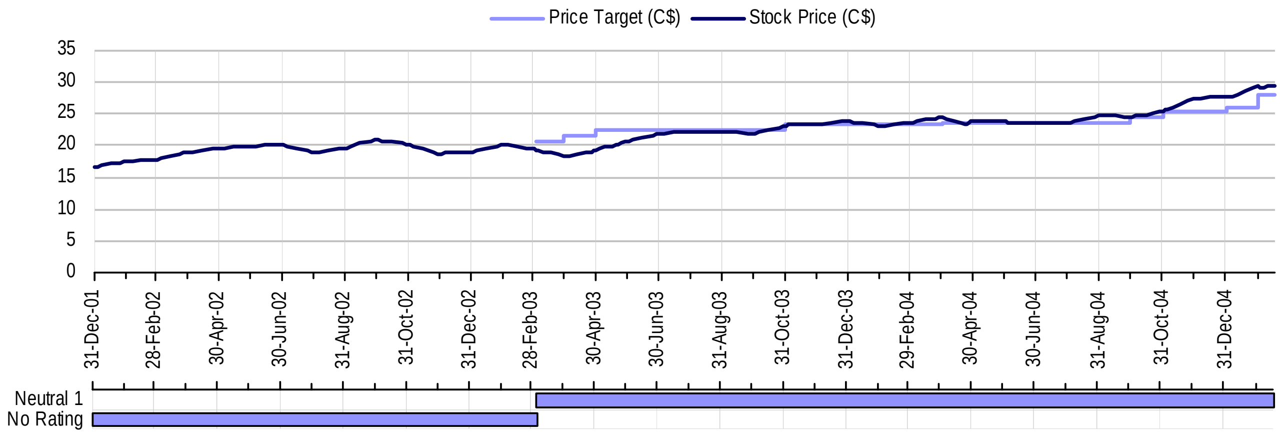
Companies mentioned

Company Name	Reuters	Rating	Price
Terasen Inc.	TER.TO	Neutral 1	C$29.45

Price(s) as of 16 February 2005. Source: UBS.

Unless otherwise indicated, please refer to the Valuation and Risk sections within the body of this report.

Terasen Inc. (C$)



Source: UBS; as of 16 February 2005.

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Head Office: UBS Limited, 1 Finsbury Avenue, London, EC2M 2PP, UK Phone: +44-20-7567 8000

Local Office: UBS Securities Canada Inc, BCE Place, Suite 4100, Bay Street Suite, 161 Bay Street, Toronto, Ontario M5J 2S1 Phone: +1-416-364 3293

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Terasen Inc.

Less than full pipeline

■ EPS falls short

Terasen reported Q1 2005 EPS of C$0.63, which fell short of our C$0.68 estimate and the Street's view of C$0.71. Yet, two notable issues skewed these results: 1) an after tax mark-to-market gain of C$0.02/sh; and, 2) low petroleum throughput which resulted in a drag on earnings of C$0.05/sh.

■ Weak volumes due to oil supply disruption

Several production outages in the Alberta oil sands coupled with certain refinery outages resulted in lower throughput volumes on both the Trans Mountain and Express Systems. When compared to Q1 of last year, volumes on the Trans Mountain system were down nearly 30%, while volumes on the Express system were down 2.6%.

■ Expect short term weakness; opportunities remain ahead

While Terasen faces a number of somewhat compelling opportunities, we believe only a seletion of these prospects will come to fruition. Additionally, we believe the progression into a much larger and potentially higher earning and returning company will take some time to develop.

■ Valuation: C$28.00 12-month target price

We continue to utilize multiple valuation methods to obtain our C$28.00 12-month target price, including: a 17.5x P/E multiple on our 2006 earnings estimate; a projected dividend yield of 3.2%; and, a dividend yield spread of 180 bps. We retain our Neutral 1 rating.

Highlights (C$m)	12/03	12/04	12/05E	12/06E	12/07E
Revenues	1,848	1,957	2,020	2,074	2,163
EBIT	338	377	393	397	432
Net income (UBS)	111	156	161	172	179
EPS (UBS, C$)	1.27	1.41	1.50	1.60	1.67
Net DPS (UBS, C$)	0.76	0.82	0.90	0.93	0.98
Profitability & Valuation	**5-yr hist. av.**	**12/04**	**12/05E**	**12/06E**	**12/07E**
EBIT margin %	-	19.3	19.5	19.2	20.0
ROIC (EBIT) %	-	9.4	10.1	10.1	11.0
EV/EBITDA x	-	10.3	10.8	10.8	10.0
PE (UBS) x	-	17.3	18.3	17.1	16.4
Dividend yield %	-	3.4	3.3	3.4	3.6

Source: Company accounts, Thomson Financial, UBS estimates. UBS adjusted EPS is stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of C$27.45 on 04 May 2005 19:21 EDT

Andrew M. Kuske
Analyst
andrew.kuske@ubs.com
+1-416-814 3663

Global Equity Research

Americas

Gas Utilities

Rating	Neutral 1 *Unchanged*
Price target	C$28.00/US$22.33 *Unchanged*
Price	C$27.45/US$22.02

RIC: TER.TO BBG: TER CN

4 May 2005

Trading data (local/US$)

52-wk. range	C$29.71-22.05/US$24.10-16.00
Market cap.	C$2.88bn/US$2.32bn
Shares o/s	105m (COM)
Free float	100%
Avg. daily volume ('000)	143
Avg. daily value (C$m)	4.0

Balance sheet data 12/05E

Shareholders' equity	C$1.49bn
P/BV (UBS)	2.0x
Net cash (debt)	(C$3.07bn)

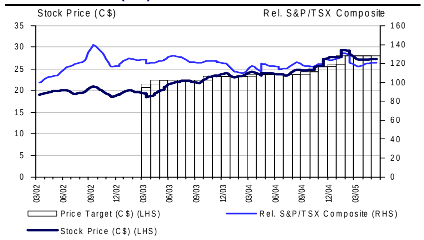
Forecast returns

Forecast price appreciation	+2.0%
Forecast dividend yield	3.3%
Forecast stock return	+5.3%
Market return assumption	7.8%
Forecast excess return	-2.5%

EPS (UBS, C$)

	12/05E		12/04
	UBS	Cons.	Actual
Q1	0.63	*0.64*	0.77
Q2E	0.22	*0.20*	0.10
Q3E	0.13	*0.09*	(0.01)
Q4E	0.52	*0.56*	0.51
12/05E	1.50	*1.49*	
12/06E	1.60	*1.56*	

Performance (C$)



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ANALYST CERTIFICATION AND REQUIRED DISCLOSURES BEGIN ON PAGE 6

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Terasen reported Q1 2005 EPS of C$0.63, which fell short of our C$0.68 estimate and the Street's view of C$0.71. Yet, two notable issues skewed these results: 1) an after tax mark-to-market gain of C$0.02/sh in the "other activities" segment; and, 2) low petroleum throughput which resulted in a drag on earnings in the amount of C$0.05/sh. Several production outages in the Alberta oil sands coupled with certain refinery outages resulted in lower throughput on both the Trans Mountain and the Express Systems. When compared to Q1 of last year, volumes on the Trans Mountain system were down nearly 30%, while volumes on the Express system were down 2.6%. We continue to believe Terasen faces relatively good prospects in its core business areas. In our view, strong crude fundamentals, continued oil sands growth prospects and new market access issues underpin a significant portion of Terasen's future growth. This research note is divided into three categories: (1) results; (2) going forward; and, (3) valuation.

Results

Selected issues affected pipeline volumes

Terasen reported Q1 2005 EPS of C$0.63, which fell short of our C$0.68 estimate and the Street's view of C$0.71. Yet, two notable issues skewed these results: 1) an after tax mark-to-market gain of C$0.02/sh in the "other activities" segment; and, 2) low petroleum throughput which resulted in a drag on earnings in the amount of C$0.05/sh. Several production outages in the Alberta oil sands coupled with certain refinery outages resulted in lower throughput on both the Trans Mountain and the Express Systems. When compared to Q1 of last year, volumes on the Trans Mountain system were down nearly 30%, while volumes on the Express system were down 2.6%. We continue to believe Terasen faces relatively good prospects in its core business areas. In our view, strong crude fundamentals, continued oil sands growth prospects and new market access issues underpin a significant portion of Terasen's future growth. Our segmented analysis appears below.

Natural gas distribution

Moderately disappointing results

While total volumes in the natural gas segment were nearly flat at 75.1PJ in Q1 2005 compared to 75.4PJ during the same quarter last year, earnings in this segment grew 1.8% from C$54.7m in Q1 2004 to C$55.7m in Q1 2005. This performance was partially attributable to operating efficiencies and customer growth. Selected comparative data appears in the table below.

Table 1: Natural gas distribution data points

	Q1 2005	Q1 2004	Q4 2004	Chg (%) y-o-y	Chg (%) seq
Earnings (C$millions)					
Terasen Gas	49.0	48.0	36.2	2.1%	35.4%
TGVI	6.7	6.7	6.4	0.0%	4.7%
Total	55.7	54.7	42.6	1.8%	30.8%
Number of Customers	878,560	862,631		1.8%	
Volumes (petajoules)					
Sales Volumes	48.8	49.3	41.1	-1.0%	18.7%
Transportation volumes	21.6	21.9	19.6	-1.4%	10.2%
Throughput	4.7	4.2	5.5	11.9%	-14.5%
	75.1	75.4	66.2	-0.4%	13.4%

Source: Company reports and UBS

Additional pertinent information includes: (a) During Q1 2005 the customer base grew by roughly 4%, which is roughly equivalent to the customer growth experienced during Q1 2004; (b) operations and maintenance costs increased by a very modest 0.8% compared to the same quarter last year; and, (c) financing costs declined by roughly 2% in Q1 2005.

Customer growth continues

Petroleum transportation

Temporary production outages in the Alberta oil sands coupled with certain refinery outages resulted in lower throughput volumes in both the Trans Mountain system and the Express System. When compared to Q1 of last year, volumes on the Trans Mountain system were down nearly 30%, while volumes on the Express system were down 2.6%.

Substantial volume declines are unlikely to be ongoing

Table 2: Petroleum transportation data points

	Q1 2005	Q1 2004	Q4 2004	Chg (%) y-o-y	Chg (%) seq
Earnings (C$millions)					
Trans Mountain	5.4	10.4	11.2	-48.1%	-51.8%
Express System	3.7	4.0	4.9	-7.5%	-24.5%
Corridor	3.6	3.9	3.8	-7.7%	-5.3%
Total	12.7	18.3	19.9	-30.6%	-36.2%
Volumes (b/d)					
Trans Mtn Cdn mainline	170,000	240,400	239,100	-29.3%	-28.9%
Trans Mtn US mainline	44,500	93,300	89,300	-52.3%	-50.2%
Express System	166,900	171,300	175,400	-2.6%	-4.8%
Total	381,400	505,000	503,800	-24.5%	-24.3%

Source: Company reports and UBS

The volume declines were largely related to production problems and several oil sands projects (eg: Suncor Energy) coupled with selected refinery outages. Naturally, risks exist in the pipeline transmission business, however, we consider the confluence of activities in Q1 to be somewhat rare. Yet, we are considering them to be of an operating nature, rather than one-time.

Water and utility services

Reflecting the contribution of Fairbanks acquisition, among other factors, net income improved to C$0.8m in Q1 2005 compared to C$0.0m in Q1 2004.

Other activities

Based on reported figures, year-over-year performance in this segment improved, with a loss of C$2.9m in Q1 2005 compared to a loss of C$5.1m in Q1 2004. However, after extracting the effect of mark-to-market gains in each of the quarters being compared, losses in this segment during Q1 2005 were C$5.5 compared to a loss of C$6.8m during the same quarter last year.

Going forward

We believe Terasen investors, whether existing or prospective, should be aware of three major issues: (1) Oil sands affection; (2) New market development; and, (3) Gas distribution growth. Each of these will be addressed in greater detail below.

Oil sands affection?

Increased affection towards oil sands names

Fundamentally, we have viewed the oil sands as a unique investment opportunity that may provide relatively visible growth over an extended period of time. Moreover, we regard pipelines that provide takeaway capacity from the oil sands as being similarly unique. The ongoing strength in global oil prices has led to an increased amount of investor attention being directed towards oil sands related companies, including Enbridge and Terasen. As several of the large oil and gas companies are on the verge of embarking upon significant capital programs for continued or new oil sands development, we believe a number of investors are building significant expectations into an indirect method of playing oil sands developments: the liquids pipeline companies. Notably, as discussed on the Terasen conference call, the significant oil sands expansion project recently filed by Shell Canada for its Muskeg River mine is likely to provide opportunities for the Corridor Pipeline. In our view, the long-term and highly visible growth associated with the oil sands has moderately boosted recent valuations. Yet, as per capital expenditure theory, we are likely to become far less bullish when the major capital programs commence. Prior to that time, we continue to believe that “oil sands affection” along with a number of other factors are likely to support rather robust valuations for selected oil sands pipeline plays.

Go west, young man, go west!

Greater crude dispersion necessary

In our report titled "*Go west, young man, go west!*" (dated 27 January 2005), we have outlined a number of issues related to new market development for western Canadian crude and related products. Much of the thrust for new market development arises from the necessity of avoiding a significant market saturation of Canadian crudes (including heavy and synthetic) in any one market region. In our view, new market development is necessary and Terasen is likely to benefit from such market diversification. We continue to believe a number of market areas will be attractive and necessary for Canadian based producers. By way of corollary, the pipeline and appropriate transportation network serving those markets will be equally important. Potential developments such as Enbridge's Gateway project and Teresen's various TMX projects may both have a role in future new market development. At this time, we are seeing substantial evidence that crude diversification strategies are truly taking hold with the recent National Energy Board decision relating to the Spearhead and Corsicana pipelines. Additionally, with the relatively recent announcement regarding the Enbridge-PetroChina Memorandum of Understanding about the Gateway Pipeline provides further evidence of the forces of supply push and demand pull coming into balance (for greater details please refer to our 14 April 2005 research note "*When east meets west*"). Over the longer term, the trend toward crude market diversification is likely to continue. That trend is likely to be economically beneficial for companies exposed to the oil sands.

Shippers play a lead role

Gas distribution growth

As compared to the company's Petroleum Transportation business, we believe Terasen will have a lower growth profile in its natural gas distribution utility. In our view, there are a number of issues of which one should be cognizant, including:

Incremental distribution growth on Vancouver Island driven by power plant development

- The British Columbia Utilities Commission approved a C$100m Terasen peak shaving liquefied natural gas storage facility near Nanaimo, British Columbia;
- One of the driving factors for the LNG facility is the need to help fuel proposed additional natural gas fired generation capacity on Vancouver Island; and,
- Weaker Pacific Northwest hydrology combined with electricity rate increases within British Columbia are slowly improving the relative competitiveness of natural gas for home heating versus that of baseboard electric.

Valuation

In our view, this quarter's earnings were a bit of a disappointment. Yet, over the longer-term, we believe Terasen faces relatively good prospects in its core business areas and continued oil sands growth, combined with new market access issues, underpin a significant portion of the company's future growth. We continue to utilize multiple valuation methods to obtain our C$28.00 12-month target price, including: 17.5x P/E multiple on our 2006 earnings estimate; a projected dividend yield of 3.2%; and, a dividend yield spread of 180 bps. We retain our Neutral 1 rating.

■ Terasen Inc.

Terasen is a traditional regulated natural gas distribution utility serving several market areas in the Province of British Columbia. The company also possesses a substantial liquids pipelines business that provides direct access into three separate Petroleum Administration Defence Districts (PADD) for Alberta crude products.

■ Statement of Risk

Competitive pipeline expansions may significantly affect volume throughput and, therefore, earnings. Additionally, Terasen's business is exposed to a number of specific risks, including: throughput; weather; interest rates; and, competitive energy sources. Finally, one should never underestimate the power of the regulator in any regulated business.

■ Analyst Certification

Each research analyst primarily responsible for the content of this research report, in whole or in part, certifies that with respect to each security or issuer that the analyst covered in this report: (1) all of the views expressed accurately reflect his or her personal views about those securities or issuers; and (2) no part of his or her compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by that research analyst in the research report.

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Buy 1	FSR is > 10% above the MRA, higher degree of predictability	**Buy 2**	FSR is > 10% above the MRA, lower degree of predictability	**Buy**	37%	30%
Neutral 1	FSR is between -10% and 10% of the MRA, higher degree of predictability	**Neutral 2**	FSR is between -10% and 10% of the MRA, lower degree of predictability	**Hold/Neutral**	52%	32%
Reduce 1	FSR is > 10% below the MRA, higher degree of predictability	**Reduce 2**	FSR is > 10% below the MRA, lower degree of predictability	**Sell**	11%	25%

1: Percentage of companies under coverage globally within this rating category.

2: Percentage of companies within this rating category for which investment banking (IB) services were provided within the past 12 months.

Source: UBS; as of 31 March 2005.

KEY DEFINITIONS

Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months.
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Under Review (UR) Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation.
Rating/Return Divergence (RRD) This qualifier is automatically appended to the rating when stock price movement has caused the prevailing rating to differ from that which would be assigned according to the rating system and will be removed when there is no longer a divergence, either through market movement or analyst intervention.

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UK and European Investment Fund ratings and definitions are: Buy: Positive on factors such as structure, management, performance record, discount; Neutral: Neutral on factors such as structure, management, performance record, discount; Reduce: Negative on factors such as structure, management, performance record, discount.
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Companies mentioned

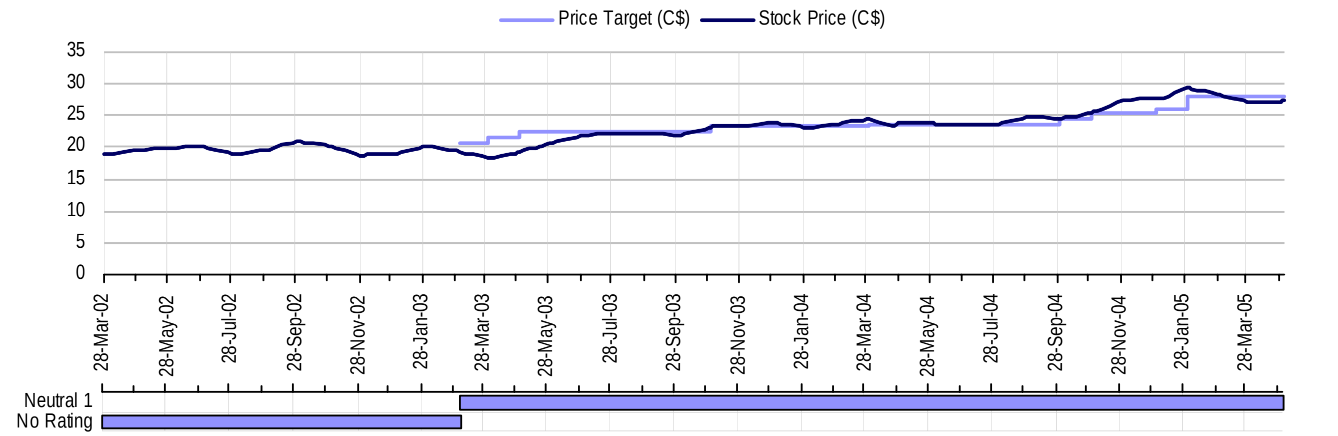
Company Name	Reuters	Rating	Price	Price date/time
Terasen Inc.	TER.TO	Neutral 1	C$27.39	03 May 2005 19:35 EDT

Source: UBS. EDT: Eastern daylight time.

The analyst responsible for this report has reviewed the material operations of the issuer and/or met with senior management.

Unless otherwise indicated, please refer to the Valuation and Risk sections within the body of this report.

Terasen Inc. (C$)



Source: UBS; as of 3 May 2005.

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Global Equity Research

Americas

Gas Utilities

UBS Investment Research

Terasen Inc.

Rating	Neutral 1*
	Unchanged
Price target	C$28.00/US$23.03
	Unchanged
Price	C$30.08/US$25.00

RIC: TER.TO BBG: TER CN

12 July 2005

Pumping up Trans Mountain

■ Modestly upping capacity

Terasen has filed an application with the National Energy Board (NEB) to increase the capacity of its Trans Mountain system by 35,000 bpd. If approved, the expansion will cost C$210 million and will come online in Q1 2007.

■ Phase one of many

The expansion, which involves building new as well as upgrading existing pumpstations, is the first phase in potentially larger Trans Mountain expansions to follow. The next phase involves gaining shipper support for the construction of a 30-inch pipeline loop between Hinton, Alberta and Valemount, B.C.

■ Short-term weakness; opportunities remain ahead

While Terasen faces a number of somewhat compelling opportunities, we believe only a seletion of these prospects will come to fruition. Additionally, we believe the progression into a much larger and potentially higher earning and returning company will take some time to develop.

■ Valuation: C$28.00 12-month target price

We continue to utilize multiple valuation methods to obtain our C$28.00 12-month target price, including: a 17.5x P/E multiple on our 2006 earnings estimate; a projected dividend yield of 3.3%; and, a dividend yield spread of 170 bps. We rate the stock Neutral 1 (RRD).

Highlights (C$m)	12/03	12/04	12/05E	12/06E	12/07E
Revenues	1,848	1,957	2,020	2,074	2,163
EBIT	338	377	393	397	432
Net income (UBS)	111	156	161	172	179
EPS (UBS, C$)	1.27	1.41	1.50	1.60	1.67
Net DPS (UBS, C$)	0.76	0.82	0.90	0.93	0.98

Profitability & Valuation	5-yr hist. av.	12/04	12/05E	12/06E	12/07E
EBIT margin %	-	19.3	19.5	19.2	20.0
ROIC (EBIT) %	-	9.4	10.1	10.1	11.0
EV/EBITDA x	-	10.3	11.3	11.3	10.5
PE (UBS) x	-	17.3	20.1	18.8	18.0
Dividend yield %	-	3.4	3.0	3.1	3.3

Source: Company accounts, Thomson Financial, UBS estimates. UBS adjusted EPS is stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of C$30.08 on 12 Jul 2005 17:21 EDT

Andrew M. Kuske
Analyst
andrew.kuske@ubs.com
+1-416-814 3663

Trading data (local/US$)

52-wk. range	C$30.08-23.15/US$25.00-17.36
Market cap.	C$3.17bn/US$2.63bn
Shares o/s	105m (COM)
Free float	100%
Avg. daily volume ('000)	127
Avg. daily value (C$m)	3.6

Balance sheet data 12/05E

Shareholders' equity	C$1.49bn
P/BV (UBS)	2.2x
Net cash (debt)	(C$3.07bn)

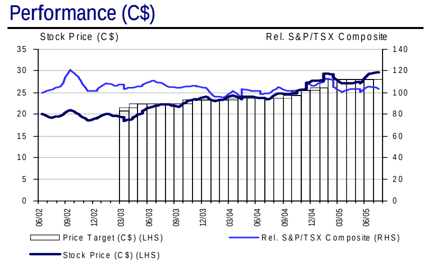
Forecast returns

Forecast price appreciation	-6.9%
Forecast dividend yield	3.0%
Forecast stock return	-3.9%
Market return assumption	7.9%
Forecast excess return	-11.8%

EPS (UBS, C$)

	12/05E		12/04
	UBS	Cons.	Actual
Q1	0.63	*0.60*	0.77
Q2E	0.22	*0.21*	0.10
Q3E	0.13	*0.12*	(0.01)
Q4E	0.52	*0.55*	0.51
12/05E	1.50	*1.49*	
12/06E	1.60	*1.56*	

Performance (C$)



Source: UBS

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*Rating/return divergence; See page 3

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Buy 1	FSR is > 10% above the MRA, higher degree of predictability	**Buy 2**	FSR is > 10% above the MRA, lower degree of predictability	**Buy**	40%	41%
Neutral 1	FSR is between -10% and 10% of the MRA, higher degree of predictability	**Neutral 2**	FSR is between -10% and 10% of the MRA, lower degree of predictability	**Hold/Neutral**	49%	43%
Reduce 1	FSR is > 10% below the MRA, higher degree of predictability	**Reduce 2**	FSR is > 10% below the MRA, lower degree of predictability	**Sell**	11%	35%

1: Percentage of companies under coverage globally within this rating category.

2: Percentage of companies within this rating category for which investment banking (IB) services were provided within the past 12 months.

Source: UBS; as of 30 June 2005.

KEY DEFINITIONS

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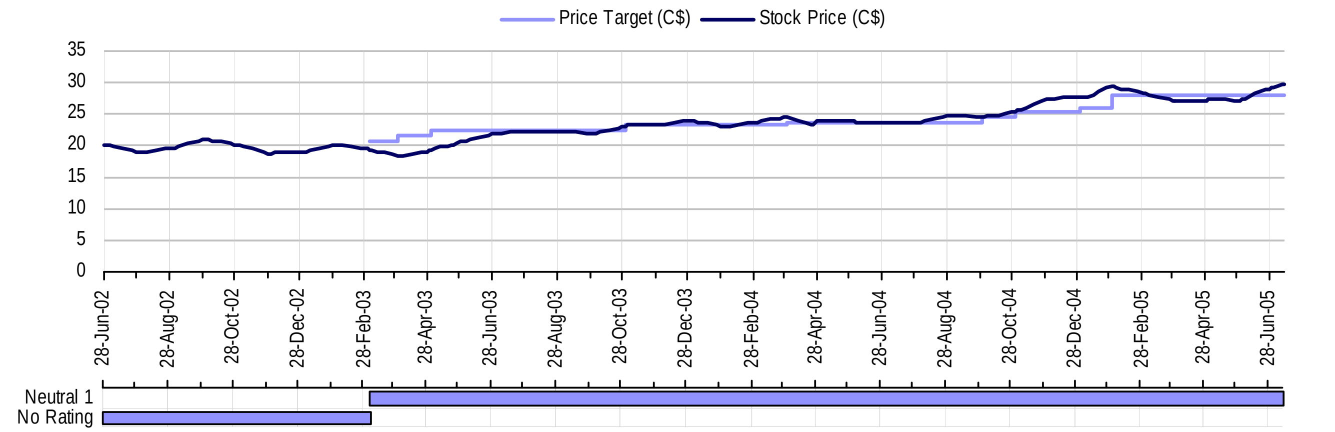
Companies mentioned

Company Name	Reuters	Rating	Price	Price date/time
Terasen Inc.	TER.TO	Neutral 1 (RRD)	C$29.78	11 Jul 2005 19:37 EDT

Source: UBS. EDT: Eastern daylight time.

Unless otherwise indicated, please refer to the Valuation and Risk sections within the body of this report.

Terasen Inc. (C$)



Source: UBS; as of 11 July 2005.

Note: On October 13, 2003, UBS adopted new definition criteria for its rating system. (See 'UBS Investment Research: Global Equity Ratings Definitions and Allocations' table for details.) Between January 11 and October 12, 2003, the UBS ratings and their definitions were: Buy 1: Excess return potential > 15%, smaller range around price target; Buy 2: Excess return potential > 15%, larger range around price target; Neutral 1: Excess return potential between -15% and 15%, smaller range around price target; Neutral 2: Excess return potential between -15% and 15%, larger range around price target; Reduce 1: Excess return potential < -15%, smaller range around price target; Reduce 2: Excess return potential < -15%, larger range around price target. Prior to January 11, 2003, the UBS ratings and definitions were: Strong Buy: Greater than 20% excess return potential, high degree of confidence; Buy: Positive excess return potential; Hold: Low excess return potential, low degree of confidence; Reduce: Negative excess return potential; Sell: Greater than 20% negative excess return potential, high degree of confidence. Under both ratings systems, excess return is defined as the difference between the FSR and the one-year local market interest rate.

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Attachment 86.1

Rating Agency Presentation

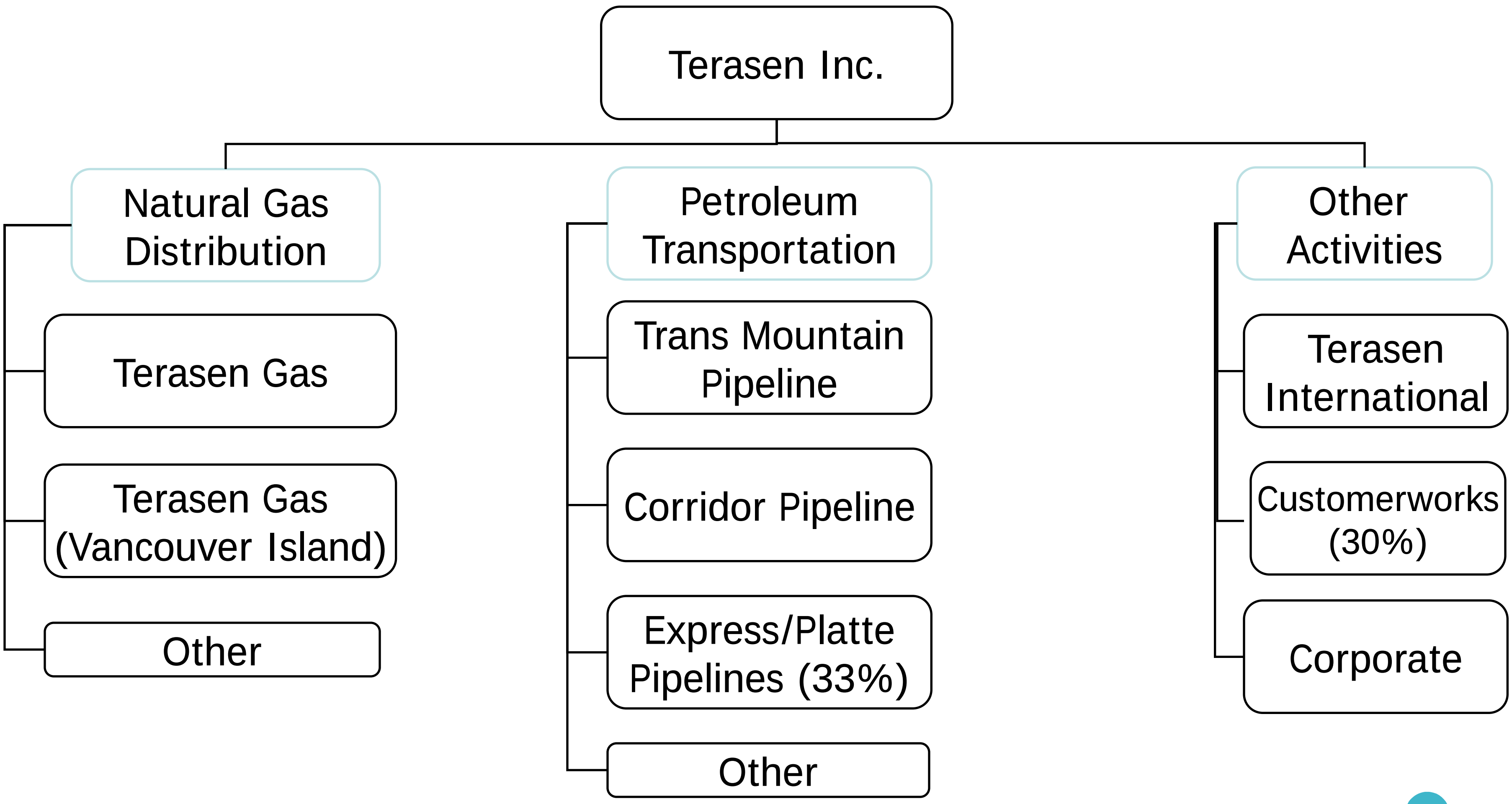
June 2006

Terasen

Presentation Overview

- Corporate Overview
- Gas Distribution
- Pipelines
- Financing Plans

Corporate Structure



Management

Park Shaper
President

Kim Dang
VP & CFO

Joe Listengart
VP, General Counsel
& Secretary

David Kinder
Vice President

Roger Dall'Antonia
VP, Treasurer

Randy Jespersen
President,
Terasen Gas

Ian Anderson
President,
Kinder Morgan Canada

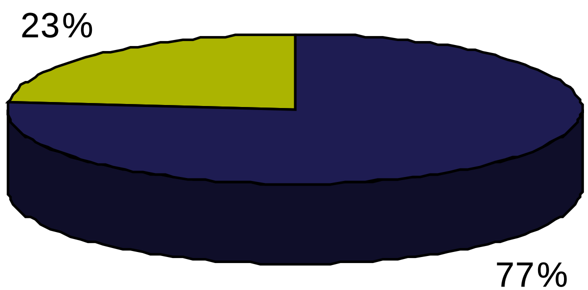
Area of Operations

Petroleum Transportation

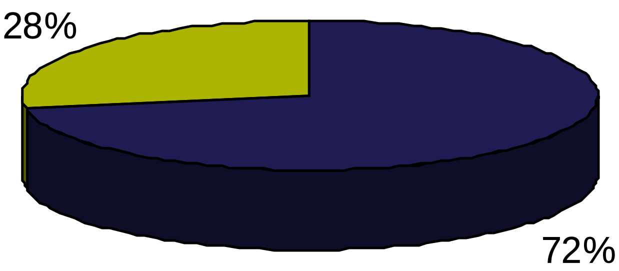
Natural Gas Distribution

Corporate Overview

Operating Income: $358 million
(12 months ended December 31, 2005)



Assets: $5,054 million
(at December 31, 2005)



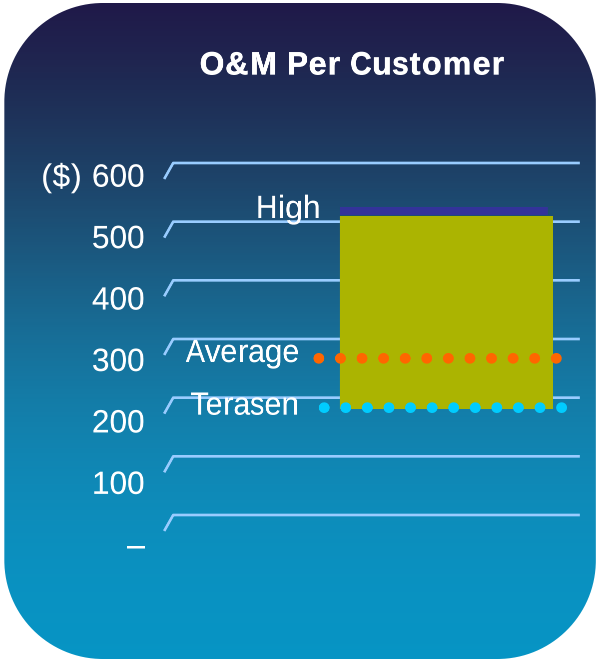
Natural Gas Distribution **Petroleum Transportation**

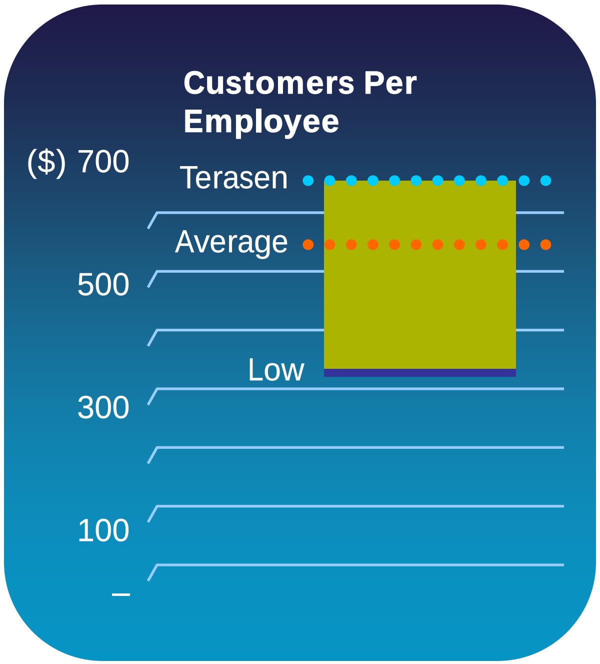
Terasen Gas

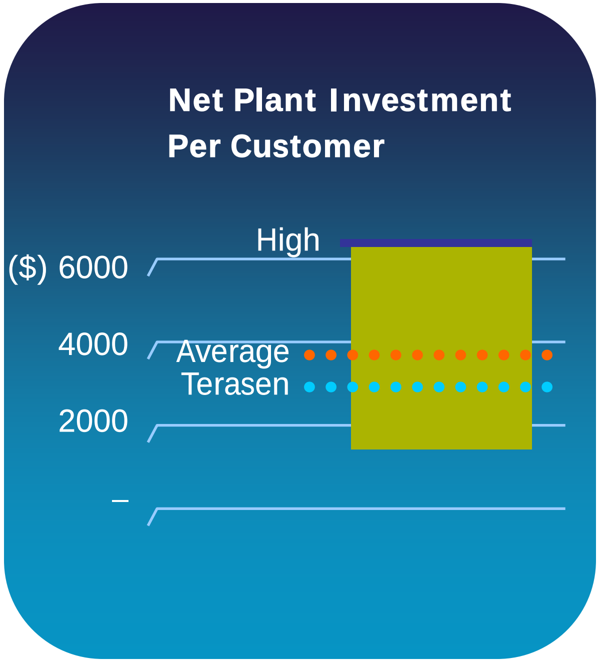
2005 Highlights

- Continued growth in rate base for both TGI and TGVI
- TGI customer additions of 12,613 in 2005 versus 11,750 in 2004
- TGVI customer additions of 4,354 in 2005 versus 4,233 in 2004
- Net income, once adjusted for KMI acquisition costs, higher as rate base growth and operating efficiencies offset lower allowed ROE

Operating Efficiency







Source: LSM Consulting

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Price Competitiveness

- Increases in the market price of natural gas, combined with a government-mandated electricity price freeze, have eroded the historical advantage over electricity
- Terasen Gas maintains an active price risk management program (on behalf of customers) which mitigates this risk
- BC Hydro has been supportive of demand-side management initiatives to encourage efficient energy use decisions
- BC Hydro is seeking price increase of approximately 4.6%

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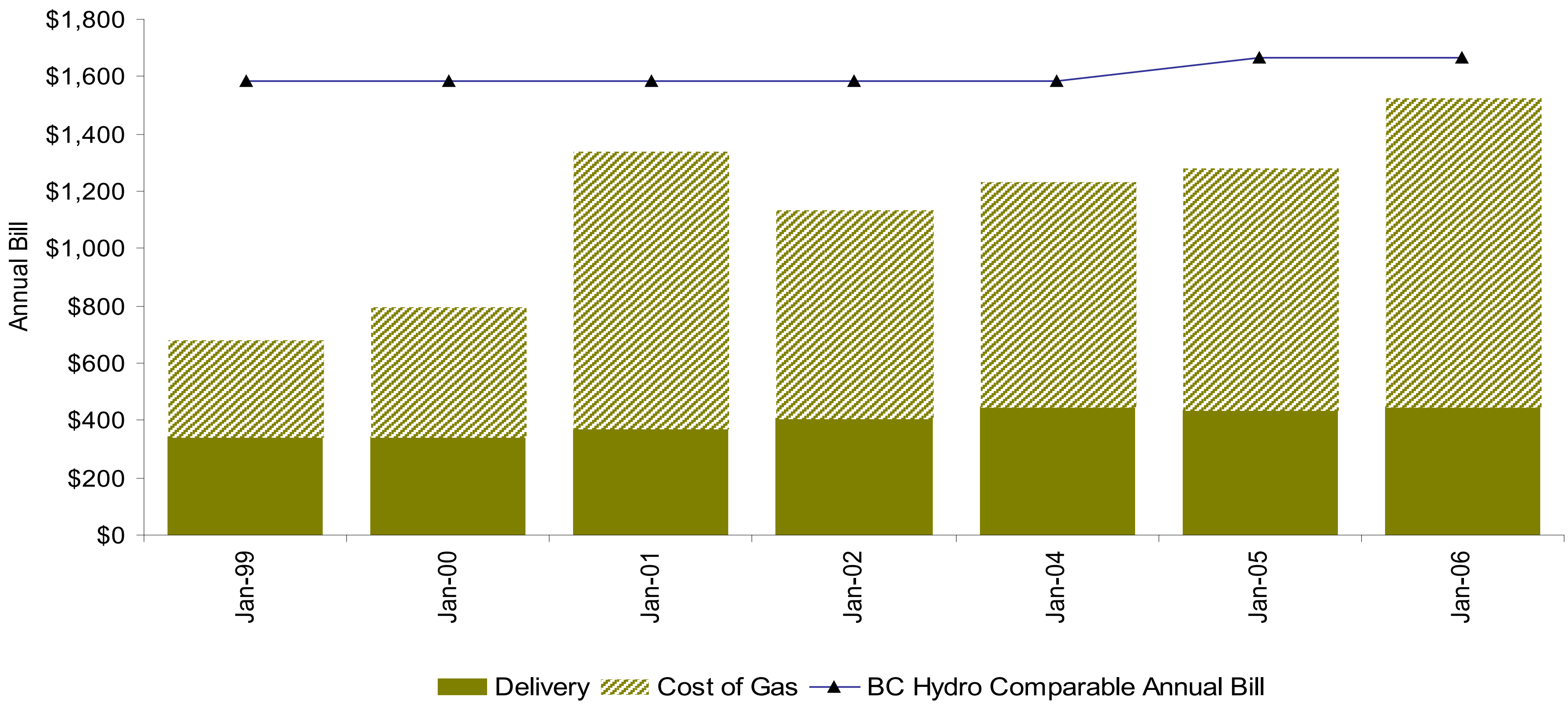
Price Competitiveness

Lower Mainland Residential Annual Bill History - Gas vs. Electric Comparison
Terasen Gas Delivery and Commodity Charges



Regulatory Arrangements

- 2004-2007 PBR in place for Terasen Gas
  - O&M and capital cost incentives, 50/50 sharing
  - Numerous deferral accounts
- 2006-2007 PBR in place for TGVI
  - O&M incentives, no sharing
  - Comprehensive deferral arrangements through Revenue Deficiency Deferral Account
  - Two-year extension aligns regulatory calendar with Terasen Gas

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Regulatory Arrangements

- ROE and Capital Structure hearing Q3 2005
- BCUC decision rendered March 2006
  - Equity component for TGI 35% from 33%
  - Equity component for TGVI 40% from 35%
  - Amended ROE formula
    - 3.90% premium over forecast 30 year GoC yield
    - TGVI risk premium 70 bps over TGI premium
    - Risk premium adjusted by 75% of change in forecast yield year over year
  - Effective retroactive to Jan. 1, 2006

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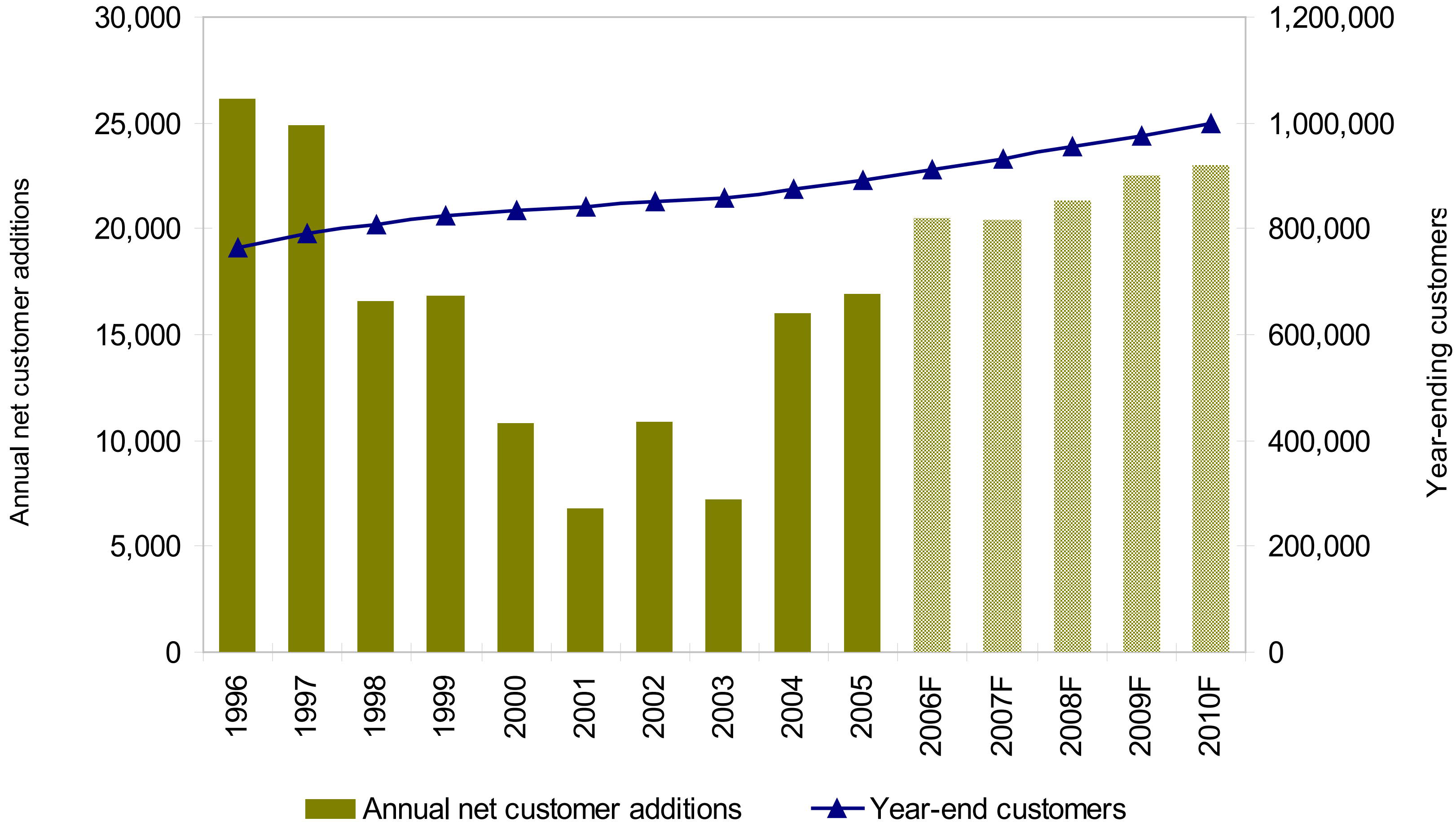
Terasen Gas - Outlook

- Successful efforts to improve operating efficiency in the past has limited the scope for future efficiencies
- Focus will be on increasing customer capture rates
  - Target of 1 million gas customers in 2010 (up from 891,000 currently)
  - Opportunity to improve capture rates for multi-family housing starts
  - Regional economy remains very strong

Customer Growth



LNG Expansion

- BCUC previously approved $100 million Vancouver Island LNG Project subject to Duke Point power plant proceeding
- LNG Project subsequently cancelled when BC Hydro withdrew from the Duke Point project
- TGI and TGVI jointly reconsidering a LNG storage facility, located on Vancouver Island
  - Possible CPCN filing Q4 2006
  - In-service in 2010
  - Approximate capital cost of $140 million

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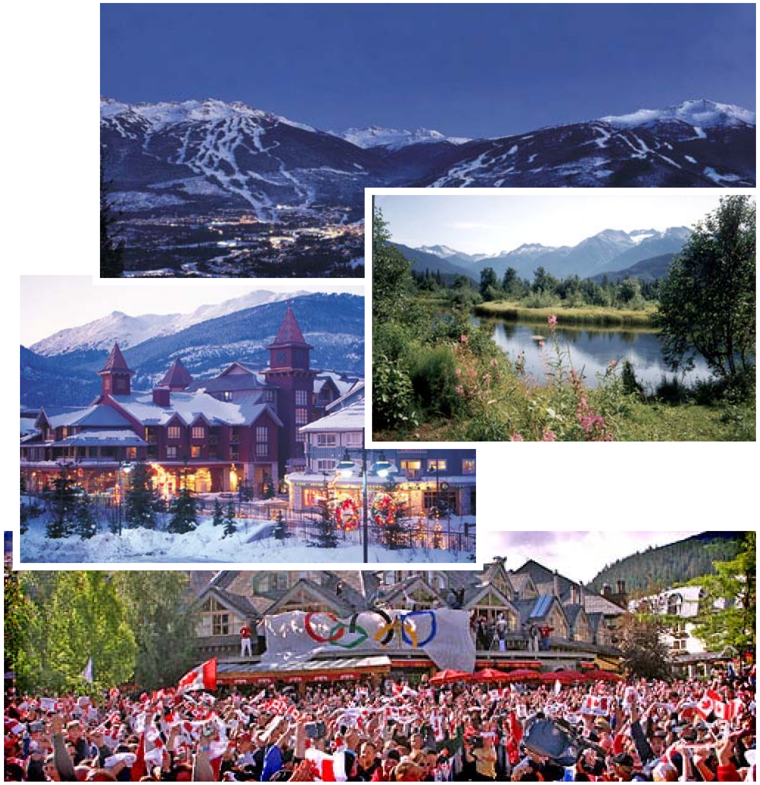
Growth – Whistler

- Working with the Resort Municipality of Whistler to develop a Sustainable Energy Strategy
  - Establish a hybrid gas/GSHP energy utility
  - Construct a natural gas pipeline from Squamish to Whistler
  - Develop renewable district energy systems or other sustainable options
- Estimated pipeline cost – $43 million
- Model for integrating natural gas with renewable energy sources



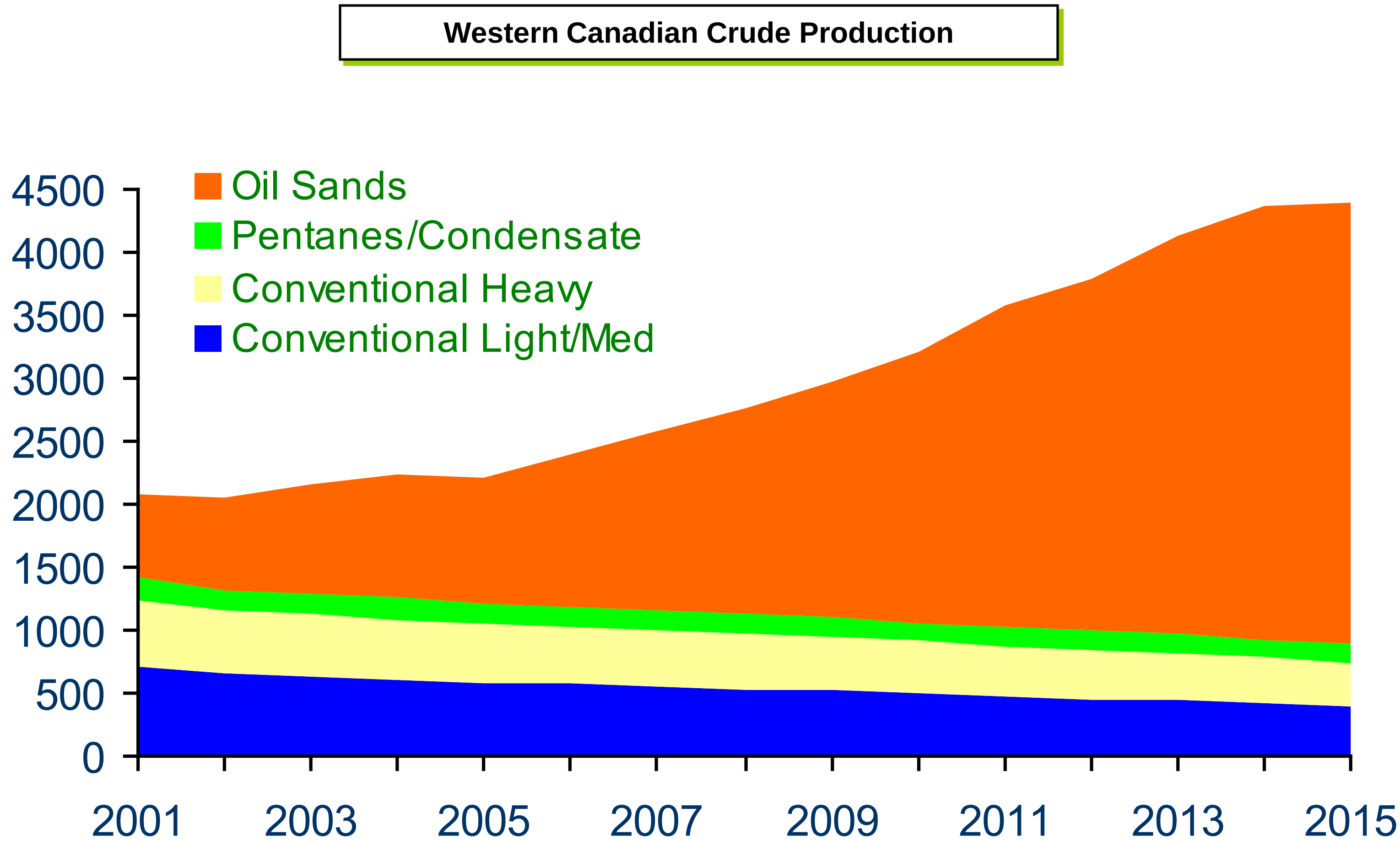
Terasen

KINDER MORGAN
CANADA INC.

Pipelines

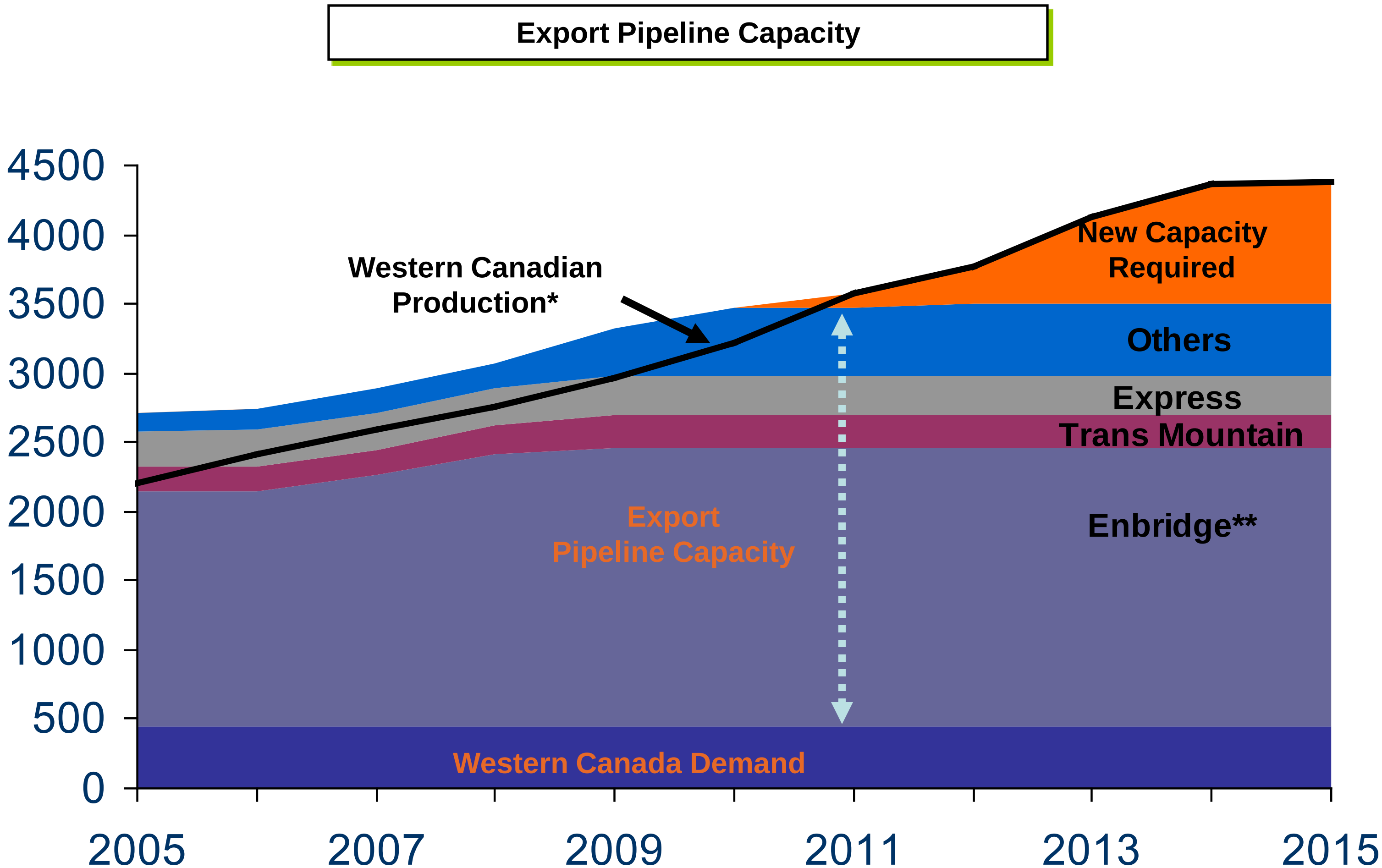
Petroleum Pipelines
Alberta Oil Sands Deposits

Canadian Crude Supply Forecast



CAAP May 2006 Canadian Crude Production and Supply Forecast

Canadian Crude Supply Forecast



CAAP May 2006 Canadian Crude Production and Supply Forecast

Trans Mountain - Regulatory

- Throughput growth has resulted in attractive returns from the 2001-2005 Incentive Toll Settlement
- ITS renewal nearing completion
  – MOU with CAPP
  – Final agreement expected July 2006
  – Settlement covers 2006 – 2010. Key elements:
    - Cost of service structure
    - Incentives on throughputs
    - 10.75% ROE on 45% equity
- TMX PSE and Anchor Loop Projects included in rate base, capital cost risk sharing

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Trans Mountain Expansion

- Oil sands production driving throughput growth
- Expansion can provide producers with greater access to California & Far East markets
- Completed 27,000 bpd expansion of the mainline at a cost of $19 million in October 2004

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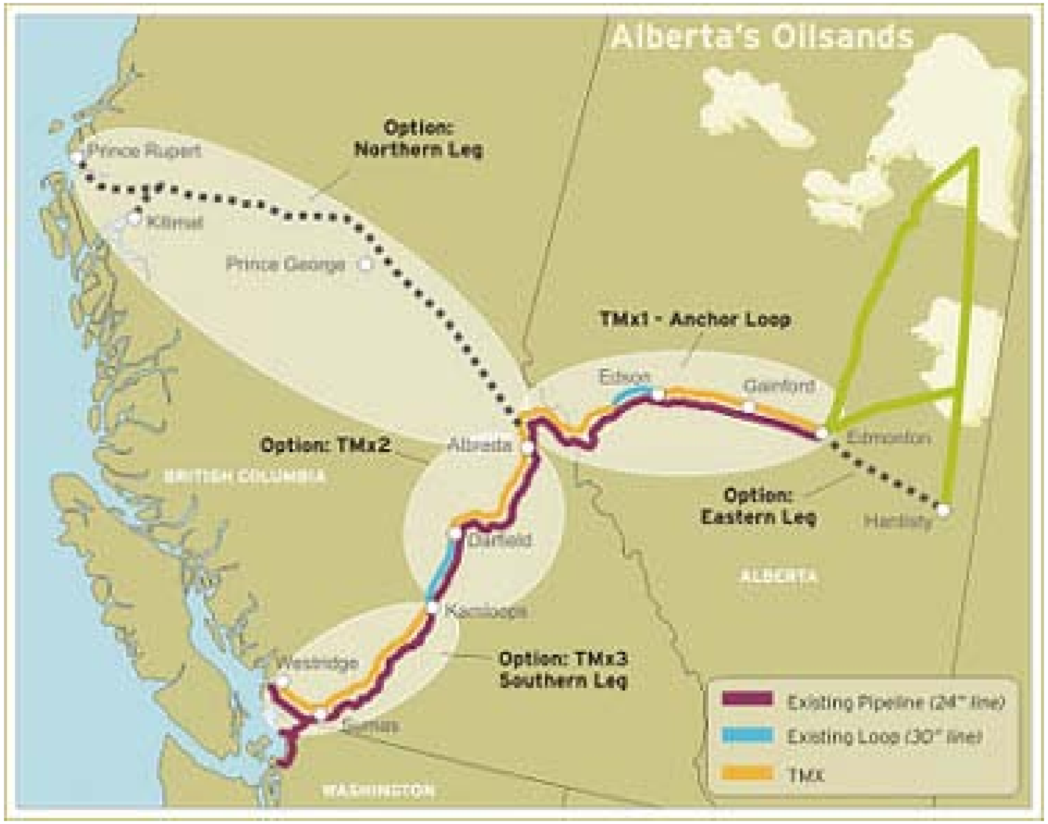
Trans Mountain Expansion



- Oilsands supply is actively seeking new markets
- Match with continued import growth on U.S. West Coast and Asia
- Expressions of Interest from potential shippers confirm demand for new capacity

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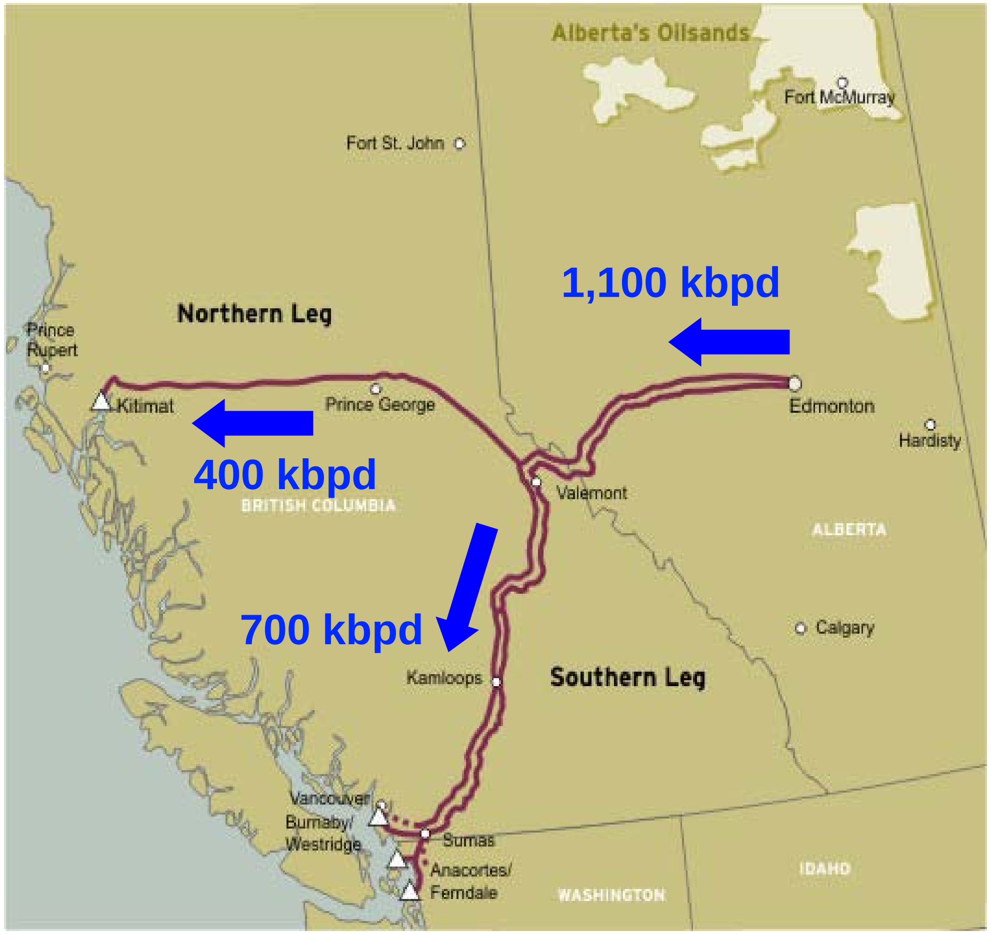
Trans Mountain Expansion

Staged Expansion To Capture Oilsands Growth



Existing: 225,000 bpd (heavy)

TMX-1: 2007/08

- **Pump Station Expansion -** 35,000 bpd
- **Anchor Loop -** 40,000 bpd

Southern Expansion: 2010/11

- **TMX-2 –** 100,000 bpd
- **TMX-3 –** 300,000 bpd

Northern Expansion: 2012

- **TMX-North –** 400,000 bpd

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TMx1 Expansion – Two Components

TMx1 Expansion – Two Components

- Pump Station Expansion Project
  - $228 million to add 35,000 bpd of pumping capacity
  - NEB Approval November 2005
  - Completion Q2 2007
- Anchor Loop Project
  - $438 million to add 40,000 bpd additional capacity through looping
  - NEB filing February 2006, approval expected Q4 2006
  - Completion by Q3 2008

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TMx2 and TMx3 Expansion

- TMx2 additional 100,000 bpd
- Forecast cost $1.3 billion, in-service 2010
- TMx3 additional 300,000 bpd
- Forecast cost $1.1 billion, in-service 2011
- Open Season to be concluded August 2006
- Move from negotiated tolls to contracted carrier, cost recovery and incentive sharing

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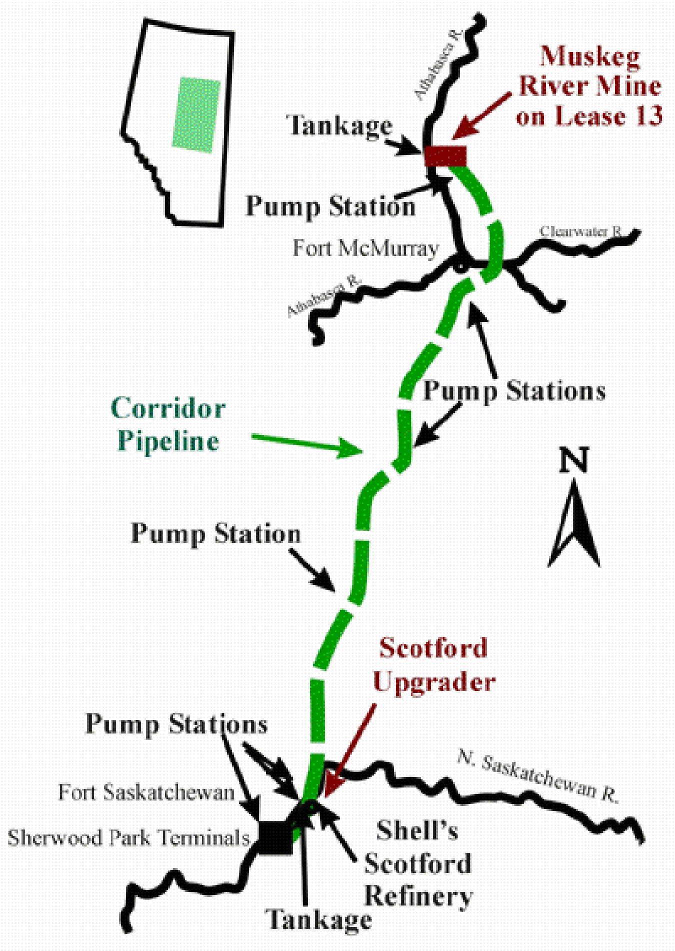
Corridor

- Completed on time and on budget in May 2003
- Backed by 25 year ship-or-pay contract with Shell Canada (60%), Chevron (20%) and Western Oil Sands (20%)
- Provides for recovery of all operating costs, depreciation, taxes and financing costs in revenue requirement
- 26% equity component, ROE is long-term Canada's plus 350 bps



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Corridor Expansion

- Linked to expansion plans for Athabasca Oil Sands Project
- Estimated cost up to $1.5 billion, depending on configuration
- Currently examining configuration options with Corridor shippers
- Engineering and procurement underway, final decision expected Q3 2006
- In-service expected in 2009
- Subject to terms of FSA

Terasen

Express

- Acquired January 2003
- 84% of the 280,000 post-expansion capacity is committed through long-term contracts
- Express expansion
  - Feeds PADD IV demand
  - In-service April 2005
    - On-time and under budget

Contracted Capacity

Summary by Shipper

Shipper	Credit Rating	2007	2012	2014	2015
Alberta Government	AAA		15,000		
Canadian Natural	BBB+	3,000	3,000		
ConocoPhillips	A-		10,000	30,000	25,000
EnCana Crude Mktg.	BBB+		70,000		
[ ]	AAA				14,000
[ ]	BB		13,800		10,000
Sinclair Oil*	AAA				10,000
Suncor Energy	A				30,000
Talisman Energy	BBB+	1,000			
Total		4,000	111,800	30,000	89,000

*Internal rating

Presentation to
Dominion Bond Rating Service

May 2004

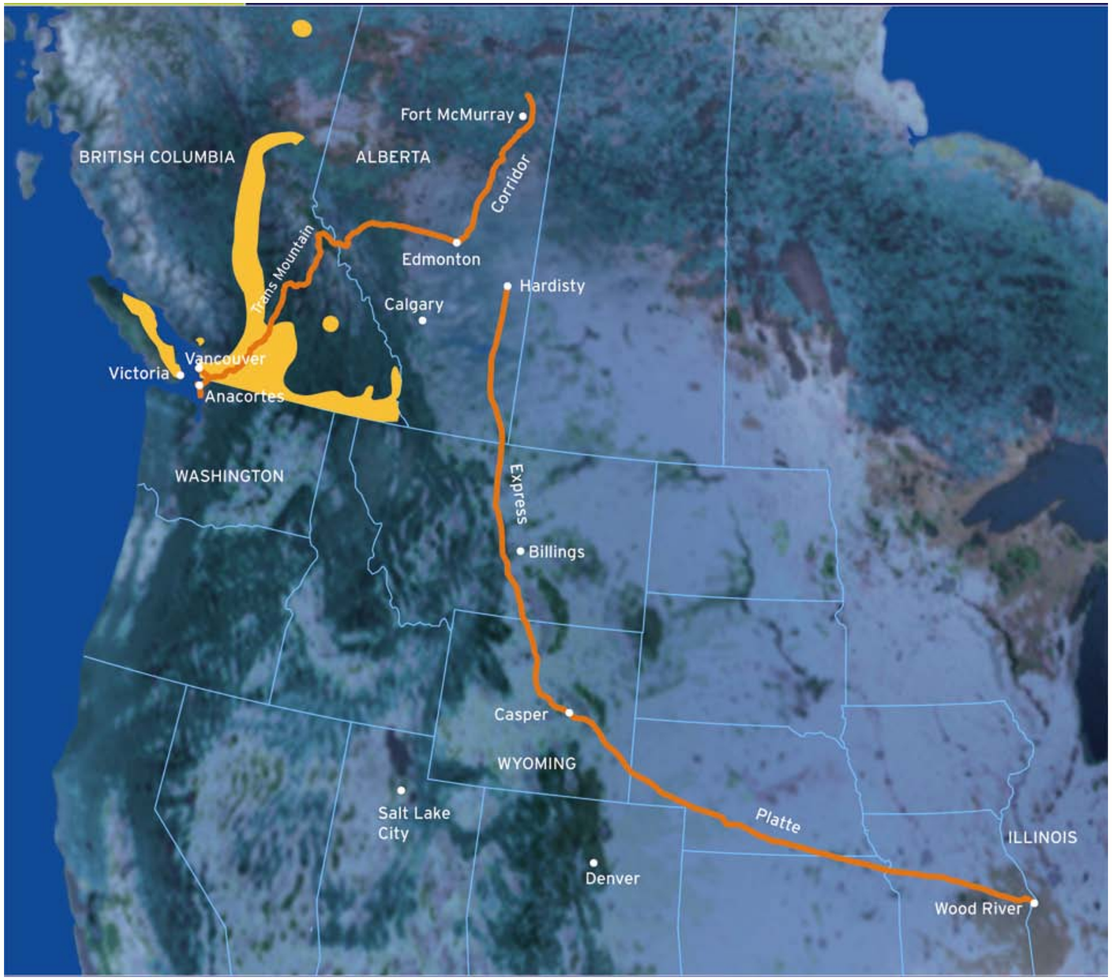
Presentation Overview

- Corporate overview
- Strategy
- Terasen Pipelines
- Terasen Gas
- Terasen Water and Utility Services
- Appendix – Municipal Leasing Transactions

Corporate Structure

- Terasen Inc.
  - Natural Gas Distribution
    - Terasen Gas
    - Terasen Gas (Vancouver Island)
  - Petroleum Transportation
    - Trans Mountain Pipeline
    - Corridor Pipeline
    - Express/Platte Pipelines (33.3% ownership)
  - Water & Utility Services
    - Terasen Utility Services
    - Terasen Waterworks
    - Customerworks (30% ownership)

Corporate Overview



Natural Gas Distribution

Petroleum Transportation

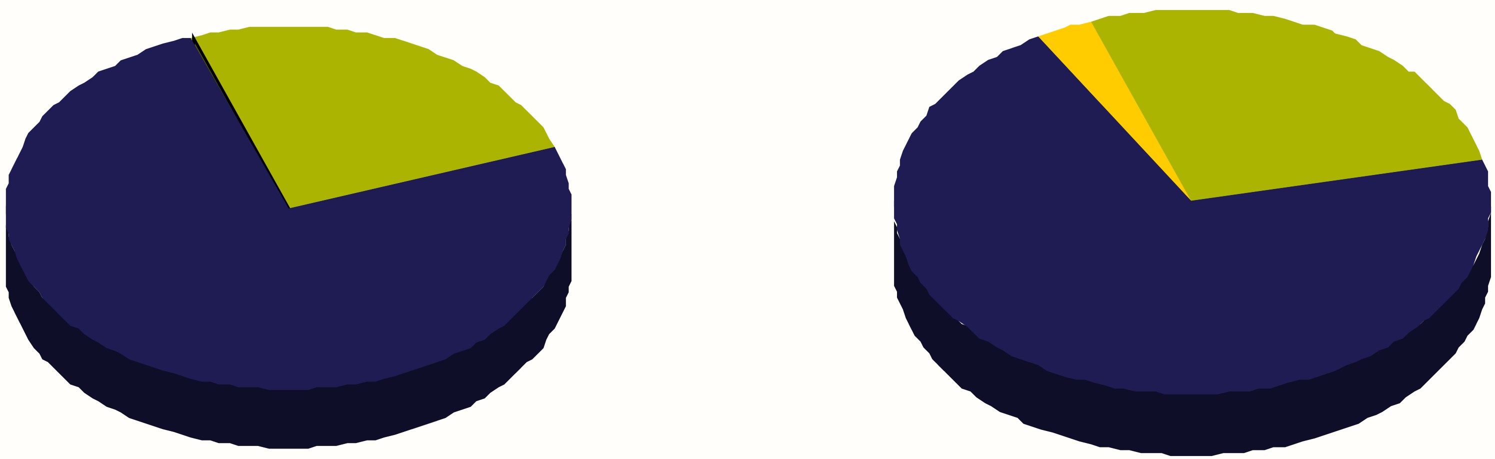
Corporate Overview

Operating Income: $366 million

(12 months ended December 31, 2003)

Assets: $4,915 million

(at December 31, 2003)



Natural Gas Distribution

Petroleum Transportation

Other Activities

2003 Highlights

- BCUC approval of a negotiated settlement of a 2004-2007 Performance-Based Rate Plan for Terasen Gas
- BCUC approval of a 2003-2005 regulatory settlement for TGVI, which extends incentive mechanisms
- Initiation of commercial operations of Corridor in May 2003, following on time, on budget completion of its construction
- Completion of the acquisition of a one-third interest in the Express Pipeline System and shipper support for the expansion plans for Express
- Initiation of the expansion of the Trans Mountain pipeline which will add 27,000 bbl/day in capacity

Management

- John Reid, President & CEO
  - Gordon Barefoot, Senior VP Finance & CFO
  - Stephen Swaffield, Senior VP Corporate Development
  - Patrick Lloyd, Senior VP HR & Governmental Affairs
  - Steve Richards, General Counsel, CRO & Corporate Secretary
  - Randy Jesperson, President, Terasen Gas
  - Richard Ballantyne, President, Terasen Pipelines
  - Brett Hodson, President, TUS & Terasen Waterworks

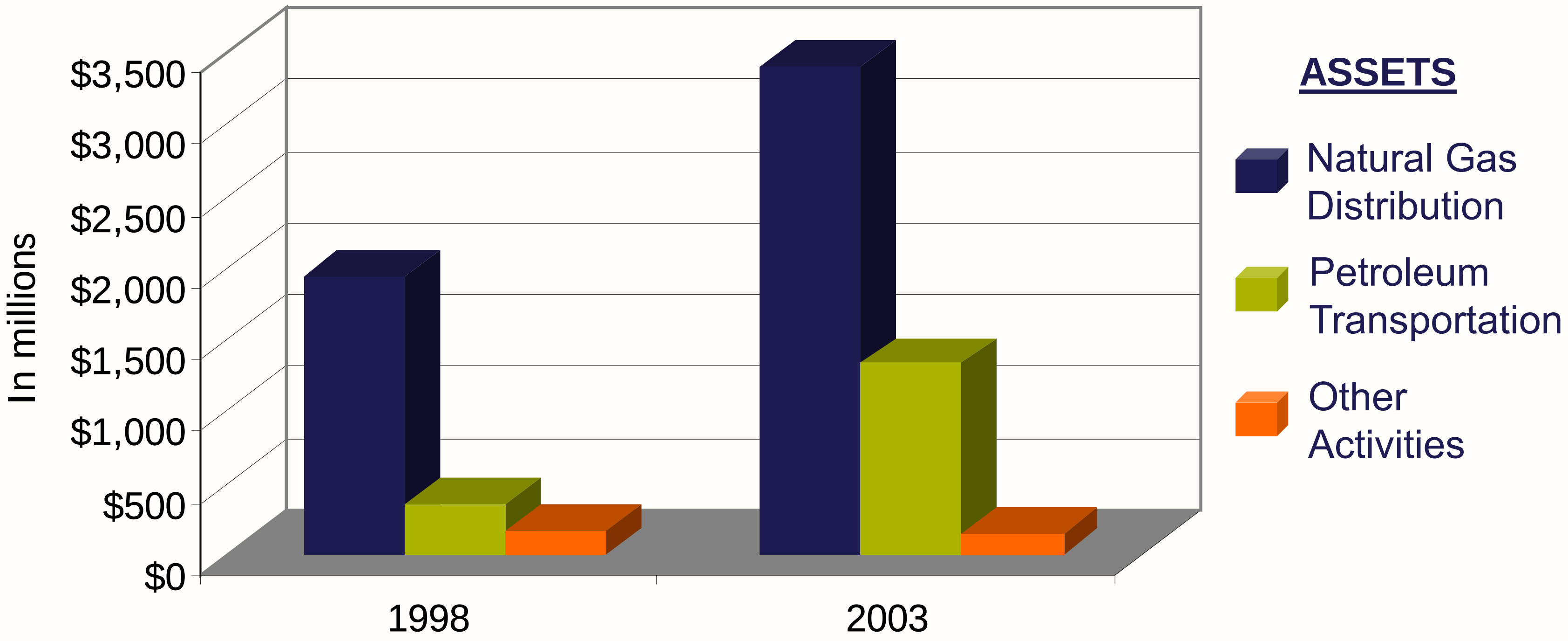
STRATEGY

Our Value Proposition

- **Focused** on our regulated businesses
- **Reliable** and consistent results from low risk businesses
- **Growing** and steadily outperforming through value creation

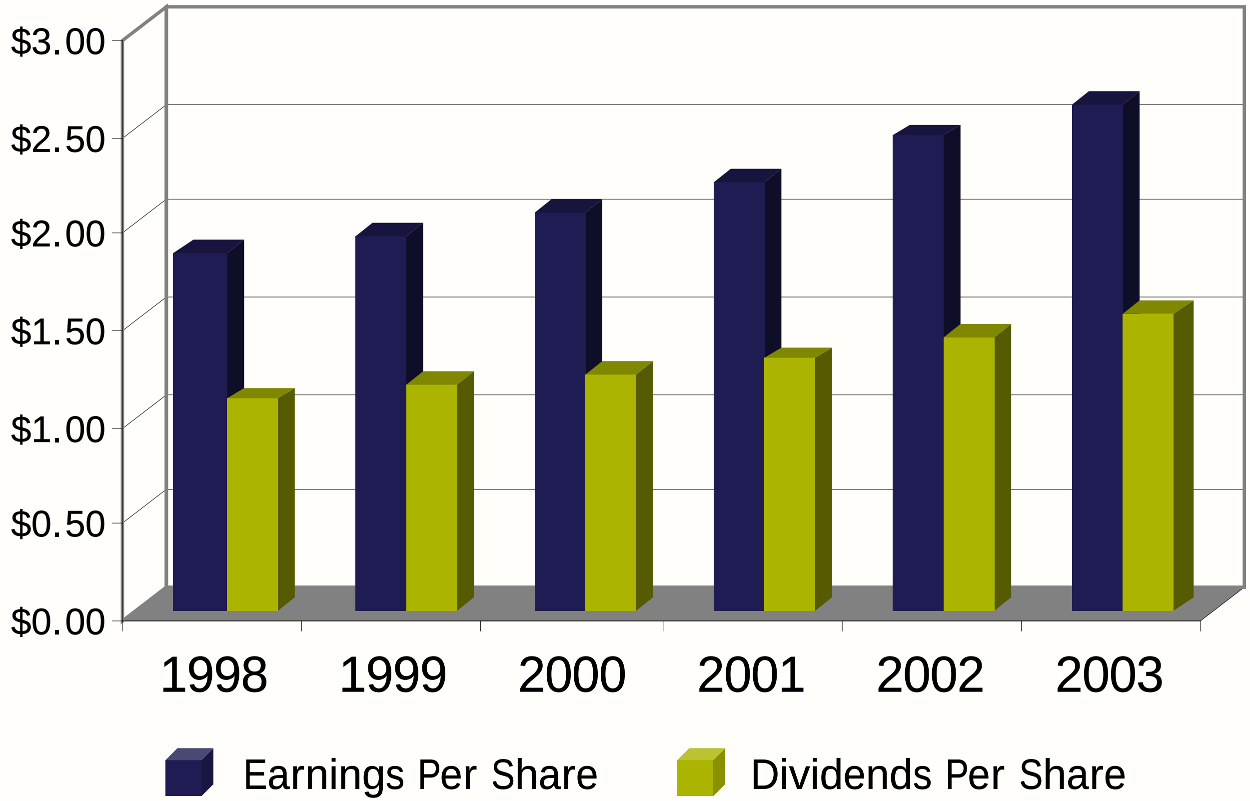
Focused

Growth has come from investments in core regulated businesses



Reliable

Consistent results from low risk businesses – target earnings growth of 6% and dividend payout of 60%

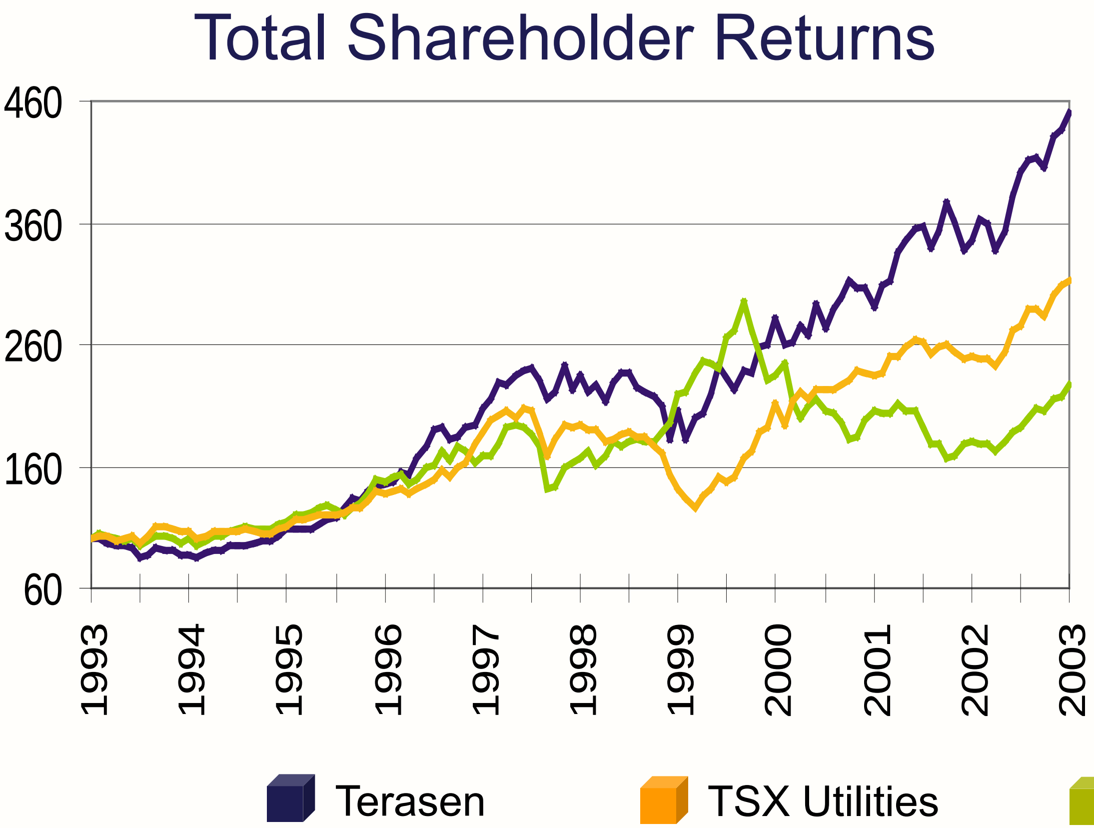


7.2% Annual EPS Growth

7.0% Annual DPS Growth

Growing

Consistent outperformance through value creation



Annualized Total Returns

	One Year	Three Year	Five Year	Ten Year
Terasen	30%	17%	14%	16%
TSX Utilities Index	27%	14%	10%	12%
TSX Composite Index	27%	-1%	7%	9%

For the period ended December 2003

Asset and Risk Management

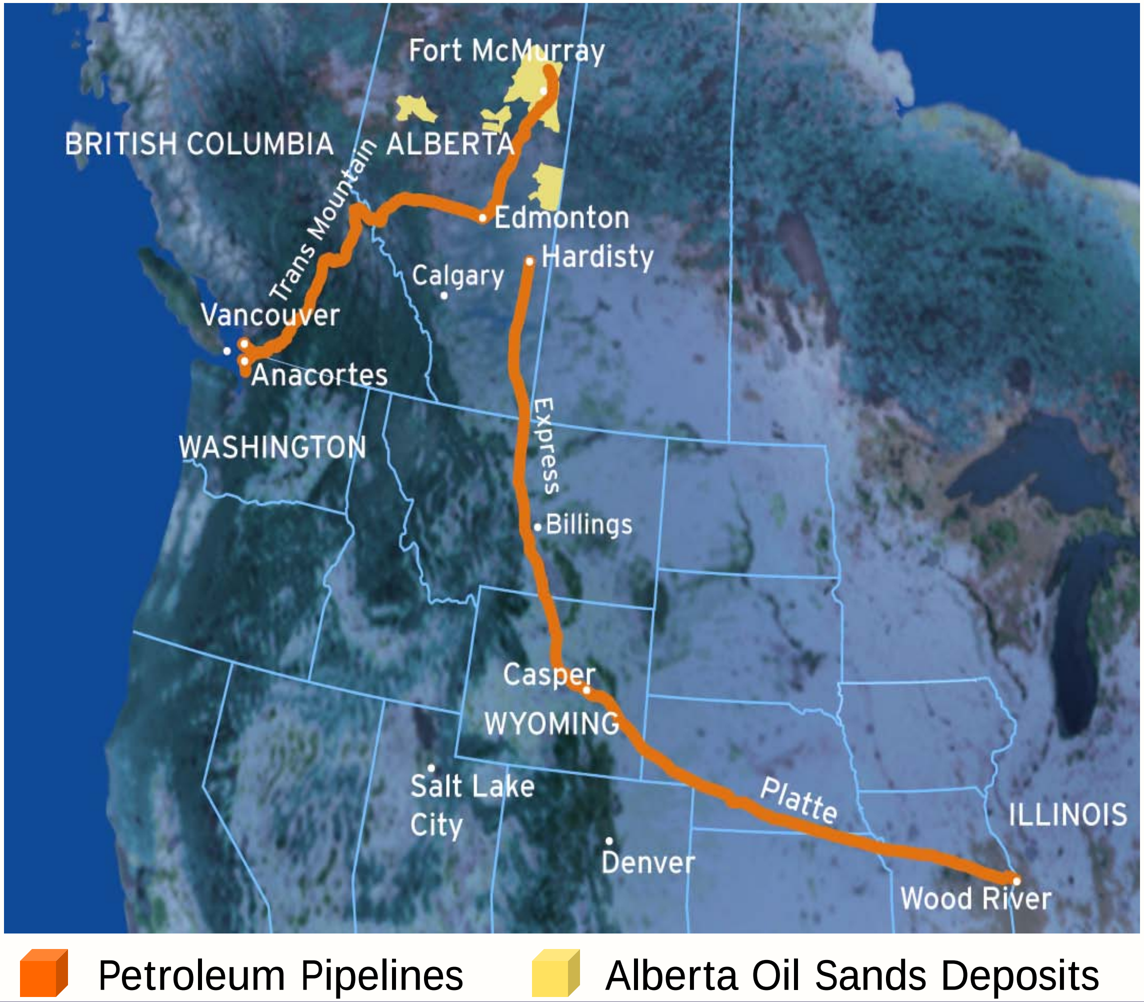
- 97% of assets are regulated
  - Major growth is in regulated activities
- Regulatory arrangements
  - No weather or customer usage risk
  - No cost of gas risk
- No international investments
- No non-regulated energy trading

Core Value Strategies

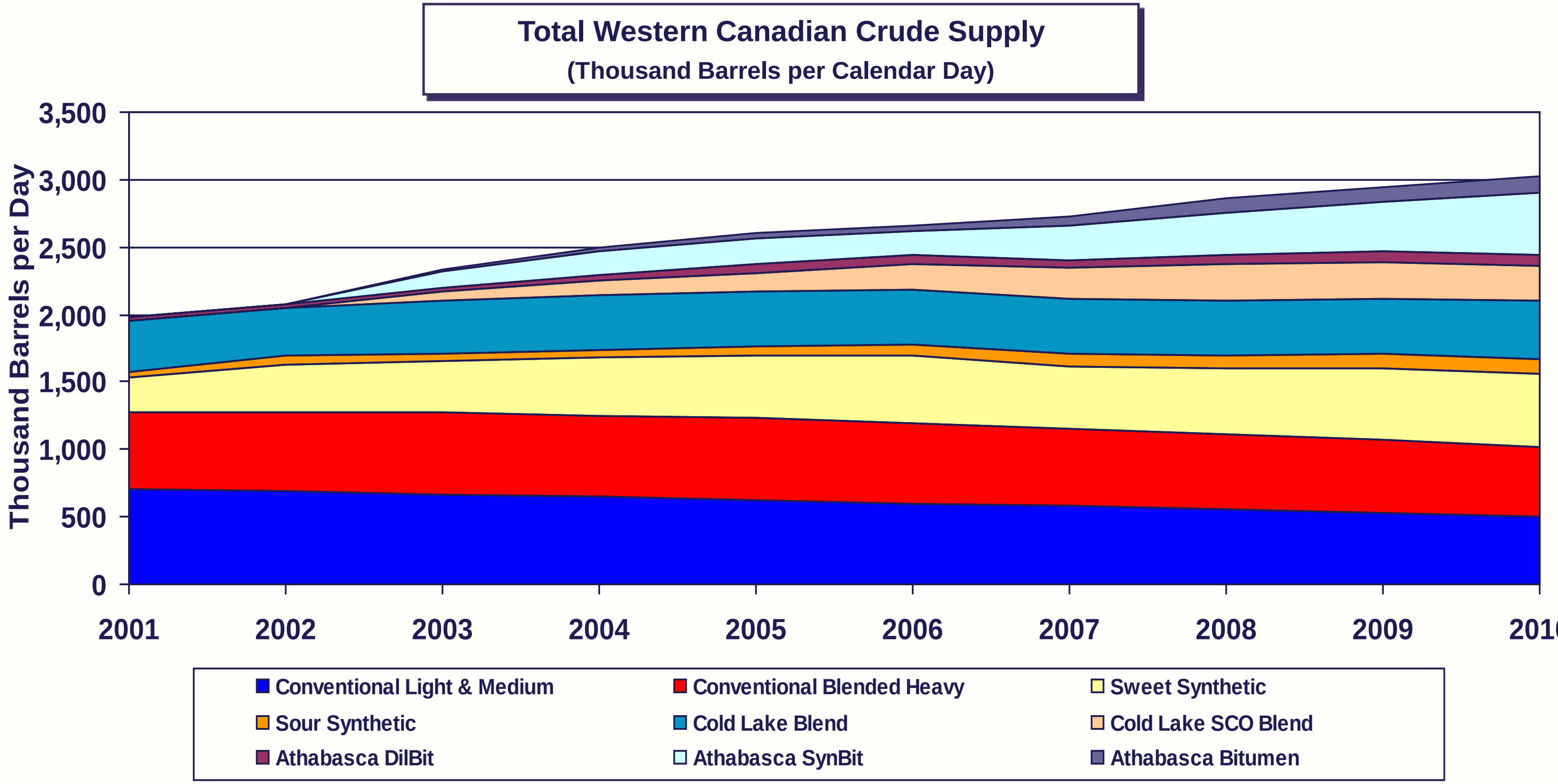
- **Operational excellence** within incentive regulation
- **Focused growth** based on value creation
- **Financial excellence** ensuring access to competitive sources of capital

Terasen Pipelines

Terasen Pipelines



Canadian Crude Supply Forecast

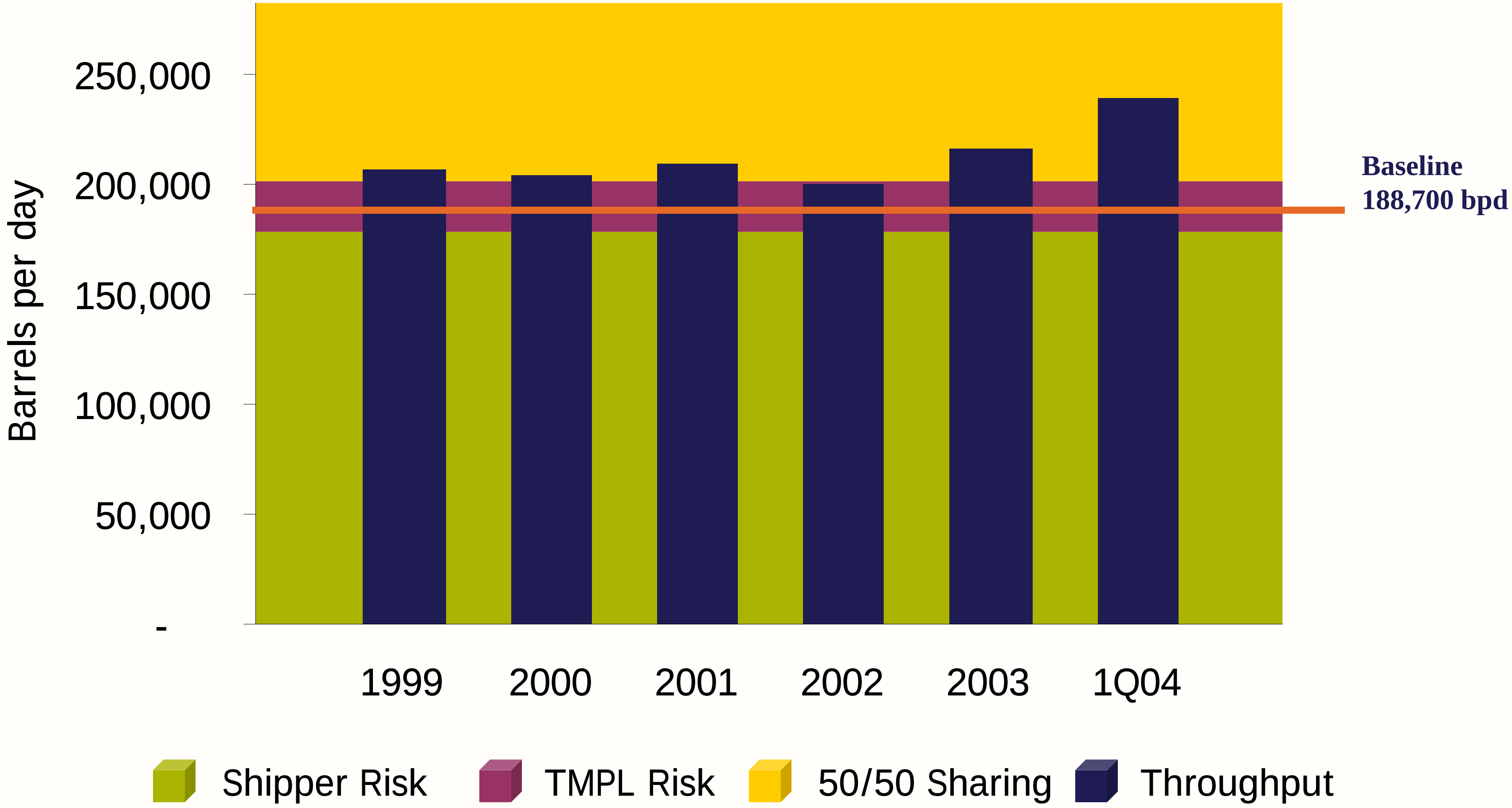


CAPP Upper Supply Case – Total Supply

Trans Mountain 2001 – 2005 Incentive Toll Settlement

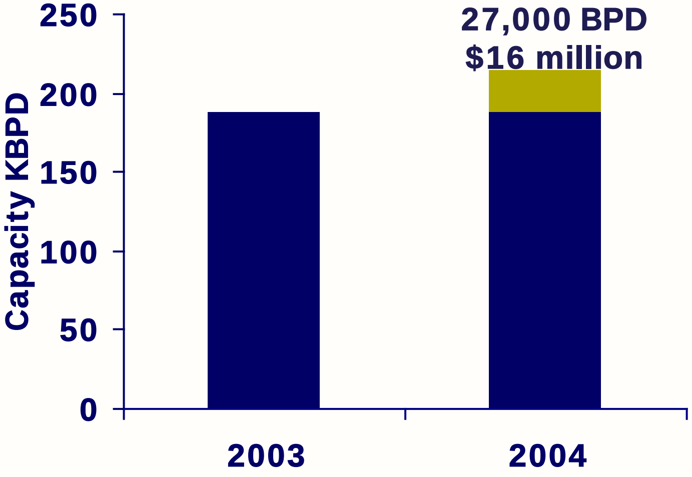
- Structured around Shipper's desire for fixed tolls
- TMPL benefits from 100% of operating cost reductions
  - No escalation of tolls for inflation
- TMPL assumes limited throughput risk
- Incentives for additional throughpu

Trans Mountain
Canadian Throughput and Volume Risk



Trans Mountain

- Oil sands production driving throughput growth
- Expansion can provide producers with greater access to California & Far East markets

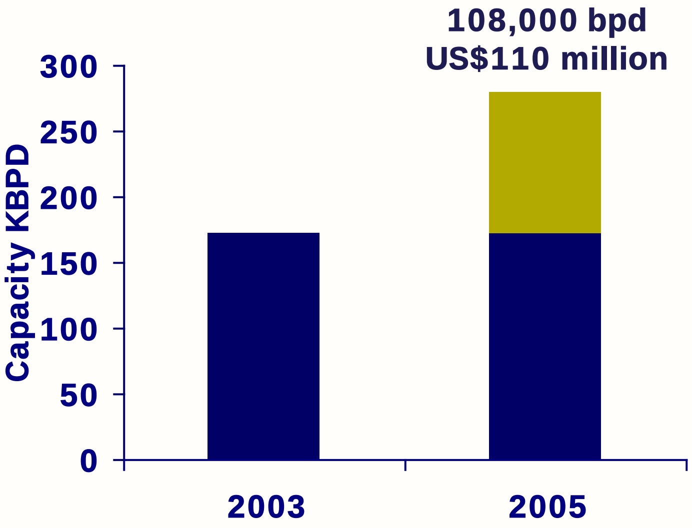


Express

- Acquired January 2003
- Express has been running at capacity, with 85% of total capacity of 172,000 bpd committed through long-term contracts
- Strong shipper response to recent open season
- Following the expansion 79% of the 280,000 total capacity will be committed through long-term contracts

Express

- Both phases of the expansion are expected to be completed by April 2005

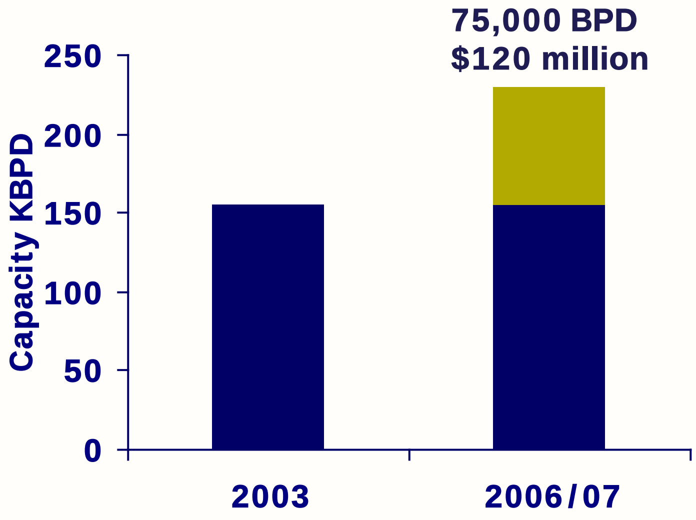


Corridor

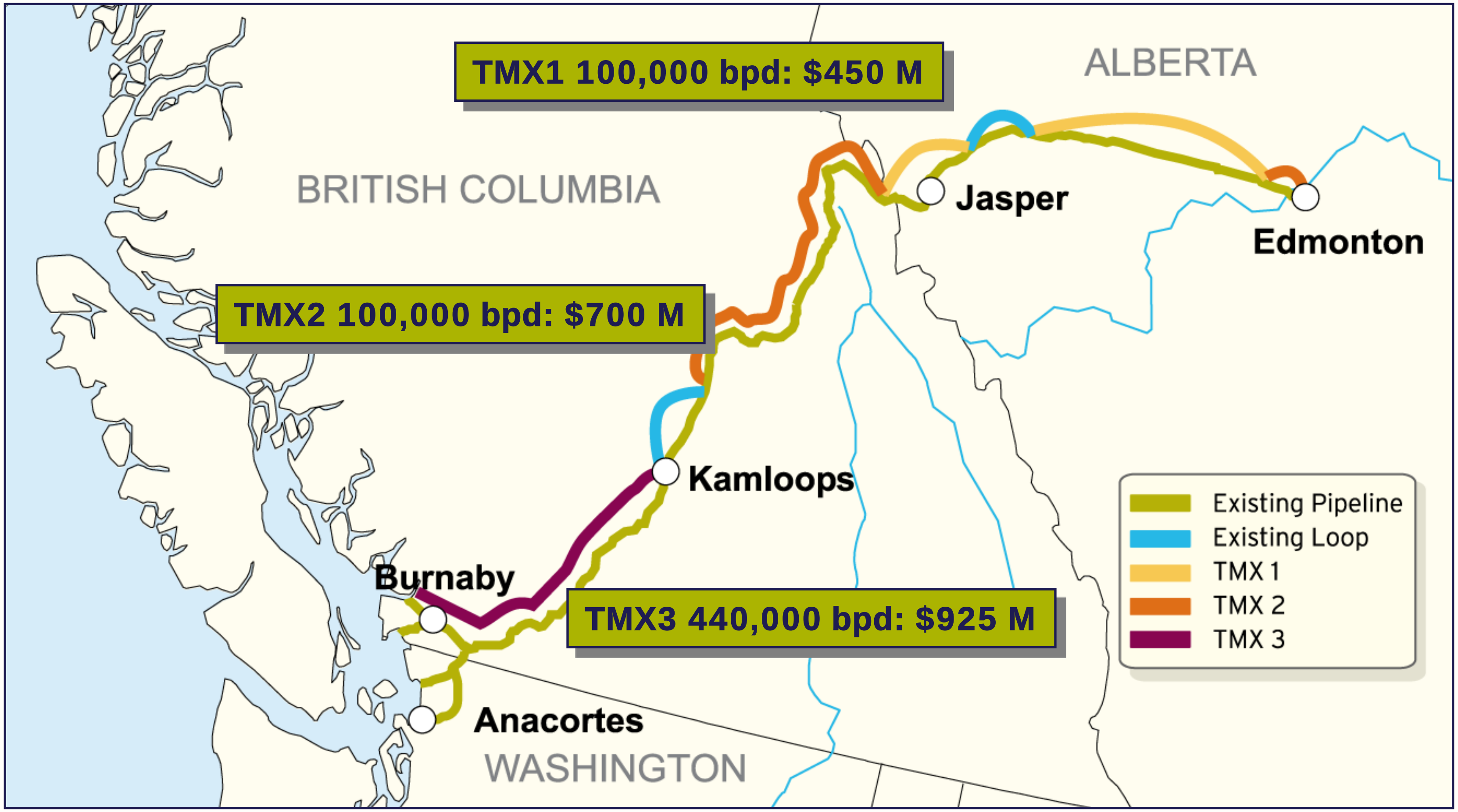
- Completed on time and on budget in May 2003
- Backed by 25 year ship-or-pay contract with Shell Canada (60%), Chevron (20%) and Western Oil Sands (20%)
- Provides for recovery of all operating costs, depreciation, taxes and financing costs in revenue requirement
- 25% equity component, ROE is long-term Canada's plus 350 bps

Corridor

- Expansion will be undertaken on similar terms as original agreement
- Timing dependent on mine expansion plans



TMX


TMX1 100,000 bpd: $450 M
TMX2 100,000 bpd: $700 M
TMX3 440,000 bpd: $925 M
ALBERTA
BRITISH COLUMBIA
WASHINGTON
Jasper
Edmonton
Kamloops
Burnaby
Anacortes
Existing Pipeline
Existing Loop
TMX 1
TMX 2
TMX 3

TMX Advantages

- Built in stages
  - Lower construction risk
  - Matches capacity with supply/demand growth
  - Lowers risk of overbuild
- Washington State refinery access
  - 550,000 bpd capacity
  - 10% current market share
- Existing rights-of-way
  - Options on private land

Terasen

Terasen Gas

2004-2007 PBR Settlement

- Capital structure – 33% common equity/67% debt

- Allowed ROE is determined annually using BCUC-established formula
  - ROE = Forecast Cda. Bond Yield + Risk Premium
  - Mechanism is similar to NEB Multi-Pipeline formula
  - ROE for Terasen Gas in 2004 was set at 9.15%, compared with 9.42% in 2003

2004-2007 PBR Settlement

- Performance-based regulatory settlement with incentives for operating efficiencies – benefits shared 50% with customers

- Performance-based regulatory arrangements have enabled Terasen Gas to exceed allowed ROE in every year since 1994

2004-2007 PBR Settlement

- O&M formula:
  - [Base Cost x (1+Growth) x (1+Inflation-Adjustment factor)]
  - Adjustment factors of 50% CPI in 2004 and 2005, and 66% CPI in 2006 and 2007

- New deferral accounts established for insurance and pension costs

2004-2007 PBR Settlement

- Gross margin protected by two deferral accounts:
  - Gas Cost Reconciliation Account (GCRA)
  - Revenue Stabilization Adjustment Mechanism (RSAM)

- RSAM defers any variances in use per customer among residential and commercial customers
  - Eliminates exposure to weather variations
  - Also eliminates exposure to reductions in use per customer caused by other factors (e.g. higher prices)

2004-2007 PBR Settlement

- RSAM does not cover margin from industrial customers
  - Less sensitive to weather fluctuations
  - Industrial margin is reset annually
  - Regulatory relief can be sought if industrial margins fall significantly below forecast
- Industrial and large commercial customers can select commodity+transportation or transportation service only
  - Terasen earns approximately the same margin in either case

2004-2007 PBR Settlement

- Variances between actual and forecast gas costs are deferred and recovered through GRCA
- During 2003, RSAM and GCRA balances were recovered in rates, thereby reducing the recovery balances
  - Combined GCRA/RSAM balance $34.8 million at end of 2003, compared with $76.7 million at the end of 2002

2004-2007 PBR Settlement

- BCUC has approved a mechanism for quarterly adjustment of rates
  - If projected recovery of:
    a) actual gas costs, and
    b) amortization of prior GCRA balances,
    falls outside of 95-105% deadband, rates are adjusted, subject to BCUC approval
- Lower natural gas costs resulted in the BCUC approving a decrease in customer rates in December 2003 (7.5% decrease for the average residential customer)

2004-2007 PBR Settlement

- Gas Supply Incentive Program
  - Provides an incentive to mitigate fixed costs of gas supply & transportation by selling excess gas and transportation capacity to off-system customers
  - Has generated shareholder revenues of $1-2 million per year over the last several years
- Unbundling
  - Terasen Gas, BCUC & customer representatives have all been supportive of unbundling
  - Unbundling for commercial customers expected in late 2004
  - No financial impact on Terasen anticipated

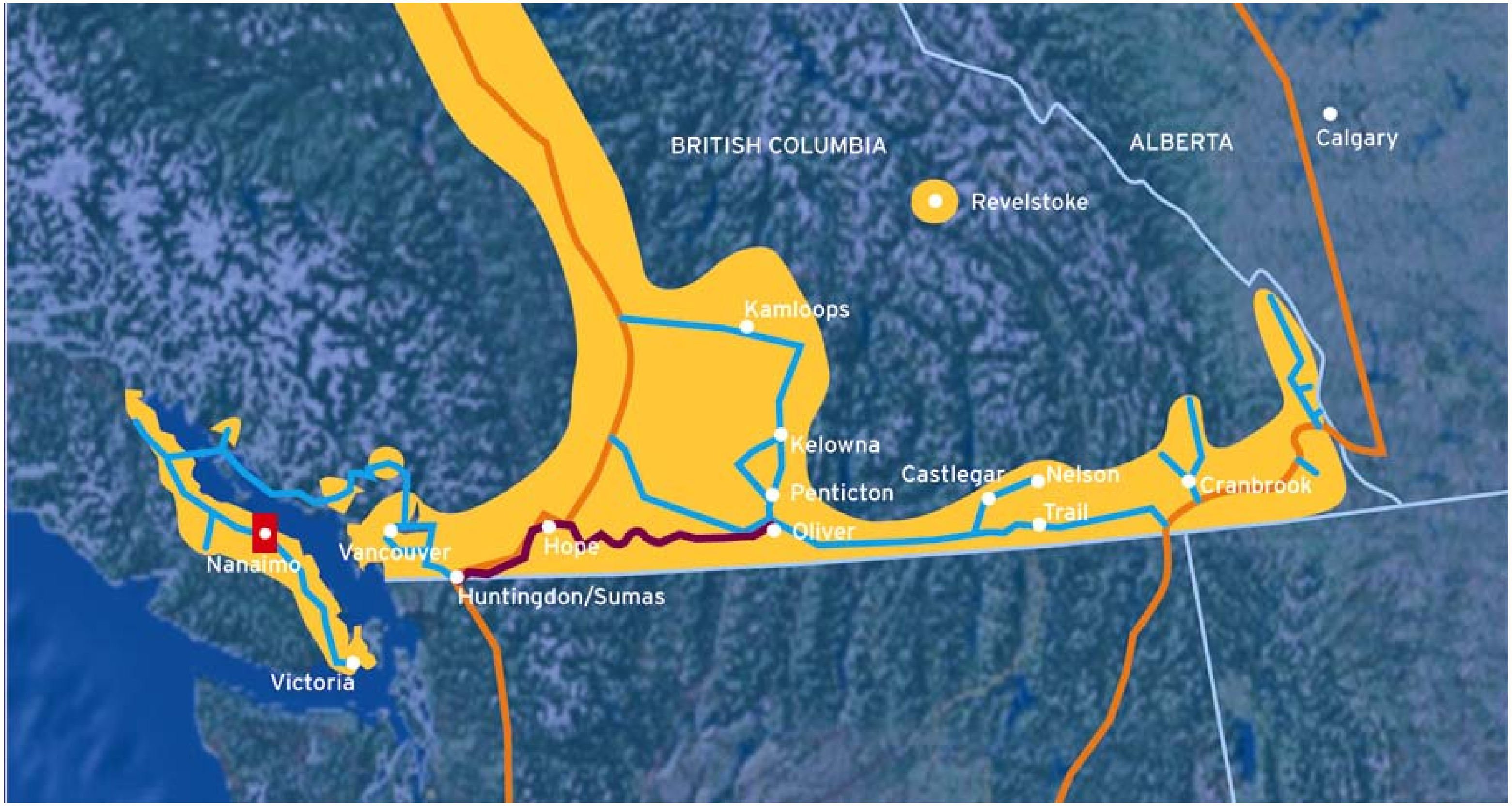
TGVI – 2003-2005 Regulatory Settlement

- Took effect January 1, 2003
- Capital structure – 35% common equity/65% debt
- Allowed rate of ROE that is 0.50% higher than Terasen Gas – 9.65% for 2004, compared with 9.92% in 2003
- Continuation of operating and maintenance cost incentive mechanisms
- Deferral accounts protect against cost of gas, weather risk, etc. – similar to Terasen Gas, but more comprehensive

TGVI – RDDA

- Revenue deficiency deferral account (RDDA) arose from low customer rates charged prior to December 31, 2002
  - Deferral account balances funded by preferred shares issued to parent
  - BCUC directed to set rates to recover RDDA over the shortest period possible, while remaining competitive with alternative energy sources
  - Customer rates set using conventional methods beginning January 1, 2003

New Infrastructure Projects



Terasen Transmission Lines

Terasen Distribution Service Area

Other Natural Gas Lines

Proposed Inland Pacific Connector Pipeline

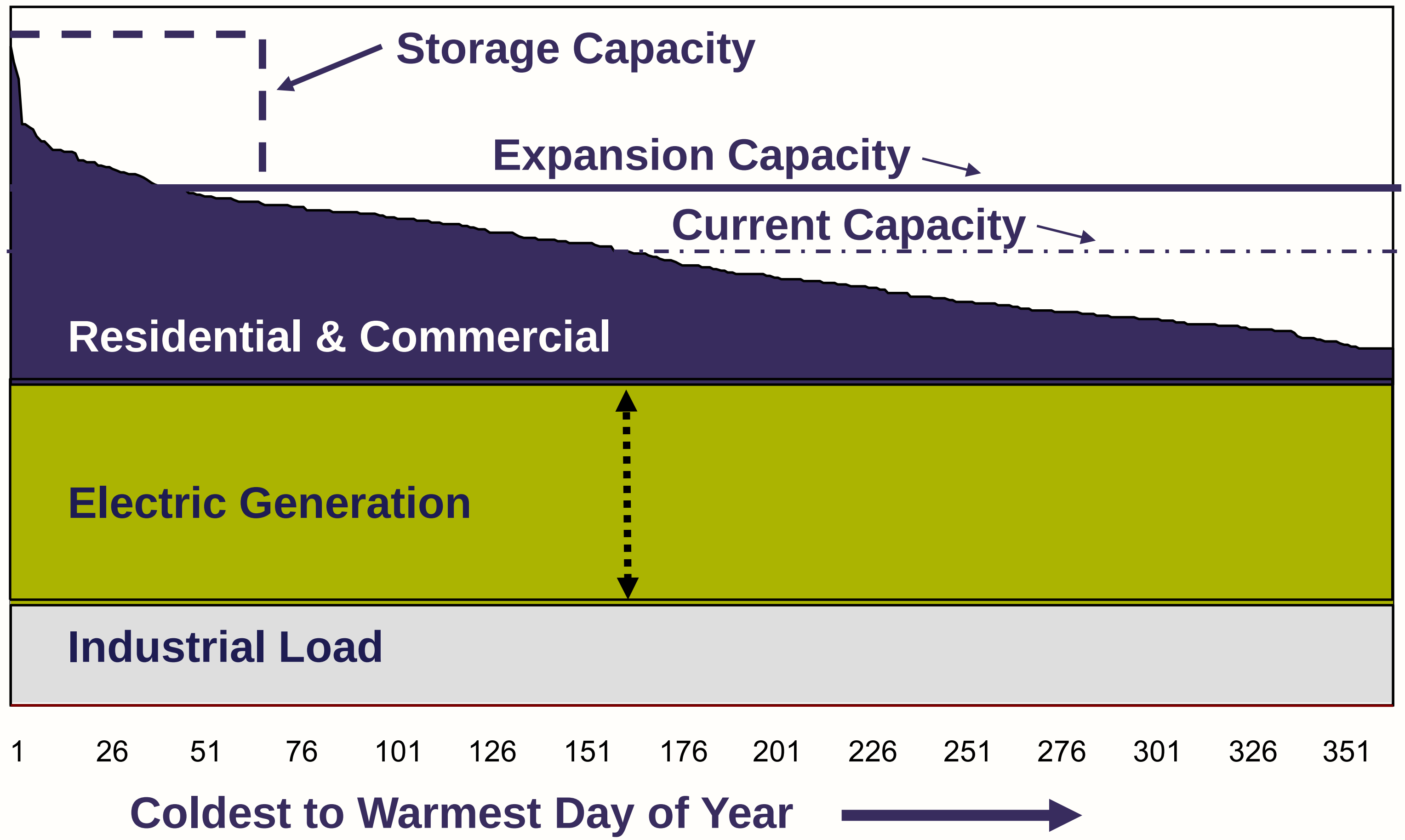
Proposed LNG Storage Tank

New Infrastructure Projects

Capacity expansion to Vancouver Island

- New on-Island power generation needed
- $180 million capacity expansion proposed
  - Additional compression and a new LNG tank

New Infrastructure Projects



New Infrastructure Projects

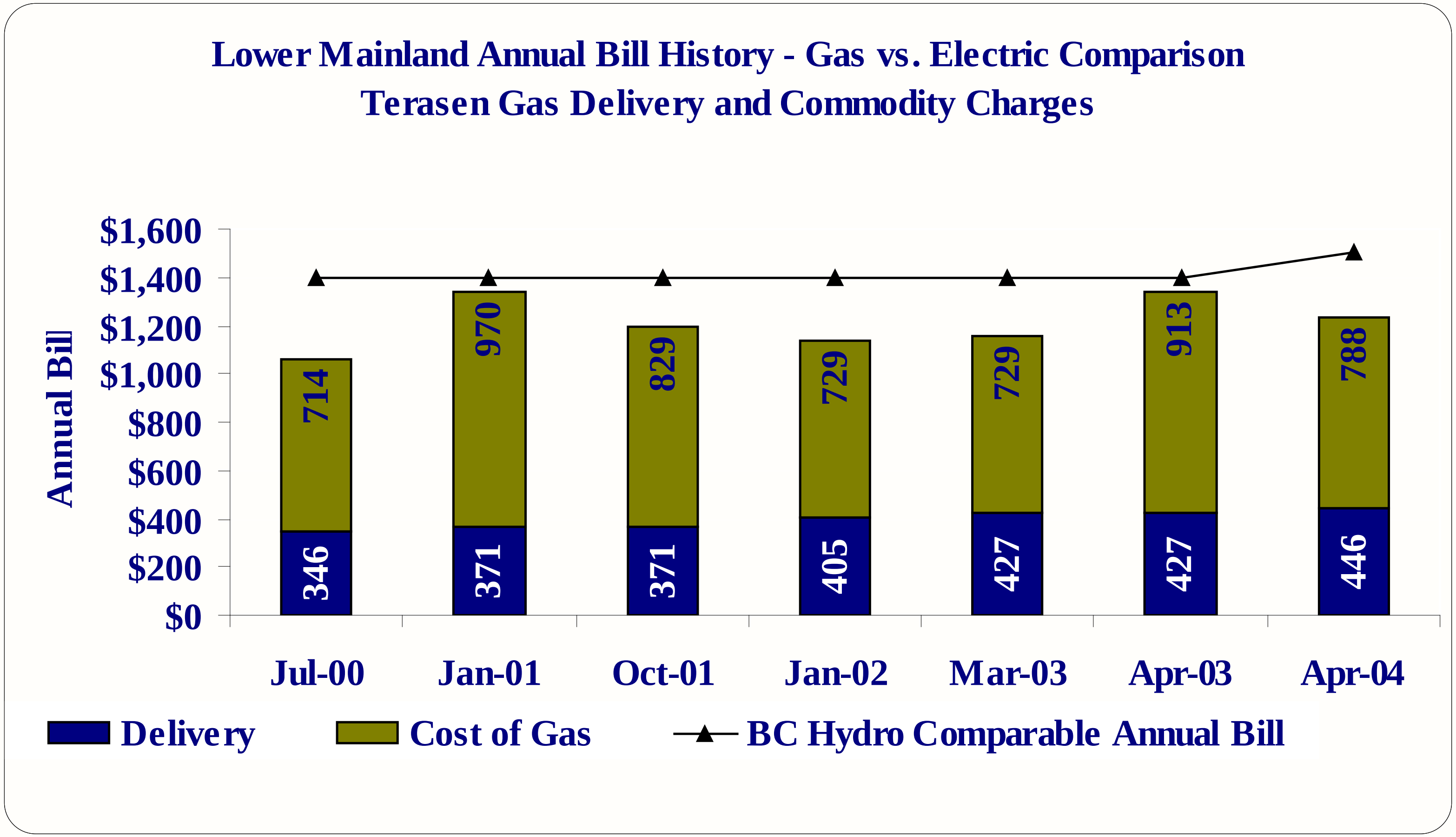
Inland Pacific Connector

- New pipeline to extend Southern Crossing pipeline to Sumas/Huntingdon
- Positioned to meet demand for natural gas capacity expansion in Pacific Northwest

Price Competitiveness

- In B.C., natural gas has historically enjoyed a significant cost advantage vs. alternative fuels, including electricity
- Increases in the market price of natural gas, combined with a government-mandated electricity price freeze, eroded this advantage
- Terasen Gas maintains an active price risk management program (on behalf of customers) which mitigates this risk
- Recent rate reductions have partially restored natural gas' price advantage

Price Competitiveness



Terasen Utility Services

Terasen Waterworks

Water and Utility Services

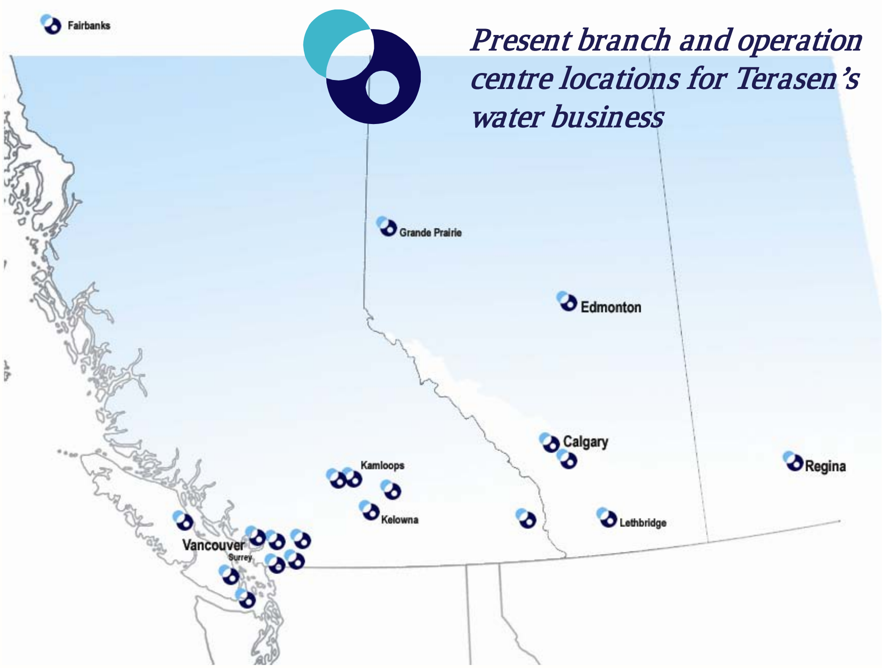
- Continues to be a relatively small part, but growing, of our asset base and operating income

- Looking for opportunities to capitalize on economies of scope and scale, in terms of the services that are provided and regions that are covered

Water and Utility Services

- Largest private water services company in Western Canada

- Focus on annuity operating contracts and selective investment opportunities



Fairbanks Acquisition

- April 2004 – acquired a 50% interest in Fairbanks Sewer & Water (FSW) for approximately US$30 million
- FSW provides water and wastewater treatment and water distribution services to the 82,000 residents of Fairbanks, Alaska
- FSW will provide a model for other opportunities in Western North America
- Option to purchase remaining 50% in 2009 at fair market value
- The transaction is subject to regulatory approvals, and is expected to be finalized in the summer of 2004

Appendix: Municipal Leasing Transactions

Municipal Leasing Transactions

- Certain municipalities have franchise agreements which permit the municipality to purchase the distribution assets at “fair value”
  - No munis in Vancouver area have this option
  - Most munis elsewhere have given up the option through agreement renewals
- Munis can finance Terasen Gas assets with 100% MFA debt, and does not pay tax.
- Leasing arrangements negotiated to provide Munis with financial benefits and risks of ownership, while allowing Terasen Gas to operate.

Municipal Leasing Transactions

- Terasen Gas assets are leased to Kelowna for $50 million prepaid rent under a long-term capital lease
- Terasen Gas enters into an operating lease to operate the assets
  - Kelowna is paid the revenue requirement associated with $50 million of utility capital
    - return on equity
    - cost of debt
    - income taxes
    - depreciation
- Changes in revenue requirement (e.g. ROE) are flowed through to Kelowna

Municipal Leasing Transactions

- No change for regulatory purposes
  - Lease simply flows through certain components of revenue requirement to Munis
  - No impact on customers
- Terasen Gas retains option to terminate agreements at the end of 17 years and retain ownership benefits
  - Termination payment = depreciated book value

Municipal Leasing Transactions

- Terasen Gas transfers risk and reward associated with assets and retains the option to control the assets after year 17
- Closed Nelson lease agreement on March 2, 2004 – value $8 million
- Terasen Gas has entered into leasing transactions with a total value of $83 million
- Total potential value (including current leases) of $200 million

Presentation to Dominion Bond Rating Service

May 2005

Terasen

Presentation Overview

- Corporate Overview
- Terasen Gas
- Terasen Pipelines
- Terasen Water and Utility Services

Corporate Structure

- Terasen Inc.
  - Natural Gas Distribution
    - Terasen Gas
    - Terasen Gas (Vancouver Island)
    - Other
  - Petroleum Transportation
    - Trans Mountain Pipeline
    - Corridor Pipeline
    - Express/Platte Pipelines (33%)
    - Other
  - Water & Utility Services
    - Terasen Waterworks
    - Terasen Utility Services
    - Fairbanks Sewer & Water (50%)
    - Customerworks (30%)
  - Other Activities
    - Terasen International
    - Clean Energy (45%)
    - Corporate

Management

- **John Reid**, President & CEO
  - **Gordon Barefoot**, Senior VP, Finance & CFO
  - **Stephen Swaffield**, Senior VP, Corporate Development
  - **Patrick Lloyd**, Senior VP, HR & Governmental Affairs
  - **Steve Richards**, Senior VP, General Counsel & Corporate Secretary
  - **Randy Jespersen**, President, Terasen Gas
  - **Richard Ballantyne**, President, Terasen Pipelines
  - **Brett Hodson**, President, Terasen Water & Utility Services

Area of Operations

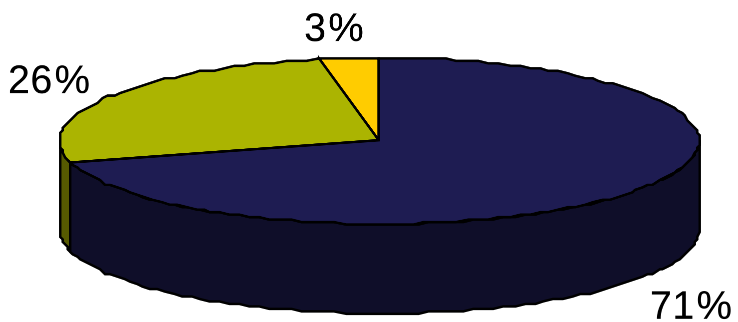
Petroleum Transportation

Natural Gas Distribution

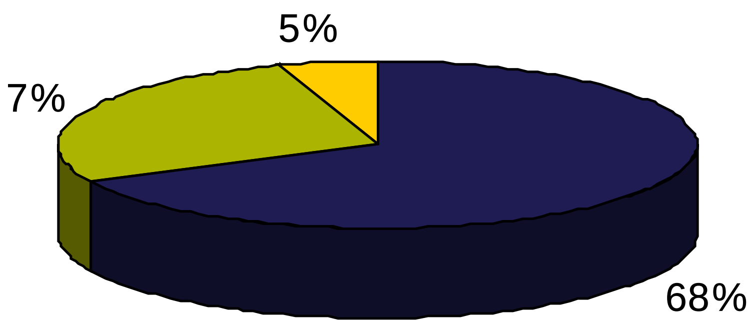
Terasen

Corporate Overview

Operating Income: $377 million
(12 months ended December 31, 2004)



Assets: $4,971 million
(at December 31, 2004)



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2004 Highlights

- Natural Gas Distribution – achieved operating efficiencies between TGVI and Terasen Gas, which were shared with customers
- Trans Mountain Expansion – completed the 27,000 barrel per day upgrade of the Trans Mountain pipeline
- Express Expansion – commenced construction on the expansion, which is now in-service and providing additional capacity of 108,000 bpd

2004 Highlights

- Fairbanks Acquisition – acquired a 50% interest in Fairbanks Sewer and Water Inc.

- Earnings Growth – Continuing earnings in 2004 were \$1.40 per share, up 6.9% over EPS (before non-recurring items) of \$1.31 in 2003

- Financial Strength – EBIT Interest Coverage increased from 2.1x in 2003 to 2.4x in 2004, and Common Equity/Total Capital increased from 30.0% to 31.7%

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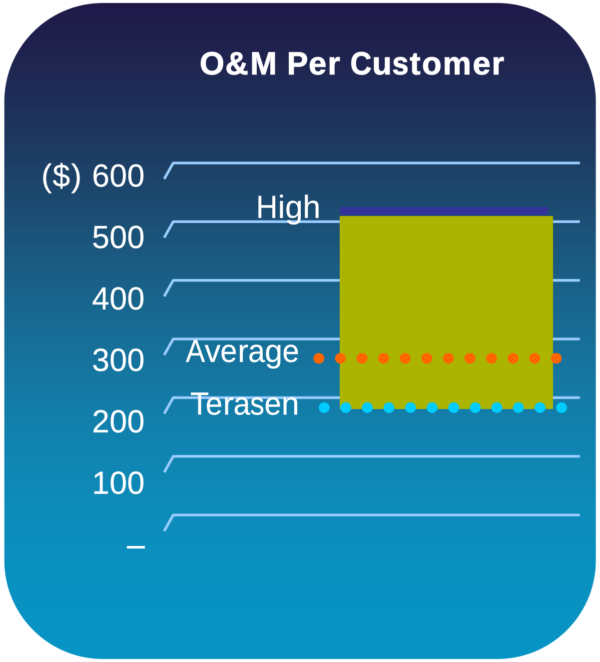
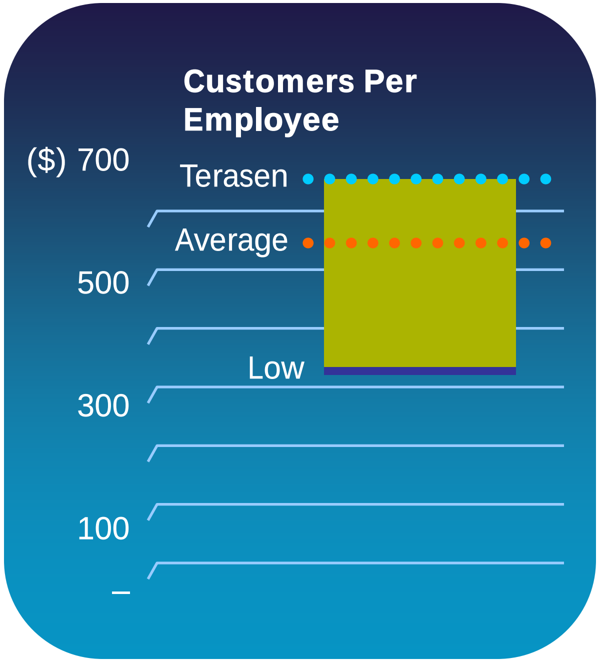
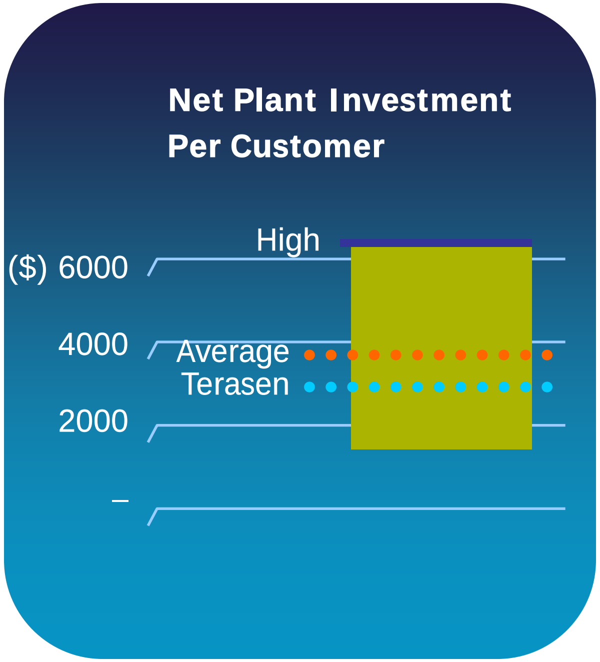
Terasen Gas/TGVI Integration

- Management and operational integration of TGI and TGVI is substantially complete
  - Single management team, common processes, common systems
- Earnings contribution from operational efficiencies was $4.1 million in 2004
  - Reinforces Terasen Gas' best-in-class position on operating efficiency

Operating Efficiency







Source: LSM Consulting

Price Competitiveness

- Increases in the market price of natural gas, combined with a government-mandated electricity price freeze, have eroded the historical advantage over electricity
- Terasen Gas maintains an active price risk management program (on behalf of customers) which mitigates this risk
- BC Hydro has been supportive of demand-side management initiatives to encourage efficient energy use decisions

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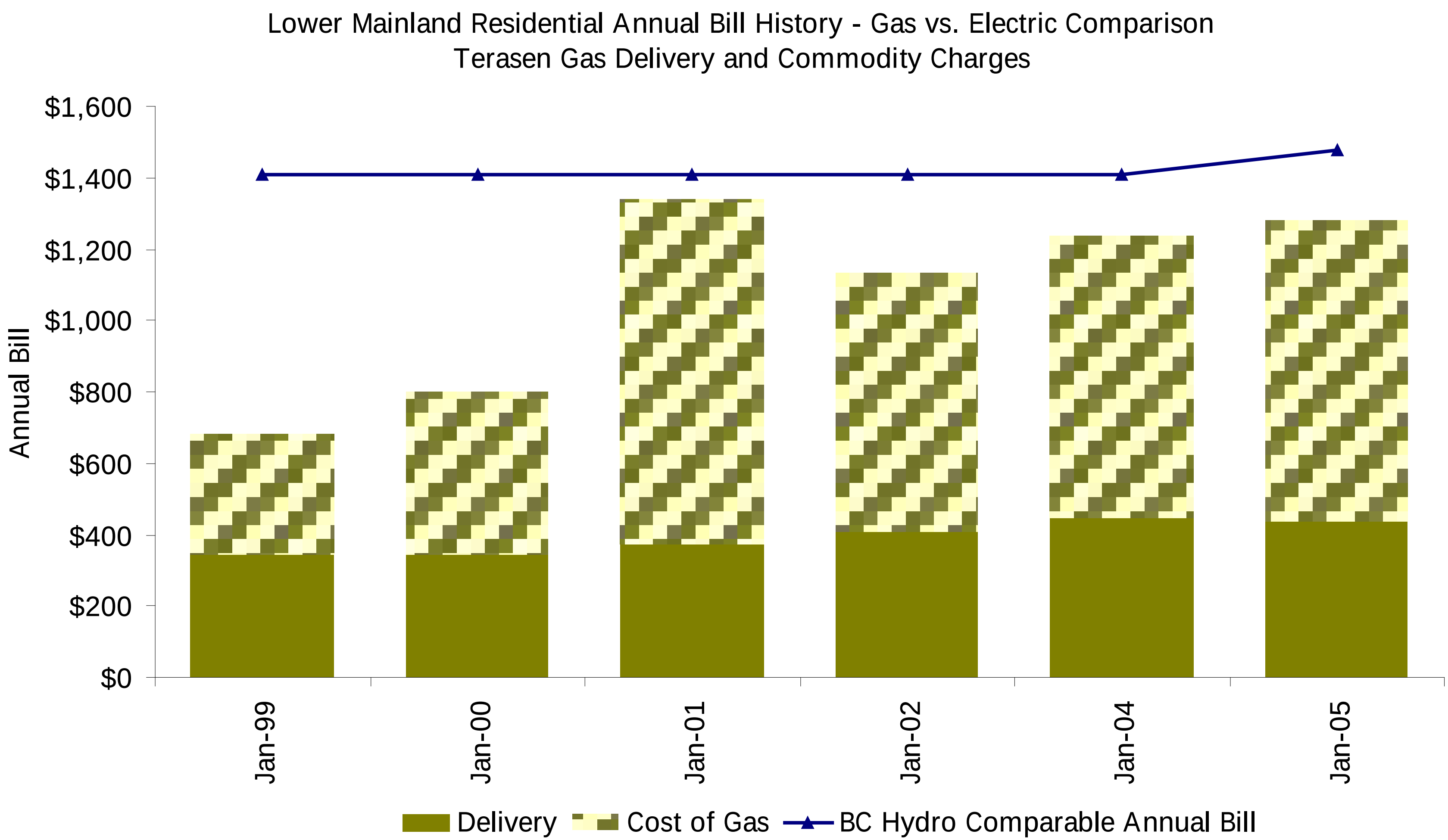
Price Competitiveness



Regulatory Arrangements

- 2004-2007 PBR in place for Terasen Gas
  - O&M and capital cost incentives, 50/50 sharing
  - Numerous deferral accounts
- 2003-2005 PBR in place for TGVI
  - O&M incentives, no sharing
  - Comprehensive deferral arrangements through Revenue Deficiency Deferral Account
  - Preference is to obtain a two-year extension to align regulatory calendar with Terasen Gas

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Regulatory Arrangements

- ROE and Capital Structure hearing planned for Q3 2005
  - Allowed returns and equity components in B.C. are exceptionally low compared to other Canadian jurisdictions
    - April 2005 consensus forecast (if unchanged in November) would result in ROEs of 8.58% for Terasen Gas and 9.08% for TGVI in 2006
  - Since the last review in B.C. in 1999, gas/electric price competitiveness has narrowed significantly
- Good opportunity to present a case for higher ROE and/or equity components

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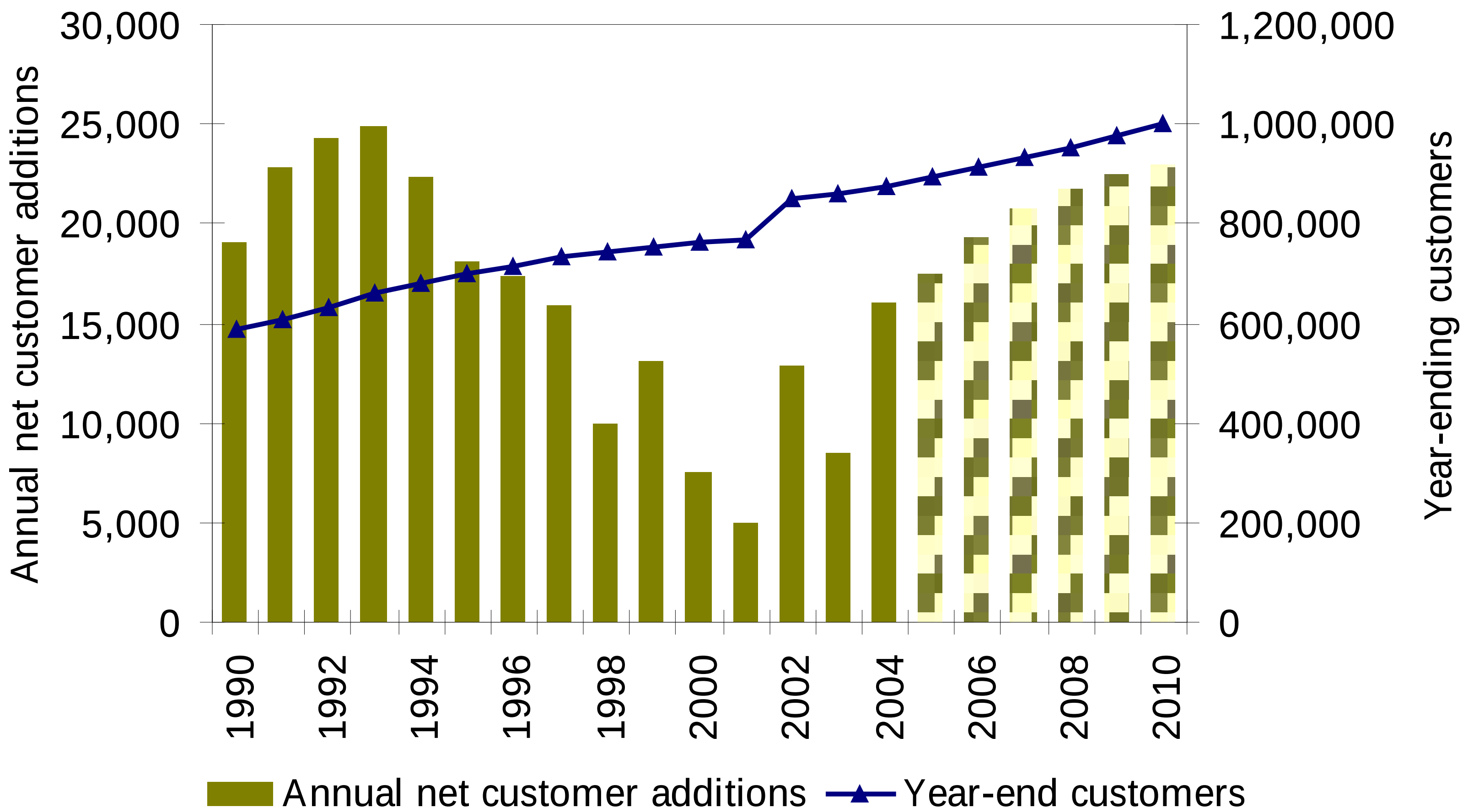
Terasen Gas - Outlook

- Successful efforts to improve operating efficiency in the past has limited the scope for future efficiencies
- Focus will be on increasing customer capture rates
  - Target of 1 million gas customers in 2010 (up from 878,000 currently)
  - Opportunity to improve capture rates for multi-family housing starts
  - Regional economy remains very strong
- Additional target of $1 billion in new investment by 2010

Customer Growth



*Data prior to 2002 excludes TGVI

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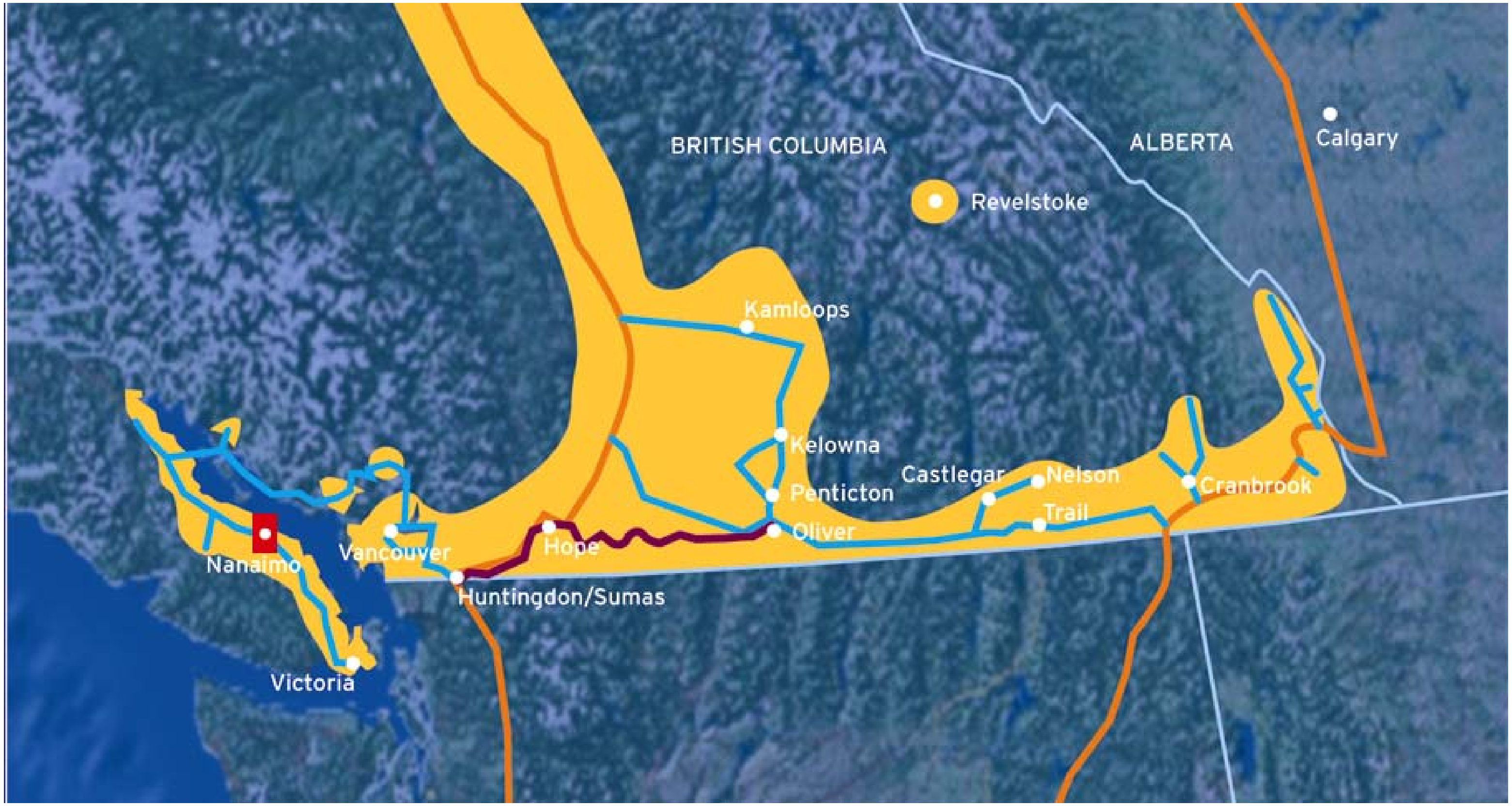
New Infrastructure Projects



- Terasen Transmission Lines
- Terasen Distribution Service Area
- Other Natural Gas Lines
- Proposed Inland Pacific Connector Pipeline
- Proposed LNG Storage Tank

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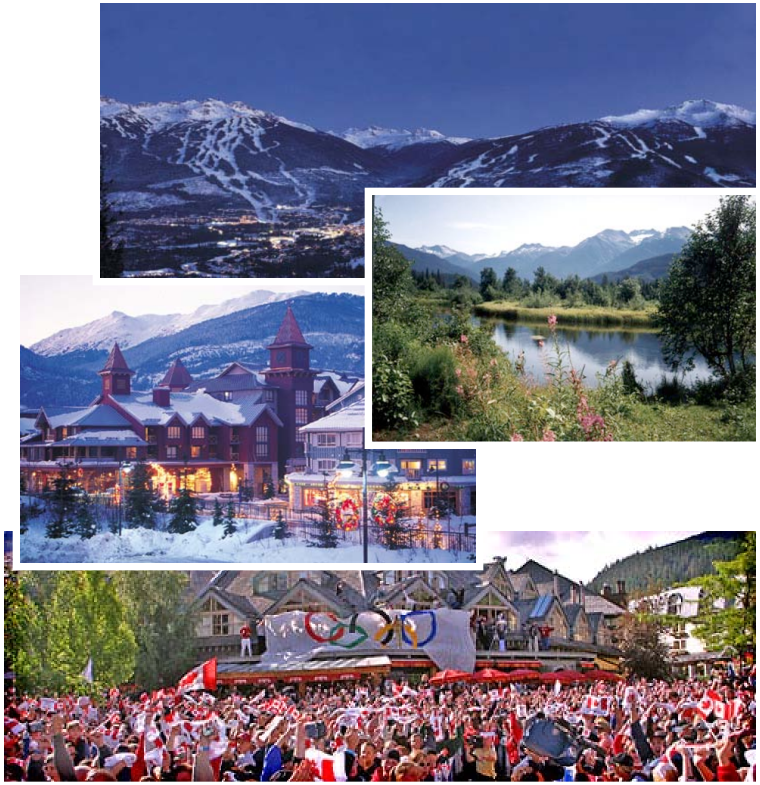
TGVI Expansion

- BCUC approved $100 mln Vancouver Island LNG Project subject to Duke Point power plant proceeding
- New LNG facility plus $50 mln compression expansion will be supported by long-term, take-or-pay contracts with BC Hydro for capacity on TGVI
- BCUC approval of Duke Point currently subject to appeal
  – Resolution expected in June
  – Initial request for leave to appeal was rejected

Growth – Whistler

- Working with the Resort Municipality of Whistler to develop a Sustainable Energy Strategy
  - Establish a hybrid gas/GSHP energy utility
  - Construct a natural gas pipeline from Squamish to Whistler
  - Develop renewable district energy systems or other sustainable options
- Estimated pipeline cost – $35 million
- Model for integrating natural gas with renewable energy sources



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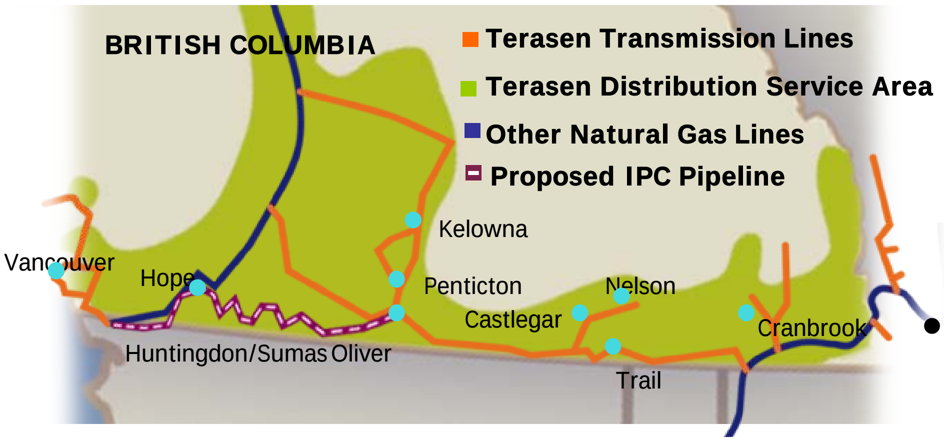
Inland Pacific Connector



- Potential $300 to $500 mln gas transmission line connecting SCP to the Lower Mainland & Sumas (NWPL)
- Project will require support from multiple shippers to move forward
- Increasing tolls on Duke System improving competitiveness

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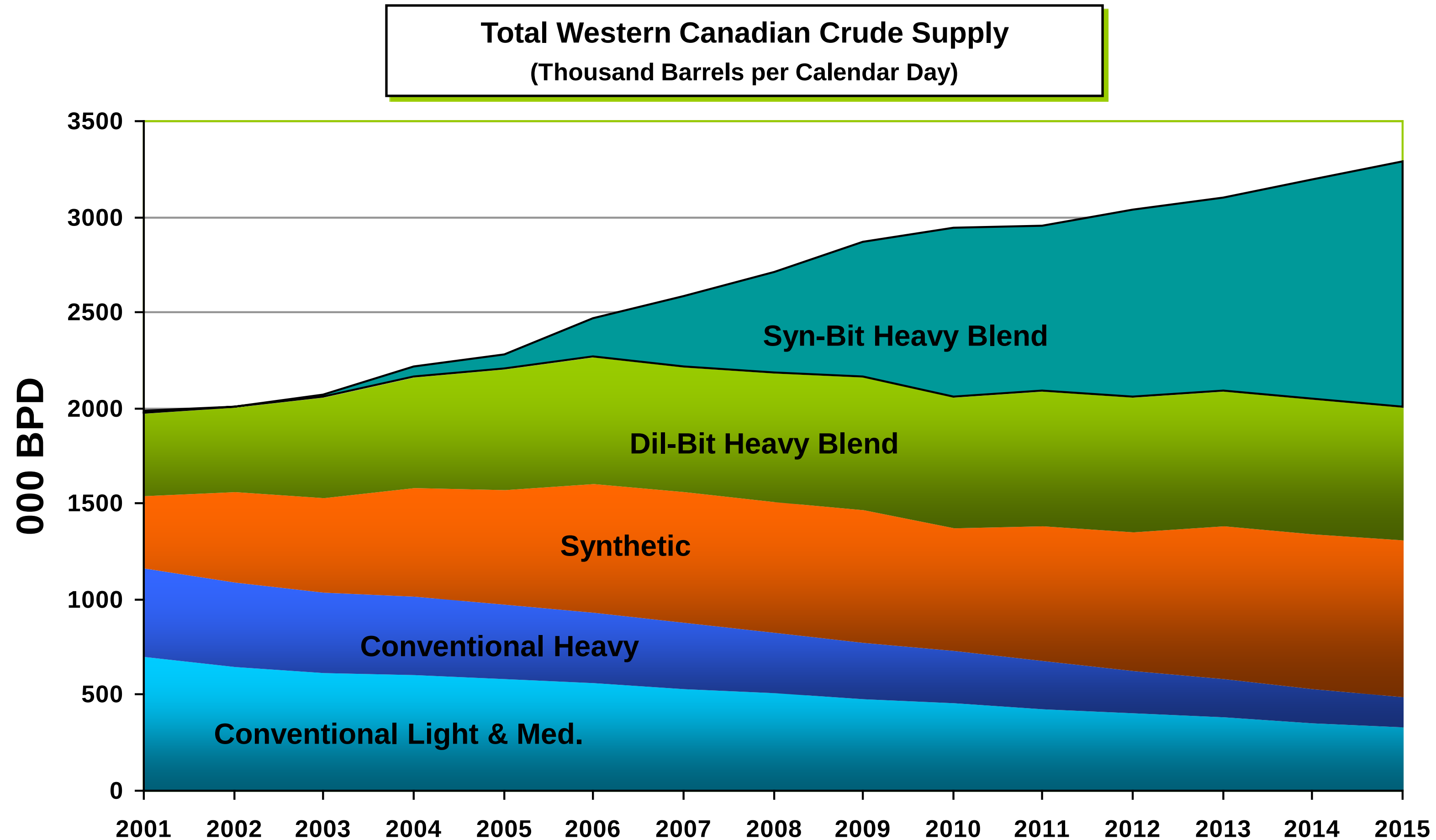
Terasen
Pipelines

Terasen Pipelines

Petroleum Pipelines   Alberta Oil Sands Deposits

Canadian Crude Supply Forecast

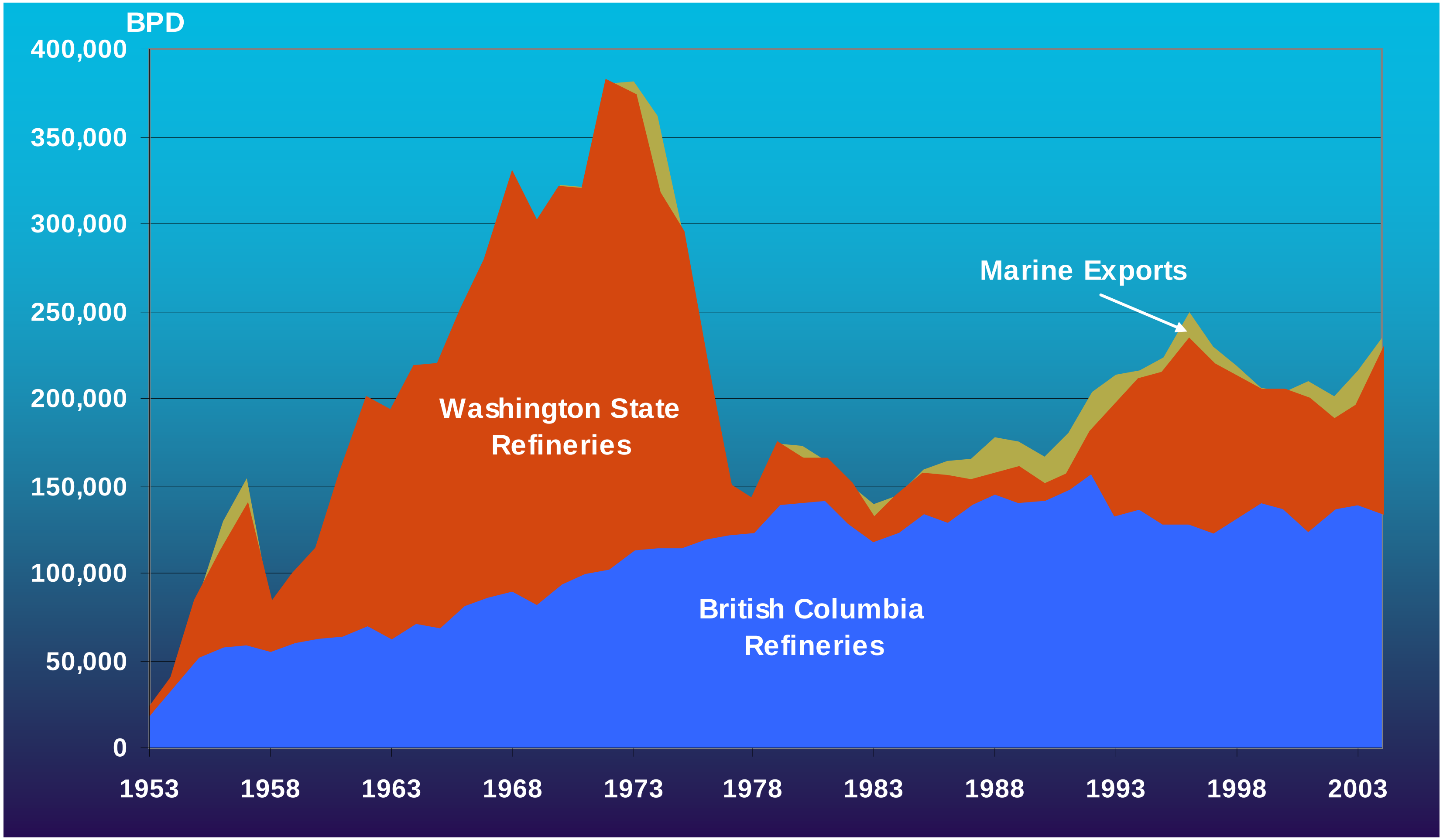


CAPP Upper Supply Case – Total Supply

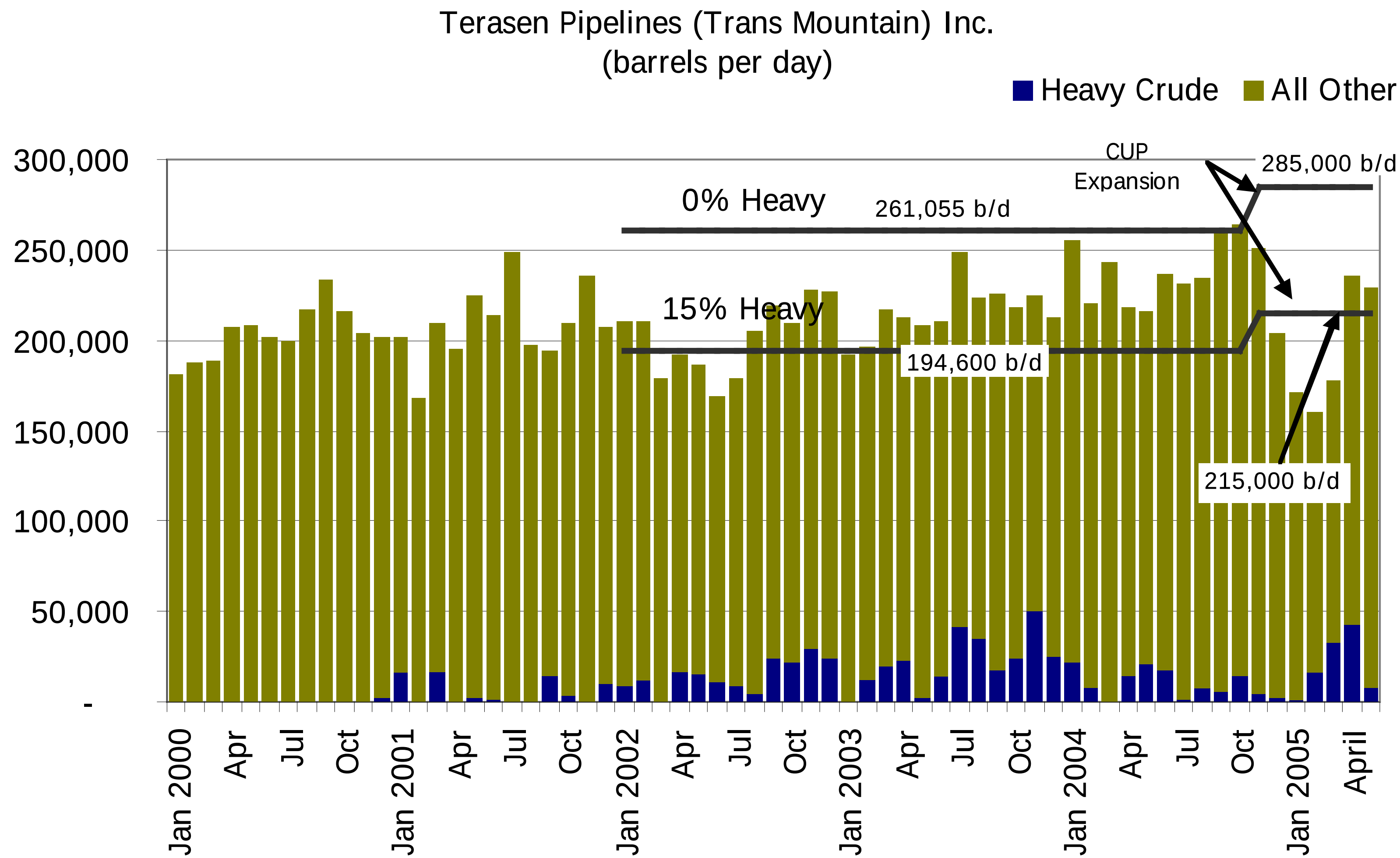
Trans Mountain - Regulatory

- Throughput growth has resulted in attractive returns from the 2001-2005 Incentive Toll Settlement
- ITS renewal discussions are underway
- Opportunity to meet shipper needs for more pipeline capacity provides negotiating flexibility

Trans Mountain Throughput



Trans Mountain Throughput



*May 2005 throughput based on forecast

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Trans Mountain Throughput

- First quarter throughput affected by "perfect storm":
  - Outages at both Syncrude and Suncor
  - Maintenance turnarounds at Chevron refinery and the Washington State refinery that takes the most Canadian crude
- April and May throughput has returned to apportionment
  - Despite continuing supply issues from the oilsands, and additional throughput on the Express system
  - Significant interest in tanker loadings in May

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Trans Mountain Expansion

- Oil sands production driving throughput growth
- Expansion can provide producers with greater access to California & Far East markets
- Completed 27,000 bpd expansion of the mainline at a cost of $19 million in October 2004

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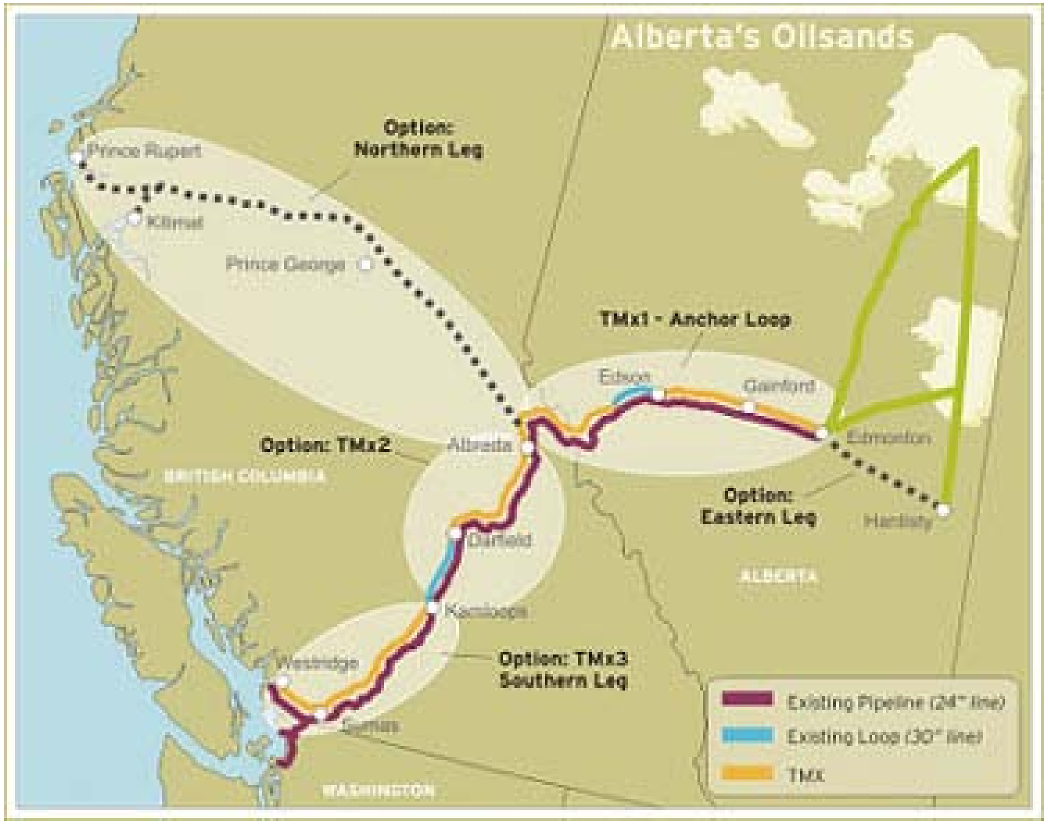
TMX Expansion



- Oilsands supply is actively seeking new markets
- Match with continued import growth on U.S. West Coast and Asia
- Expressions of Interest from potential shippers confirm demand for new capacity

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TMx1 Expansion – Two Components

TMx1 Expansion – Two Components

- Pump Station Expansion Project
  - $205 million to add 35,000 bpd of pumping capacity for 2006
  - Currently discussing expedited shipper approvals
- Anchor Loop Project
  - $365 million to loop pipeline (40,000 bpd additional capacity) for 2008
  - Actively pursuing commercial discussions with shippers
  - Open season targeted for Q2/05

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TMX Expansion

- Further 550,000 bpd capacity to either Northern or Southern port
- TMx1 plus Southern option C$2.3 billion
- TMx1 plus Northern option C$2.6 billion
- Full range of potential options to match marketing plans of Producers

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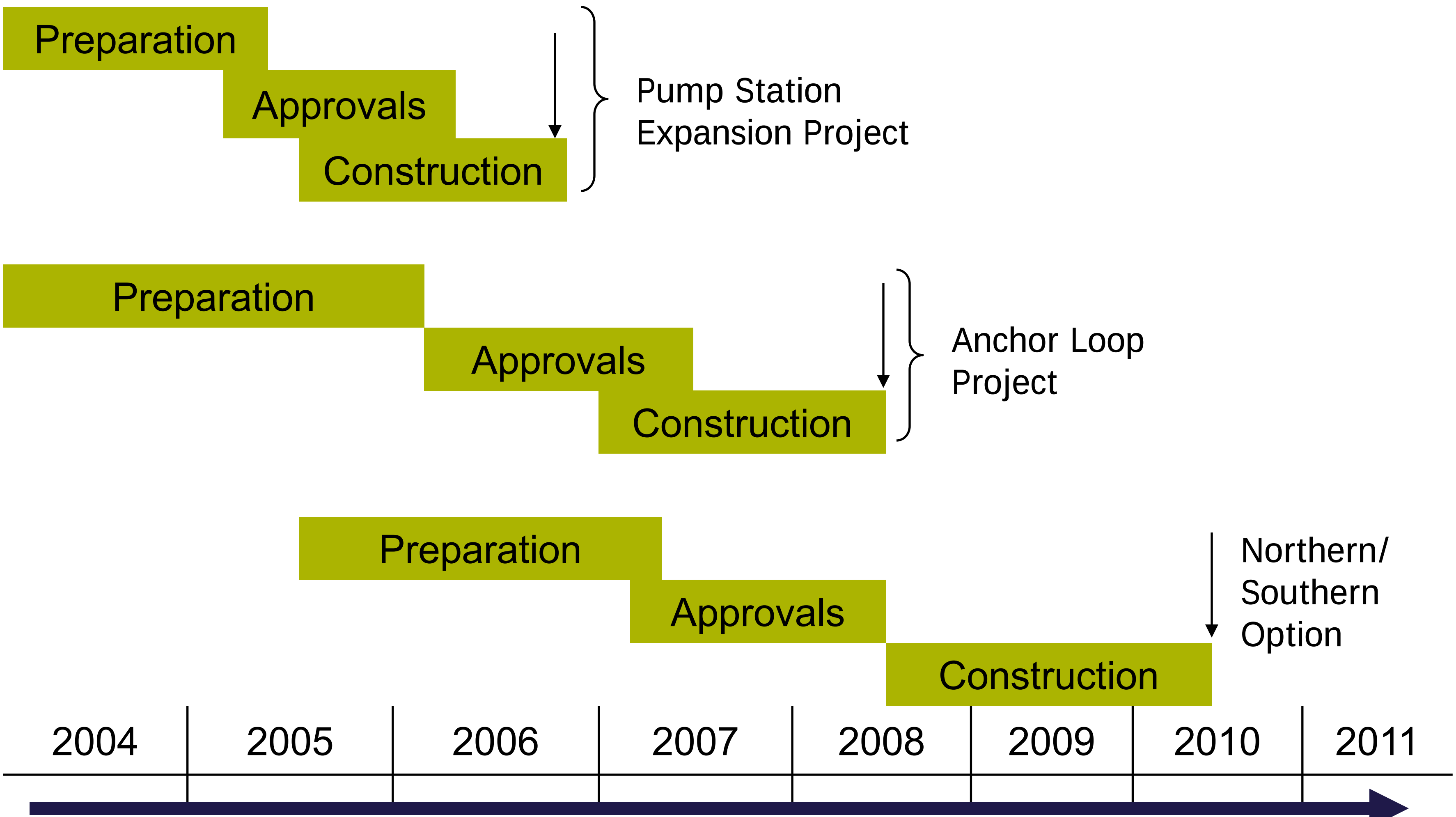
TMX Timing



Preparation
Approvals
Construction
Pump Station Expansion Project
Preparation
Approvals
Construction
Anchor Loop Project
Preparation
Approvals
Construction
Northern/ Southern Option
2004
2005
2006
2007
2008
2009
2010
2011

Corridor

- Completed on time and on budget in May 2003.
- Backed by 25 year ship-or-pay contract with Shell Canada (60%), Chevron (20%) and Western Oil Sands (20%).
- Provides for recovery of all operating costs, depreciation, taxes and financing costs in revenue requirement.
- 26% equity component, ROE is long-term Canada's plus 350 bps

Corridor Expansion

- Linked to expansion plans for Athabasca Oil Sands Project
  - > Increase bitumen production to 290,000 bpd by 2010
- Will require looping of Corridor system
- Estimated cost $700-800 million, depending on configuration
- Opportunities for third party shipper volumes
- Status: Examining options with Corridor shippers

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Express

- Acquired January 2003
- 84% of the 280,000 post-expansion capacity is committed through long-term contracts.
- Express expansion
  - Feeds PADD IV demand
  - In-service April 2005
    - On-time and under budget

Express – Business Developments

- Tie-in to Billings
  - $8 million project to interconnect with the ExxonMobil Silvertip Pipeline
  - Additional 14k bpd 10-year contract signed to support tie-in
- Platte de-bottlenecking
  - $6 million project to enhance capacity of the Platte pipeline and facilitate flows to PADD II
- Currently examining options for further expansion of the Express System, including new looping

Contracted Capacity

Summary by Shipper

Shipper	Credit Rating	2007	2012	2014	2015
Alberta Government	AAA		15,000		
Canadian Natural	BBB+	3,000	3,000		
ConocoPhillips	A-		10,000	30,000	25,000
EnCana Crude Mktg.	BBB+		70,000		
[ ]	AAA				14,000
[ ]	BB		13,800		10,000
Sinclair Oil*	AAA				10,000
Suncor Energy	A				30,000
Talisman Energy	BBB+	1,000			
Total		4,000	111,800	30,000	89,000

*Internal rating

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Expansion Financing

- Excess proceeds of $10 million are being used to fund small expansions noted previously
- Process of converting Notes from Holdings level to System level is underway
- Result is that an additional $110 million of 6.09% Senior Secured Notes due January 2020 will be outstanding at the Express system level

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Express – Financing Plans

- Future looping plans are preliminary, so financing requirements and plans are yet to be determined
  - Expansion will be financed prudently, based on business risk and contractual support
- Small amounts of additional debt may be raised at a holdco level, with no impact on the existing Trust Indenture
  - Mainly to replace a component of scheduled amortization on initial notes

Terasen
Water & Utility Services

Water and Utility Services

- Western Canada's private sector market leader providing water/wastewater infrastructure services
- Primary operator for outsourced utility services
- Operates over 90 systems in over 50 communities

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Water and Utility Services

- Fairbanks acquisition
  - Acquired a 50% interest in the water and sewer utility that serves Fairbanks, Alaska for C$40 million
  - Fairbanks is an example of the private water utility model that Terasen is developing in Western Canada
    - Regulated by the Regulatory Commission of Alaska
    - 70% deemed equity component, 13.8% allowed ROE in most recent revenue requirement decision

Terasen Gas Inc.

Presentation to DBRS

March 28, 2008

Contact Information

Roger Dall'Antonia
VP, Corporate Development & Treasurer
Terasen Inc.

Tel: (604) 443-6570
roger.dall'antonia@terasen.com

Presentation Overview

- Corporate Overview
- Terasen Gas Overview

Terasen Gas Overview

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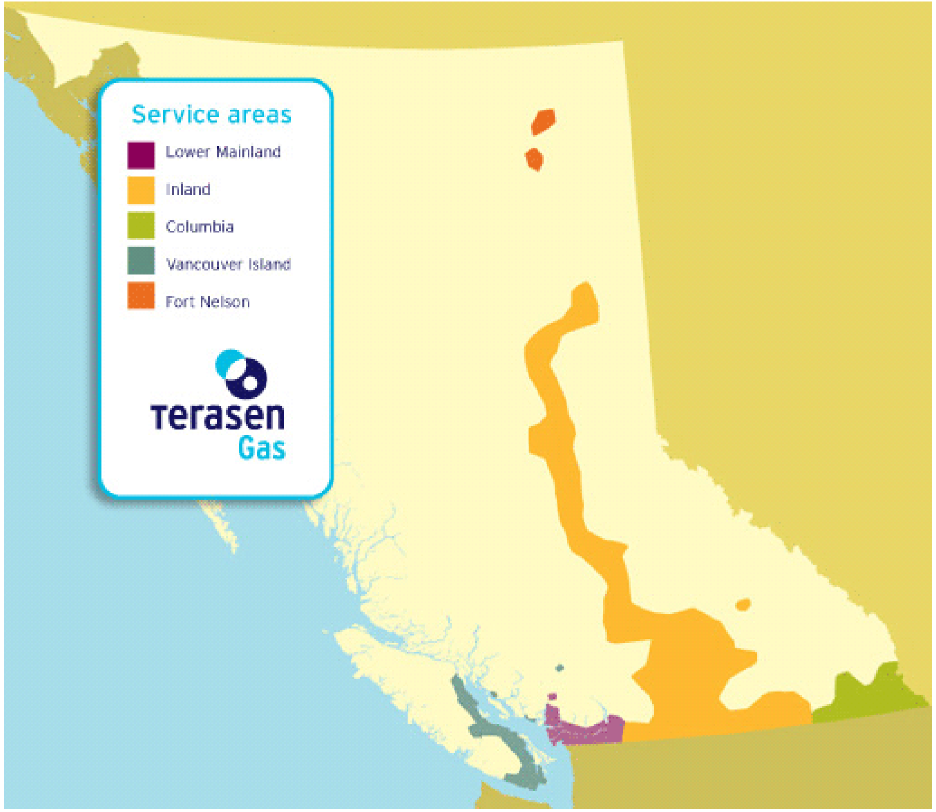


* Map includes TGVI service areas

- Terasen Gas Inc. is a regulated natural gas transmission and distribution utility
  - Providing service to lower mainland, interior and northern areas of BC
  - Customer base of ~825,000
  - Rate base of ~$2.5 billion
- Experienced management team with significant energy industry expertise
- Strong ownership provide by Fortis Inc.
- Sister company to Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.
  - Combined, the three entities provide service to over 900,000 customers, ~96% of natural gas users in BC
  - TGI, TGVI and TGW share a common management and administrative structure with the cost allocation reviewed by BCUC
- Operates within a supportive regulatory environment, under the British Columbia Utilities Commission

Experienced Management Team

Terasen

Randy Jespersen
President & CEO

Doug Stout
VP, Marketing & Business Development

Jan Marston
VP, Gas Supply & Transmission

Dwain Bell
VP, Distribution

Daryle Britton
VP, Human Resources & Operational Governance

Bob Samels
VP, Business Services & CIO

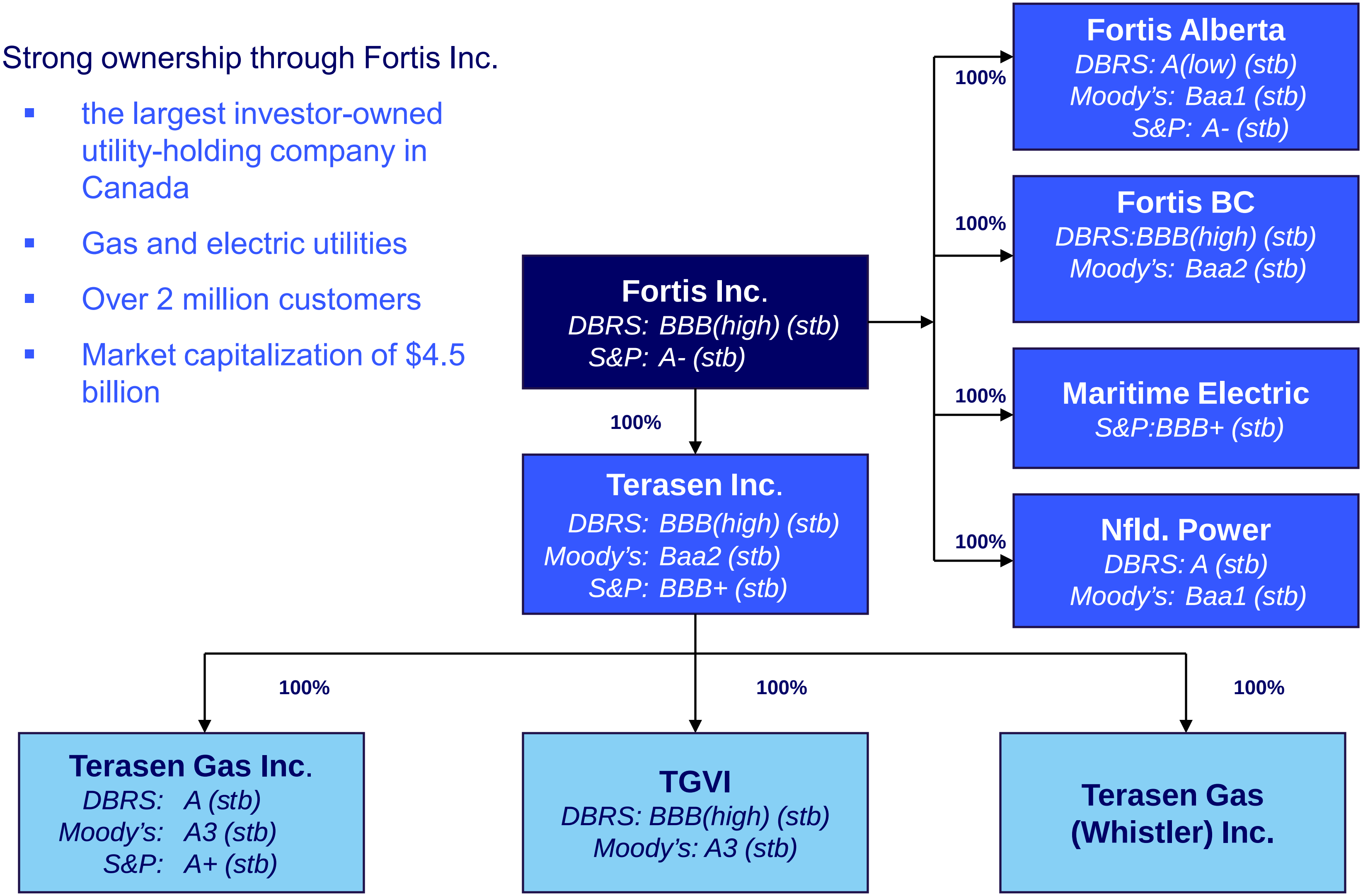
Scott Thomson
VP, Regulatory Affairs & CFO

David Bennett
VP, General Counsel

Roger Dall'Antonia
VP, Corporate Development & Treasurer

Strong Ownership

- Strong ownership through Fortis Inc.
  - the largest investor-owned utility-holding company in Canada
  - Gas and electric utilities
  - Over 2 million customers
  - Market capitalization of $4.5 billion

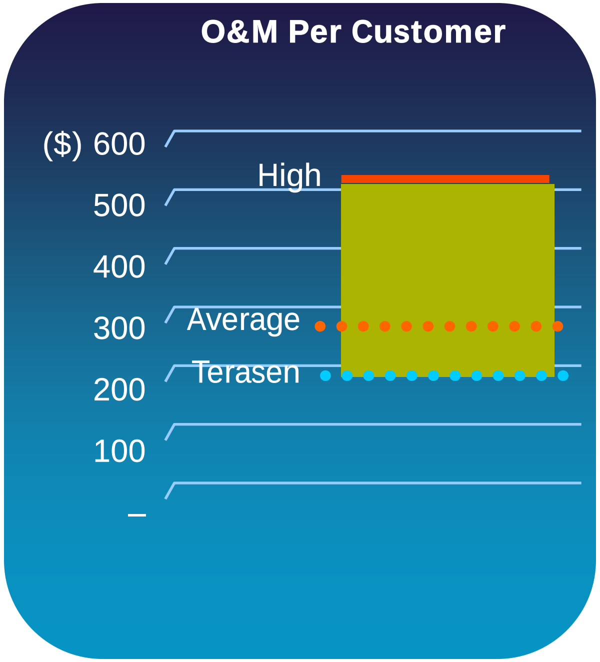


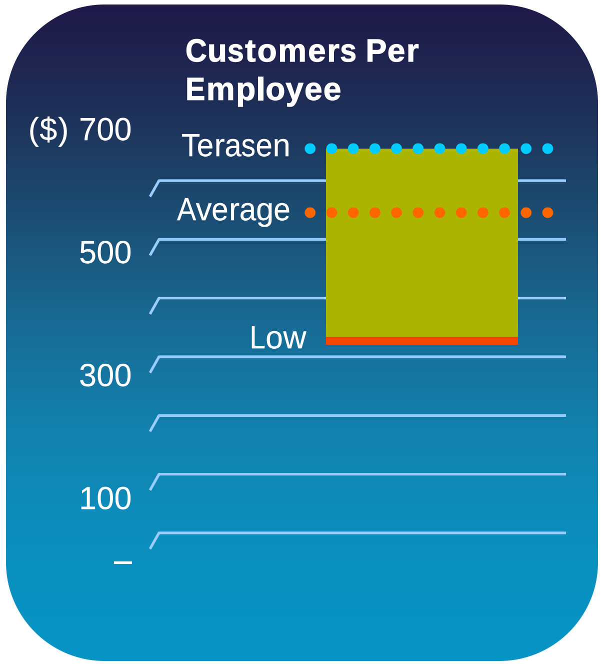
2007 Highlights

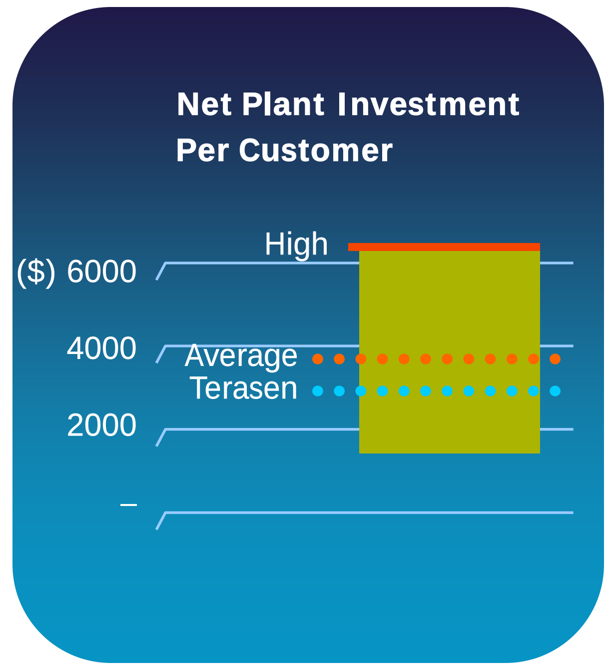
Terasen

- Net Income of $78.2 million compared to $68.4 million for 2006
  - Surplus land sale, O&M and capital efficiencies offset lower allowed ROE
  - 2007 allowed ROE at 8.37% compared to 8.80% for 2006
- Continued customer growth due to population growth and economy
  - Net customer additions of ~10,000, similar to 2006
- Extension of PBR construct for 2008-2009 period
  - Incentive mechanism in place
  - Continuation of use of regulatory deferral accounts
- Amalgamation of Terasen Gas (Squamish) on blended rate base
- Issuance of $250 million debt during difficult market conditions
- Extended $500 million syndicated credit facility, including $100 million accordion feature allowing for rapid access to operating credit

Operating Efficiency



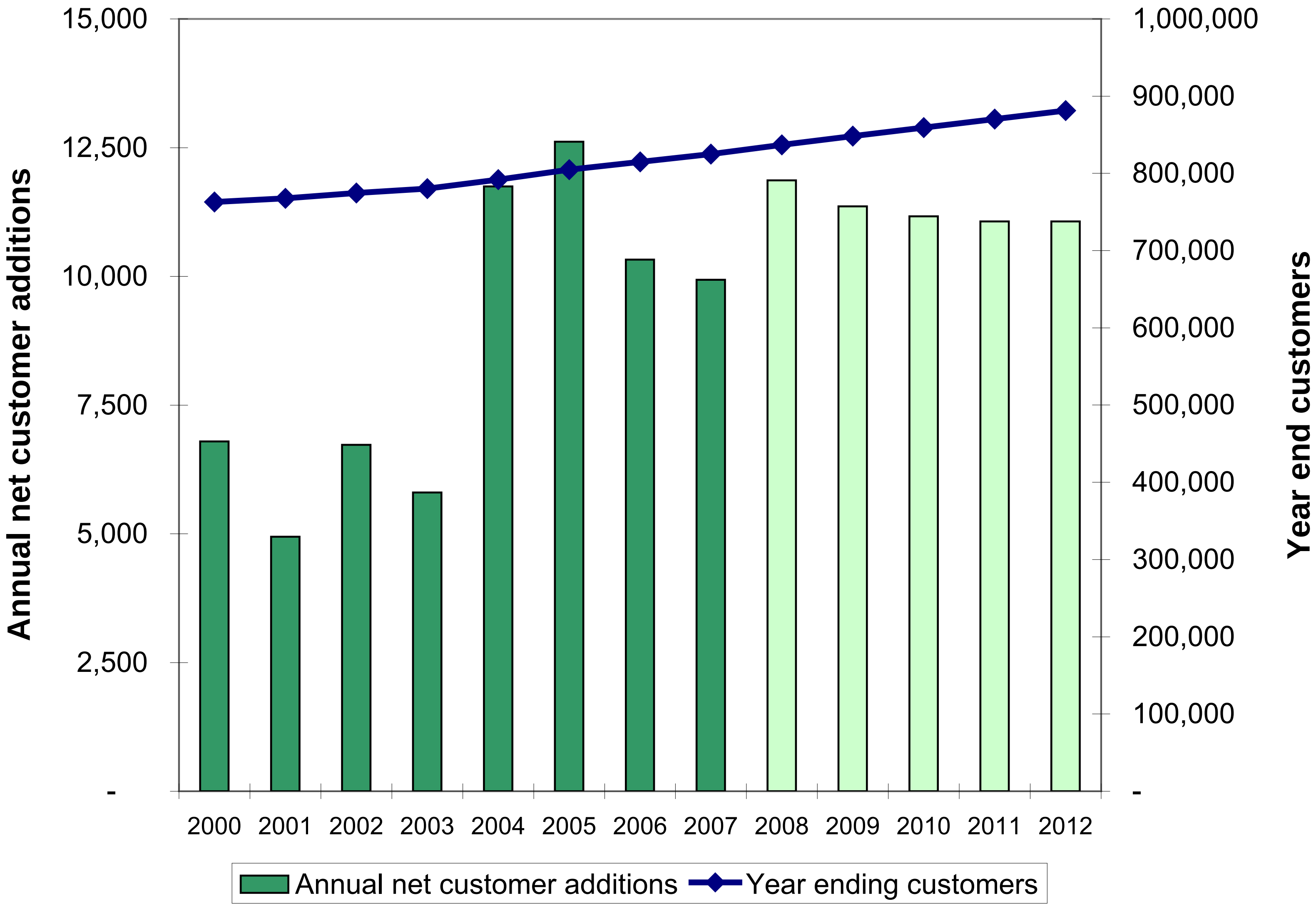




Source: LSM Consulting

Terasen Gas Estimates including TGI and TGVI

Customer Growth



Price Competitiveness

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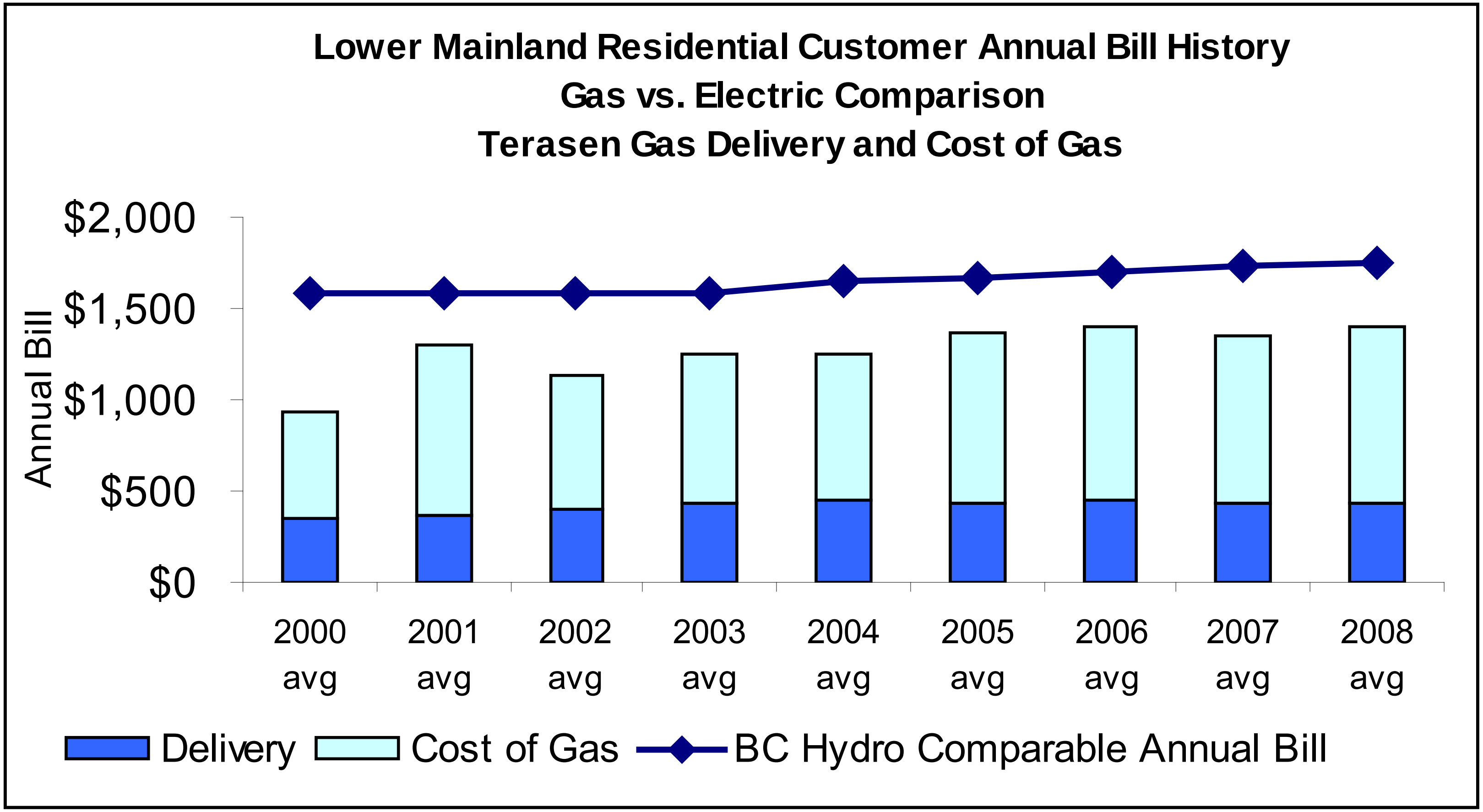
- Terasen Gas maintains a price advantage relative to electricity, the primary competitor to natural gas
- Increases in the market price of natural gas, combined with subsidized electricity prices, have in recent years eroded the historical advantage over electricity
- Terasen Gas maintains an active price risk management program (on behalf of customers with BCUC approval) which mitigates this risk
- Terasen Gas focus on operational efficiency has kept delivery charge component relatively flat over the last five years
- Introduction of Carbon Tax plus pressure on natural gas prices will create competitive pricing pressures
- BC Energy Plan focus on emission reduction and "clean-power" is expected to result in larger increases in electricity rates relative to recent experience

Price Competitiveness



Regulatory Arrangements

- 2004-2007 PBR previously in place for Terasen Gas extended through 2009
  - O&M and capital cost incentives, 50/50 sharing
  - Continuation of numerous deferral accounts
- Equity component for TGI 35.01% (post Terasen Squamish roll-in)
- Allowed ROE formula
  - 3.90% premium over forecast 30 year GoC yield
  - Risk premium adjusted by 75% of change in forecast yield year over year
  - 2008 allowed ROE set at 8.62%, up from 8.37% allowed ROE for 2007

BCUC Ring Fencing

- BCUC in April 30, 2007 Order approving the Fortis acquisition specified certain ring-fencing conditions
  - Maintain a common equity to total capital ratio at least as high as the level determined by BCUC
  - No dividends without BCUC approval if equity:capital ratio would be violated
  - Restrictions on interaction with affiliates (separate cash management, no financial support, no tax sharing, transactions only on an arms length basis)
  - No financial support or guarantee of non-regulated businesses
  - Maintain existing governance policies, in particular, independence of Directors

Terasen Gas - Outlook

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- Financial performance will continue to be predictable
- Focus will be on increasing customer capture rates and retaining customers
  - Opportunity to focus on multi-family dwellings
  - Regional economy remains strong, expected to continue through 2010
- Focus on retaining customers through expanded energy conservation and efficiency programs
- Pursuing fair return for natural gas utilities in Canada
  - 2008 allowed ROE 8.62%, up from 8.37% 2007
- Planning underway for potential replacement of current PBR
- Infrastructure opportunities focused on transmission and CIS
  - Inland Pacific Connector potential for 2012
  - Reviewing AMI/AMR infrastructure opportunities

Terasen Gas Inc.

Presentation to DBRS

April 3, 2009

Contact Information

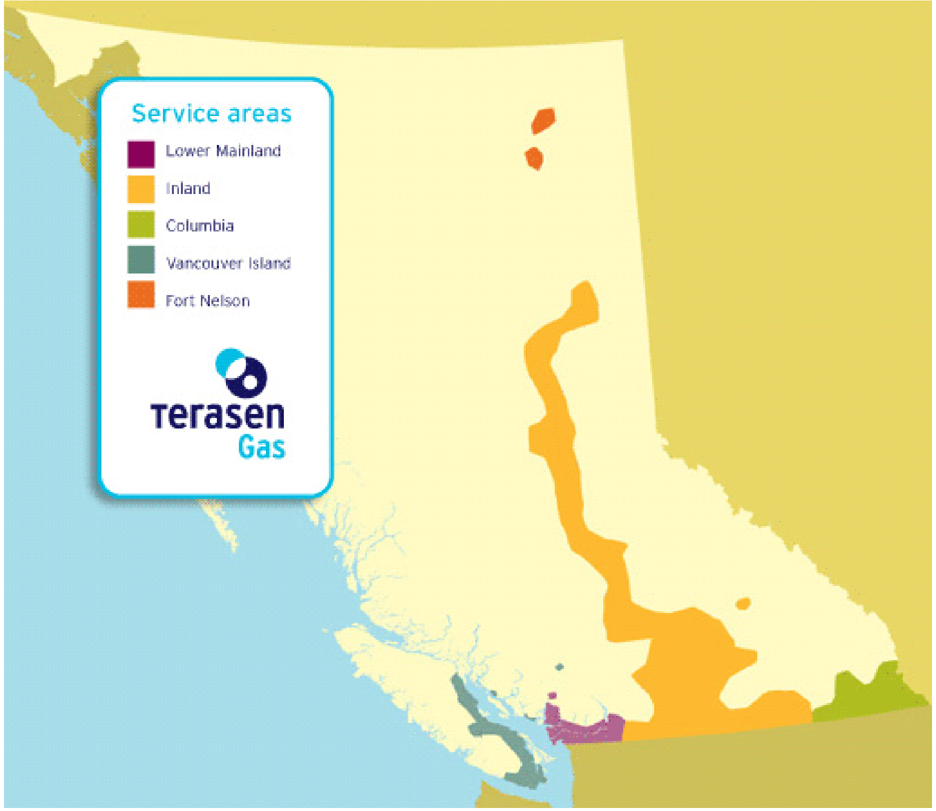
Roger Dall'Antonia
VP, Corporate Development & Treasurer
Terasen Inc.

Tel: (604) 443-6570
roger.dall'antonia@terasen.com

Presentation Overview

- Corporate Overview
- Terasen Gas Overview

Terasen Gas Overview



* Map includes TGVI service areas

- Terasen Gas Inc. is a regulated natural gas transmission and distribution utility
  - Providing service to lower mainland, interior and northern areas of BC
  - Customer base of ~834,000
  - Rate base of ~$2.5 billion
- Experienced management team with significant energy industry expertise
- Strong ownership provided by Fortis Inc.
- Sister company to Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.
  - Combined, the three entities provide service to over 931,000 customers, ~96% of natural gas users in BC
  - TGI, TGVI and TGW share a common management and administrative structure with the cost allocation reviewed by BCUC
- Operates within a supportive regulatory environment, under the British Columbia Utilities Commission

Experienced Management Team

terasen

Randy Jespersen
President & CEO

Doug Stout
VP, Marketing & Business Development

Cynthia Des Brisay
VP, Gas & Transmission

Dwain Bell
VP, Distribution

Jan Marston
VP, Human Resources & Operational Governance

Bob Samels
VP, Business Services & CIO

Scott Thomson
VP, Regulatory Affairs & CFO

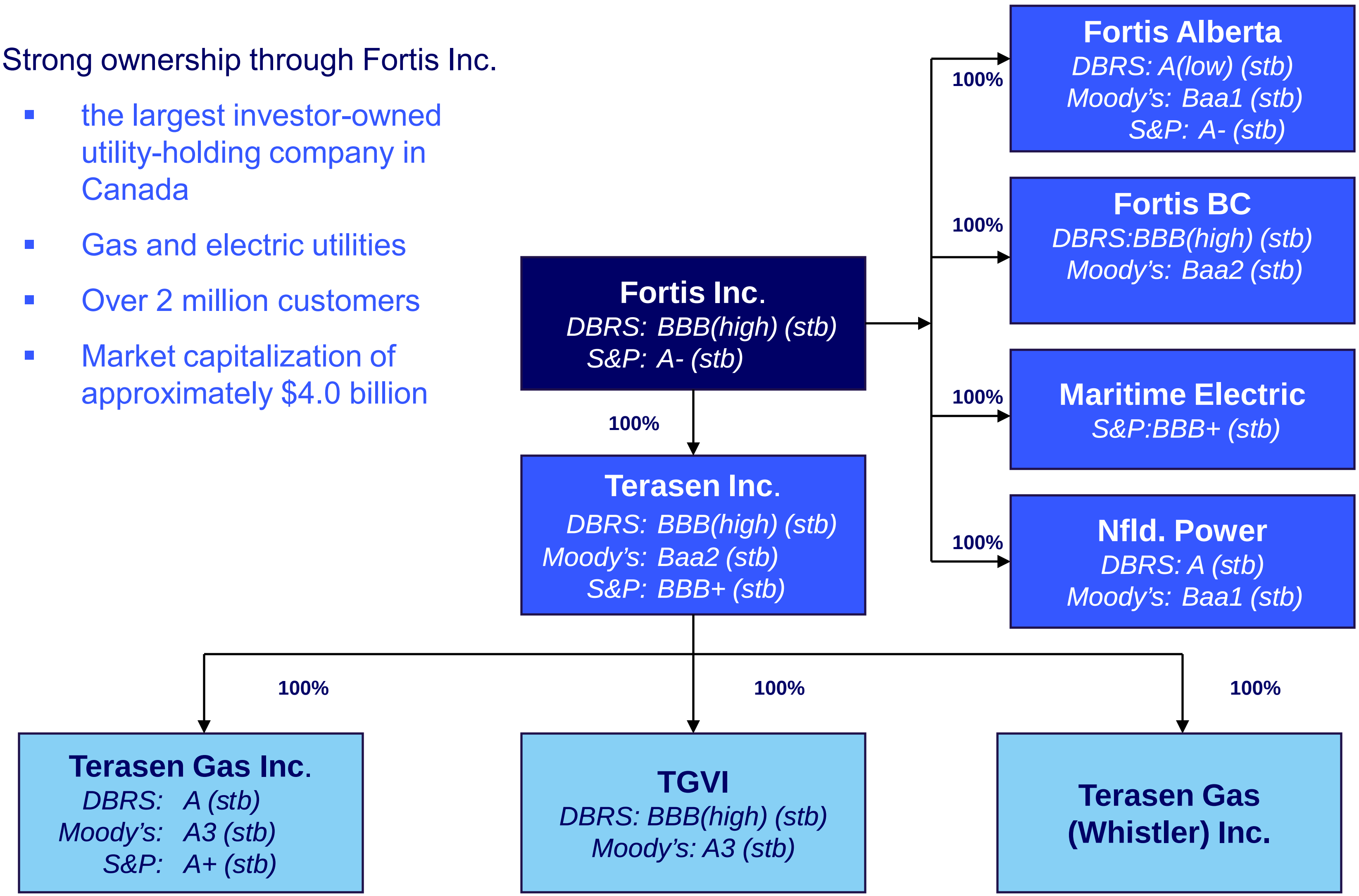
David Bennett
VP, General Counsel

Roger Dall'Antonia
VP, Corporate Development & Treasurer

Strong Ownership

terasen

- Strong ownership through Fortis Inc.
  - the largest investor-owned utility-holding company in Canada
  - Gas and electric utilities
  - Over 2 million customers
  - Market capitalization of approximately $4.0 billion



Common Management Structure

terasen

- Ownership and Operatorship
  - In addition to TGI, Terasen Inc. also owns and operates TGVI and Terasen Gas (Whistler) (“TGW”), which provides service to the Whistler region

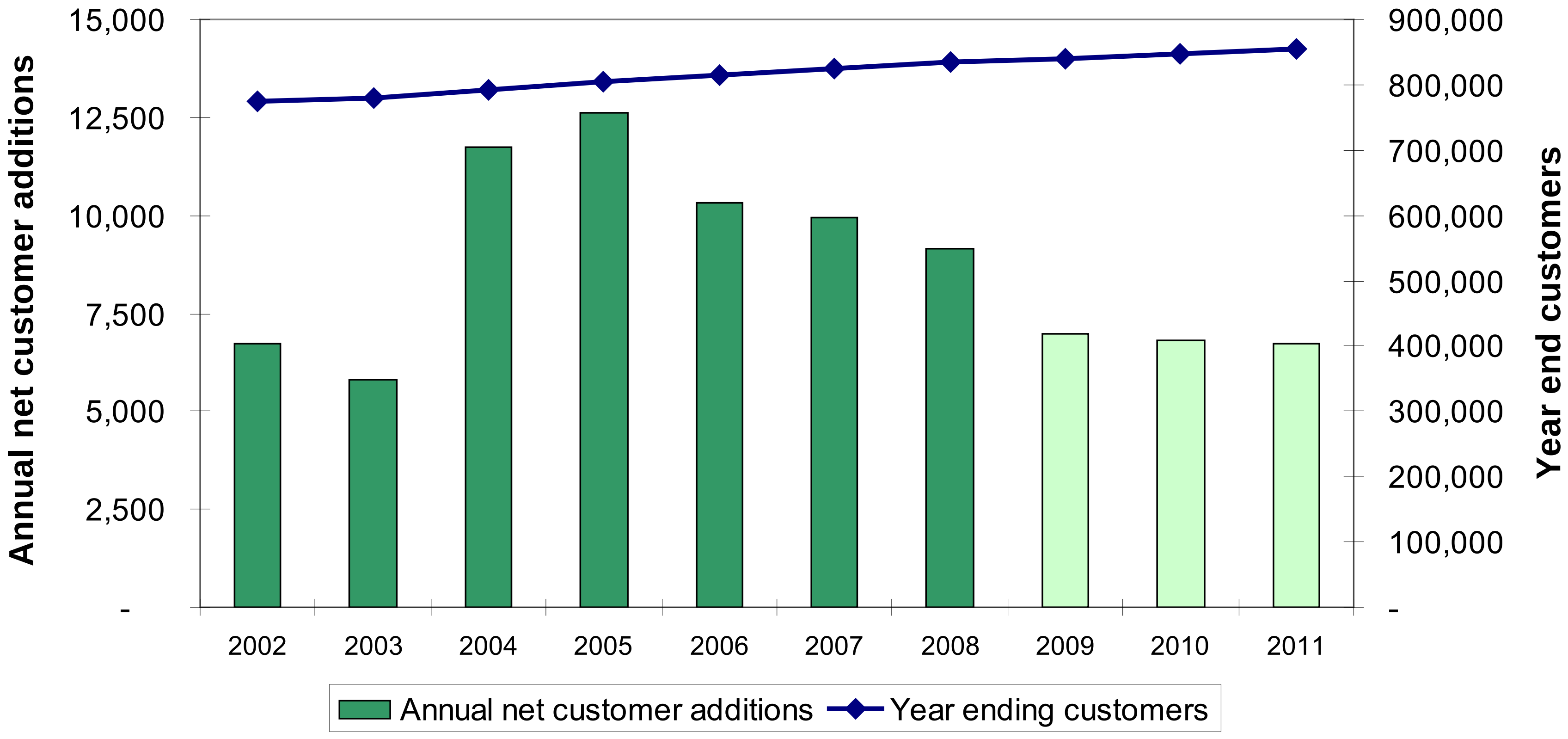
	TGI	TGVI	TGW	Total
Customers	**834,226**	**94,778**	**2,457**	**931,461**
% BC Natural Gas Users	**86%**	**10%**	**<1%**	**~96%**
Pipeline Network (km)	**39,899**	**6,098**	**132**	**46,129**
2009 Estimated Rate Base (mm)	**$2,547**	**$514**	**$39**	**$3,100**
Assets (mm)	**$3,109**	**$697**	**$24**	**$3,830**

  - TGI, TGVI and TGW share a common management and administrative structure with the cost allocation reviewed by BCUC

2008 Highlights

- Net Income of $91.5 million compared to $78.2 million for 2007
  - 2008 results include settlements with CRA of $11.6 million
  - 2008 allowed ROE at 8.62% compared to 8.37% for 2007
- Continued customer growth but a lower rate of additions due to a slowing economy in British Columbia
  - Net customer additions of ~9,000
- Extension of PBR construct for 2008-2009 period
  - Incentive mechanism in place
  - Continuation of use of regulatory deferral accounts
- Issuance of $250 million debt in 2008
- Extended existing $500 million syndicated credit facility by one year to 2013

Customer Growth

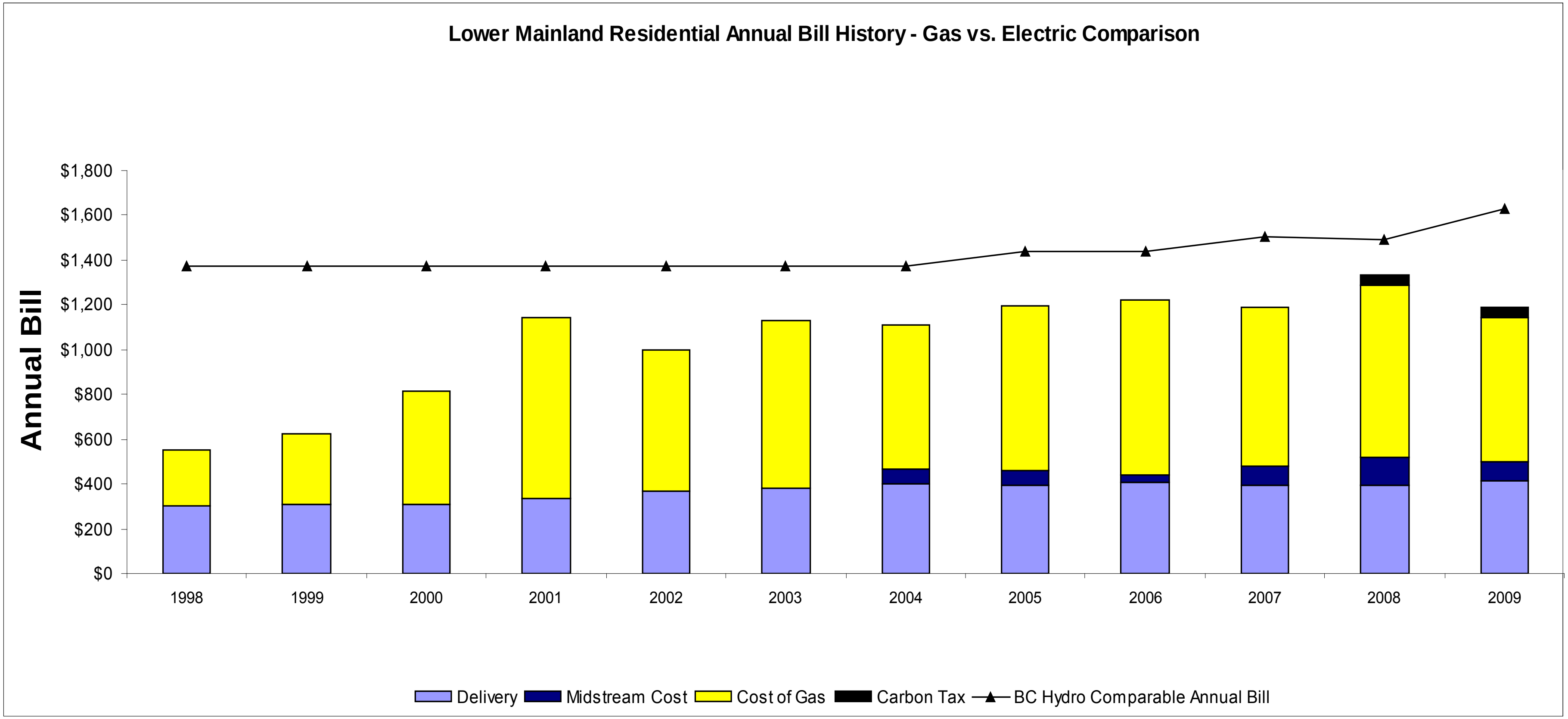


Price Competitiveness

- Terasen Gas maintains a price advantage relative to electricity, the primary competitor to natural gas
- Increases in the market price of natural gas, combined with subsidized electricity prices, have in recent years eroded the historical advantage over electricity
- Terasen Gas maintains an active price risk management program (on behalf of customers with BCUC approval) which mitigates this risk
- Terasen Gas focus on operational efficiency has kept delivery charge component relatively flat over the last five years
- BC Energy Plan focus on emission reduction and “clean-power”:
  - Expected to result in larger increases in electricity rates relative to recent experience;
  - However emmissions reduction focus will put pressure on natural gas demand

Price Competitiveness

Terasen



Assumes:

Natural gas use of 95 GJ

Efficiency of gas equipment is 90% relative to 100% for electricity

Terasen Gas amount includes the basic charge

BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

Regulatory Arrangements

- 2004-2007 PBR previously in place for Terasen Gas extended through 2009
  - O&M and capital cost incentives, 50/50 sharing
  - Continuation of numerous deferral accounts
- Equity component for TGI 35.01% (post Terasen Squamish roll-in)
- Allowed ROE formula
  - 3.90% premium over forecast 30 year GoC yield at a base level of 5.25%
  - Current GoC yields suggest a lower ROE in 2010
  - Risk premium adjusted by 75% of change in forecast yield year over year
  - 2009 allowed ROE set at 8.47%, down from 8.62% allowed ROE for 2008

BCUC Ring Fencing

- BCUC in April 30, 2007 Order approving the Fortis acquisition specified certain ring-fencing conditions
  - Maintain a common equity to total capital ratio at least as high as the level determined by BCUC
  - No dividends without BCUC approval if equity:capital ratio would be violated
  - Restrictions on interaction with affiliates (separate cash management, no financial support, no tax sharing, transactions only on an arms length basis)
  - No financial support or guarantee of non-regulated businesses
  - Maintain existing governance policies, in particular, independence of Directors

Terasen Gas - Outlook

- Near term financial performance expected to be predictable
- Lower customer growth than in the past few years due to a slowing economy and fewer new housing starts
- Focus will be on increasing customer capture rates and retaining customers
- Focus on retaining customers through expanded energy conservation and efficiency programs
- Planning for ROE/Capital structure application in 2009
  - 2009 allowed ROE 8.47%, down from 8.62% 2008
  - Based on current GoC yields, formula ROE would be 7.92% as of the end of March 2009
- Planning underway for a Revenue Requirement Application in mid 2009
- In 2011, the Company will transition to IFRS and this may create significant volatility in the earnings

Presentation to Moody's Investors Service

May 2004

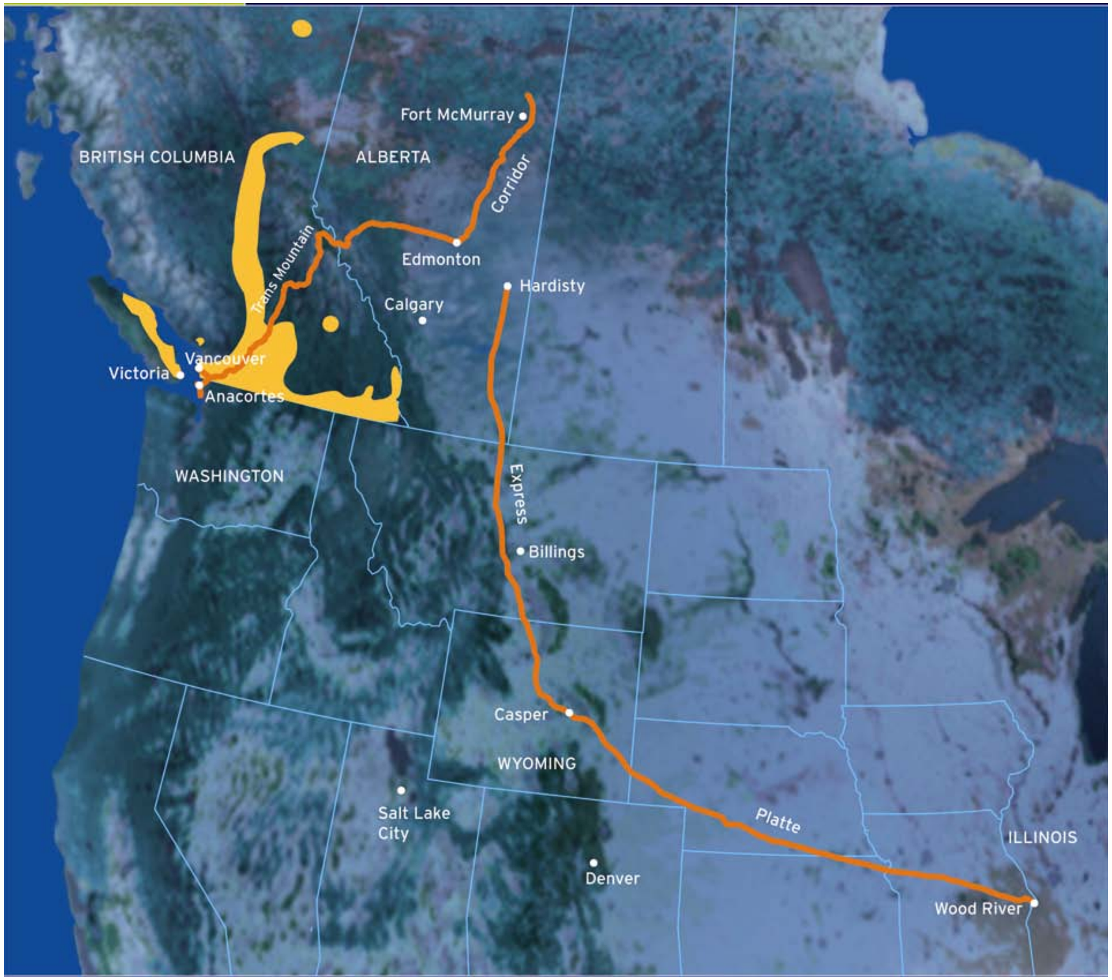
Presentation Overview

- Corporate overview
- Strategy
- Terasen Pipelines
- Terasen Gas
- Terasen Water and Utility Services
- Appendix – Municipal Leasing Transactions

Corporate Structure

- Terasen Inc.
  - Natural Gas Distribution
    - Terasen Gas
    - Terasen Gas (Vancouver Island)
  - Petroleum Transportation
    - Trans Mountain Pipeline
    - Corridor Pipeline
    - Express/Platte Pipelines (33.3% ownership)
  - Water & Utility Services
    - Terasen Utility Services
    - Terasen Waterworks
    - Customerworks (30% ownership)

Corporate Overview



Natural Gas Distribution

Petroleum Transportation

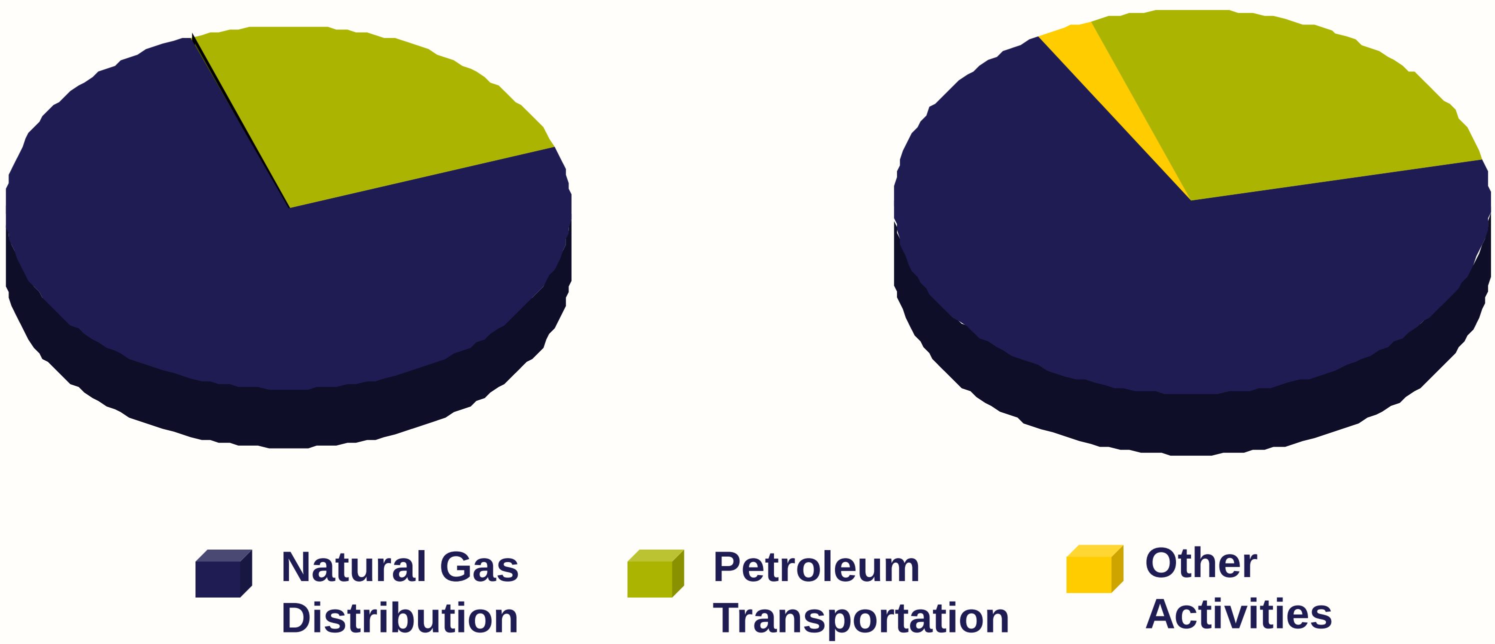
Corporate Overview

Operating Income: $366 million

(12 months ended December 31, 2003)

Assets: $4,915 million

(at December 31, 2003)



2003 Highlights

- BCUC approval of a negotiated settlement of a 2004-2007 Performance-Based Rate Plan for Terasen Gas
- BCUC approval of a 2003-2005 regulatory settlement for TGVI, which extends incentive mechanisms
- Initiation of commercial operations of Corridor in May 2003, following on time, on budget completion of its construction
- Completion of the acquisition of a one-third interest in the Express Pipeline System and shipper support for the expansion plans for Express
- Initiation of the expansion of the Trans Mountain pipeline which will add 27,000 bbl/day in capacity

Management

John Reid
President & CEO

- Gordon Barefoot
  Senior VP Finance & CFO
- Stephen Swaffield
  Senior VP
  Corporate Development
- Patrick Lloyd
  Senior VP HR &
  Governmental Affairs
- Steve Richards
  General Counsel, CRO
  & Corporate Secretary
- Randy Jesperson,
  President,
  Terasen Gas
- Richard Ballantyne
  President,
  Terasen Pipelines
- Brett Hodson
  President, TUS
  & Terasen Waterworks

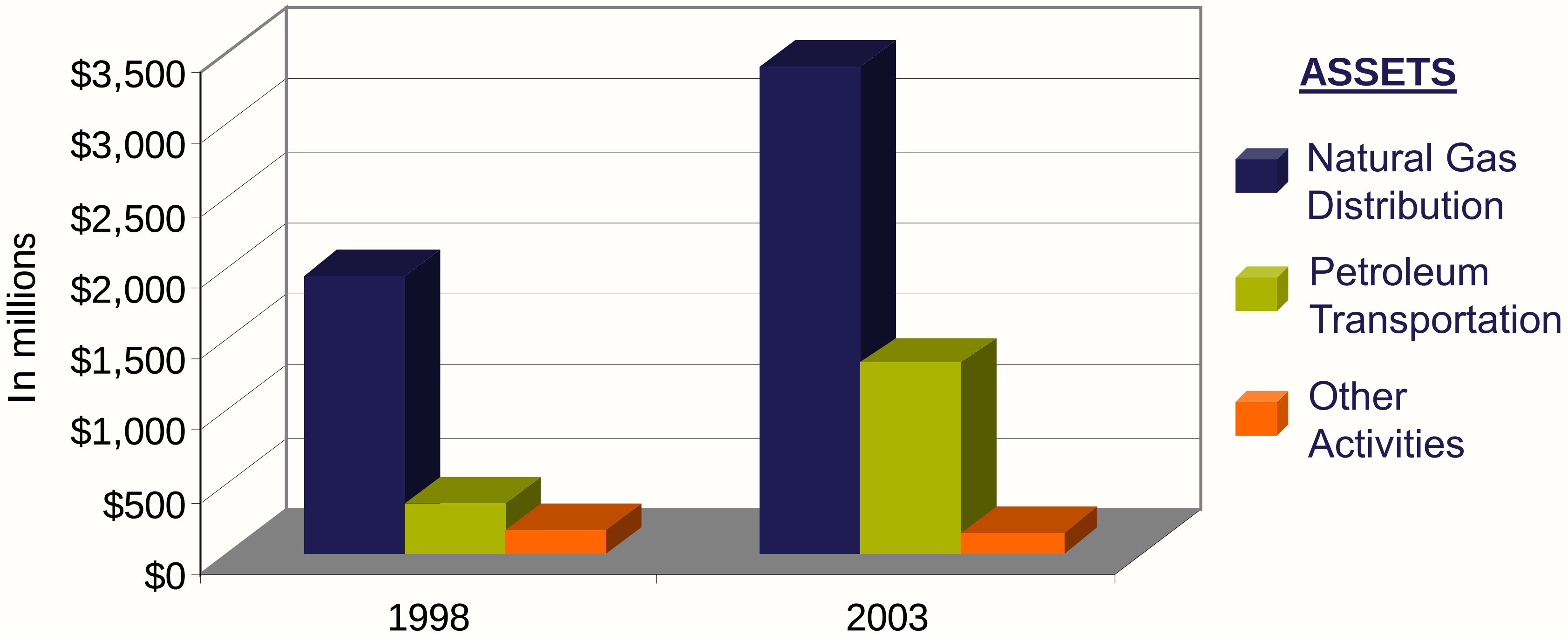
STRATEGY

Our Value Proposition

- **Focused** on our regulated businesses
- **Reliable** and consistent results from low risk businesses
- **Growing** and steadily outperforming through value creation

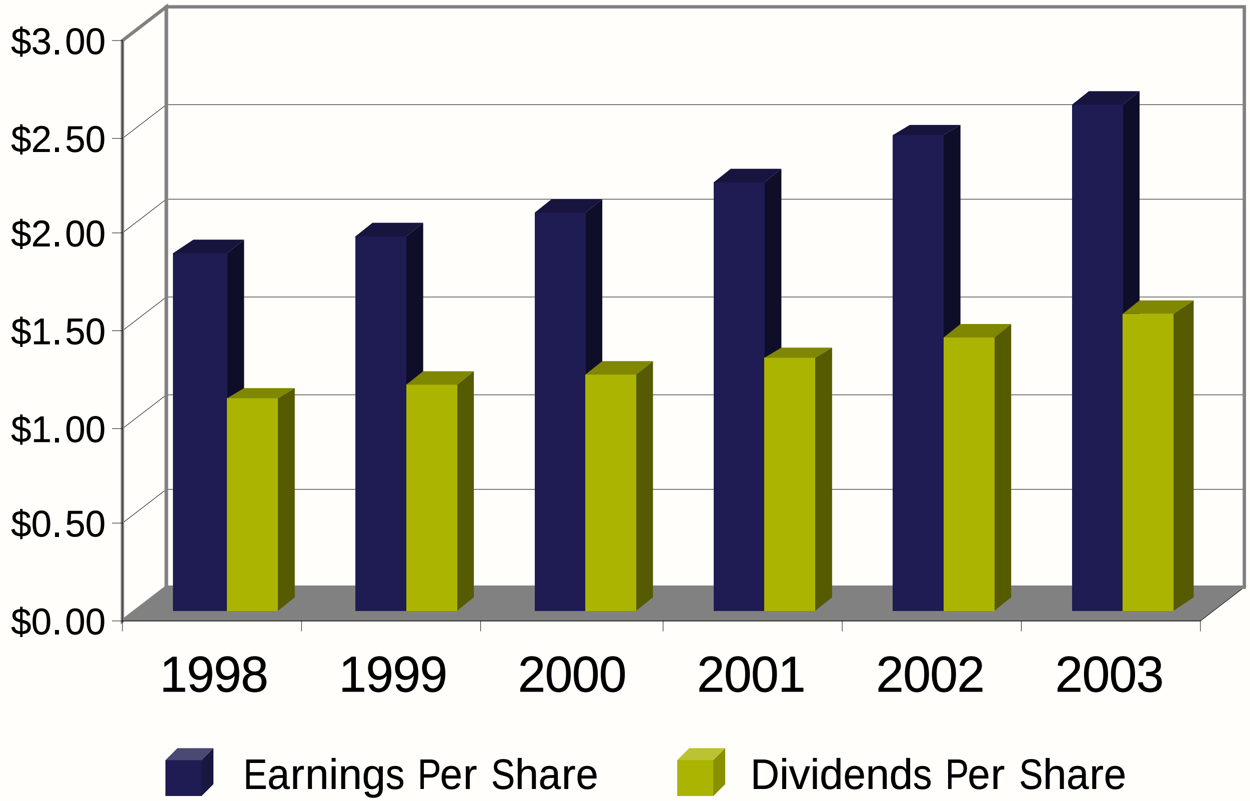
Focused

Growth has come from investments in core regulated businesses



Reliable

Consistent results from low risk businesses – target earnings growth of 6% and dividend payout of 60%



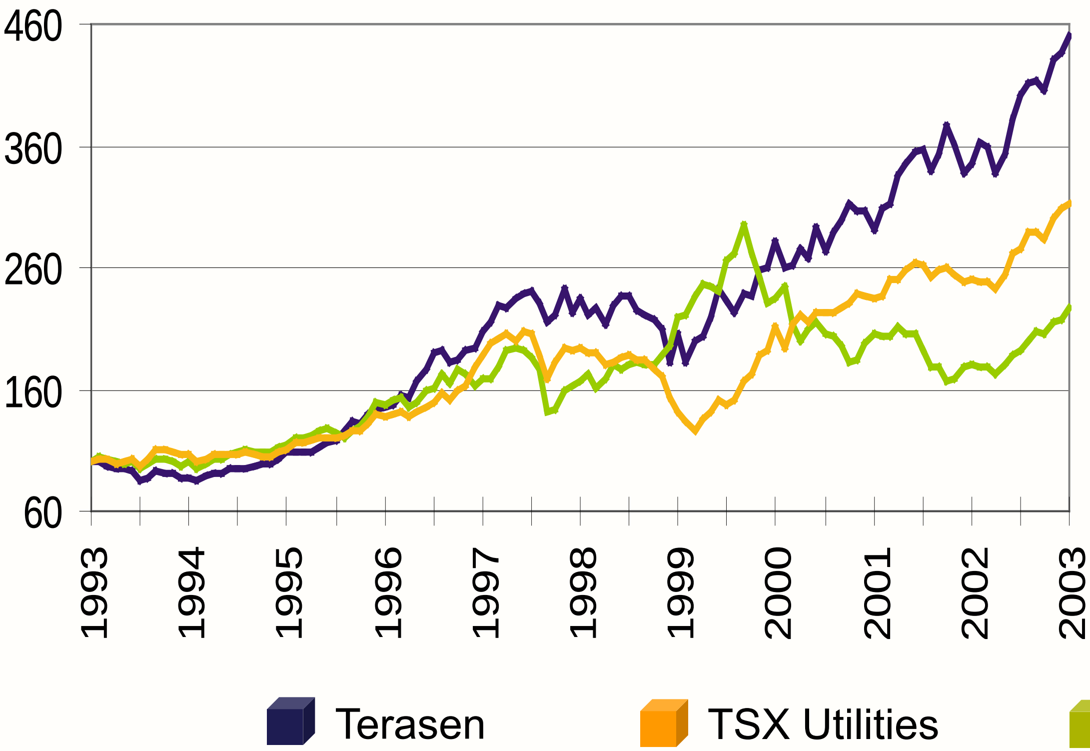
7.2% Annual EPS Growth

7.0% Annual DPS Growth

Growing

Consistent outperformance through value creation

Total Shareholder Returns



Annualized Total Returns

	One Year	Three Year	Five Year	Ten Year
Terasen	30%	17%	14%	16%
TSX Utilities Index	27%	14%	10%	12%
TSX Composite Index	27%	-1%	7%	9%

For the period ended December 2003

Asset and Risk Management

- 97% of assets are regulated
  - Major growth is in regulated activities
- Regulatory arrangements
  - No weather or customer usage risk
  - No cost of gas risk
- No international investments
- No non-regulated energy trading

Core Value Strategies

- **Operational excellence** within incentive regulation
- **Focused growth** based on value creation
- **Financial excellence** ensuring access to competitive sources of capital

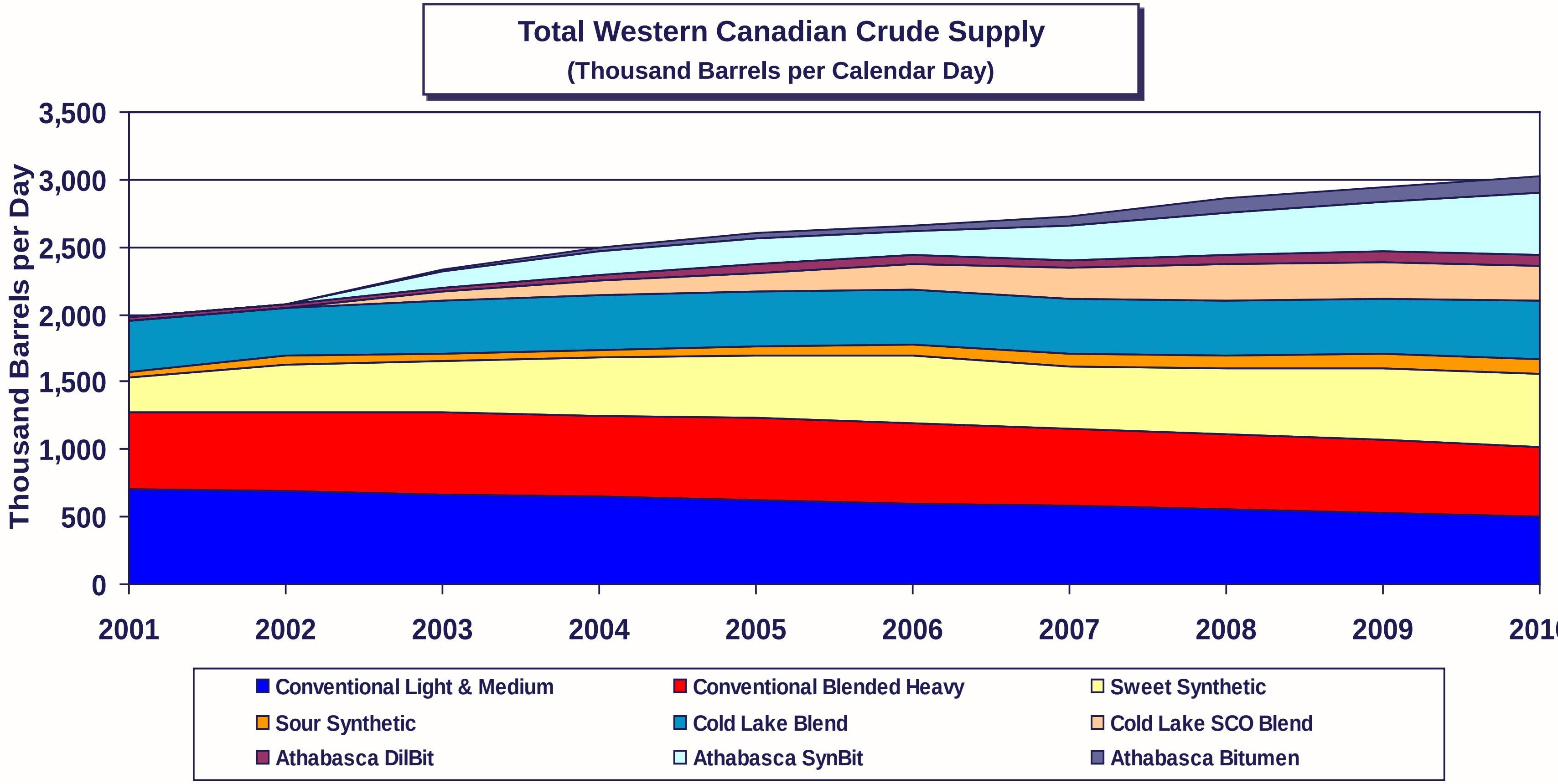
Terasen

Terasen Pipelines

Terasen Pipelines

Petroleum Pipelines   Alberta Oil Sands Deposits

Canadian Crude Supply Forecast

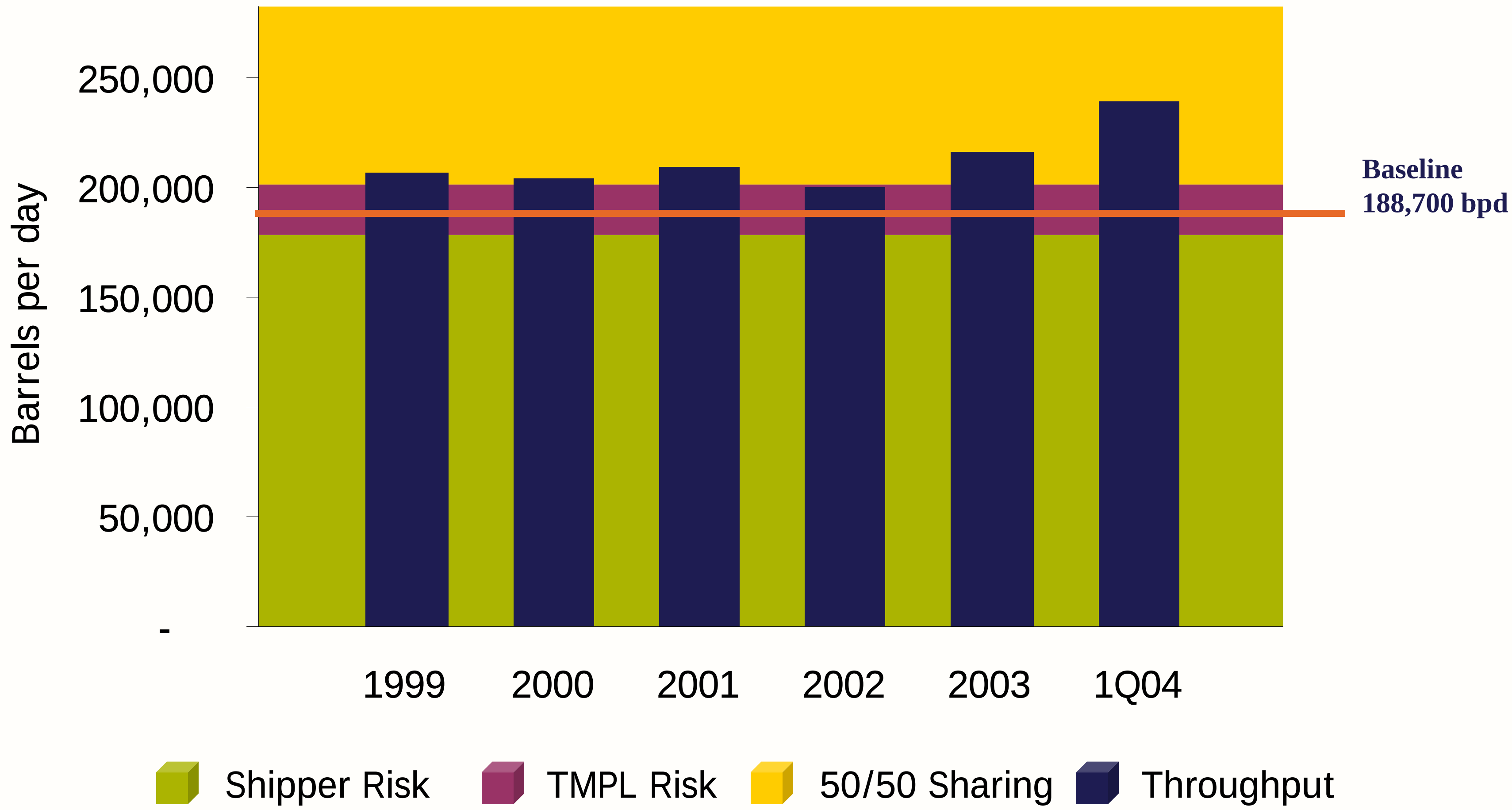


CAPP Upper Supply Case – Total Supply

Trans Mountain 2001 – 2005 Incentive Toll Settlement

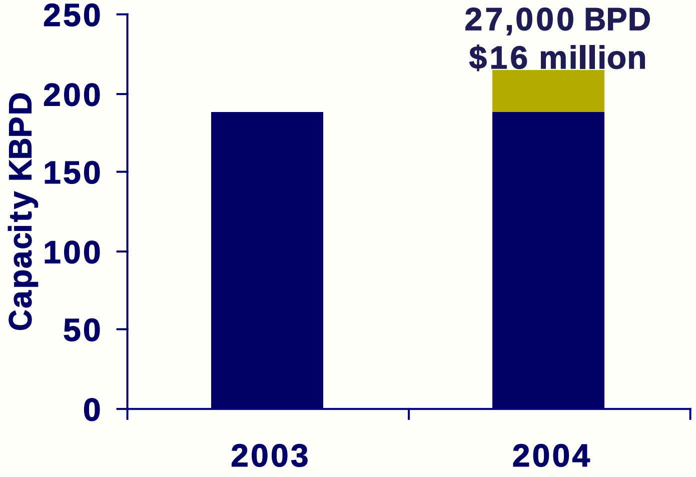
- Structured around Shipper’s desire for fixed tolls
- TMPL benefits from 100% of operating cost reductions
  - – No escalation of tolls for inflation
- TMPL assumes limited throughput risk
- Incentives for additional throughpu

Trans Mountain
Canadian Throughput and Volume Risk



Trans Mountain

- Oil sands production driving throughput growth
- Expansion can provide producers with greater access to California & Far East markets

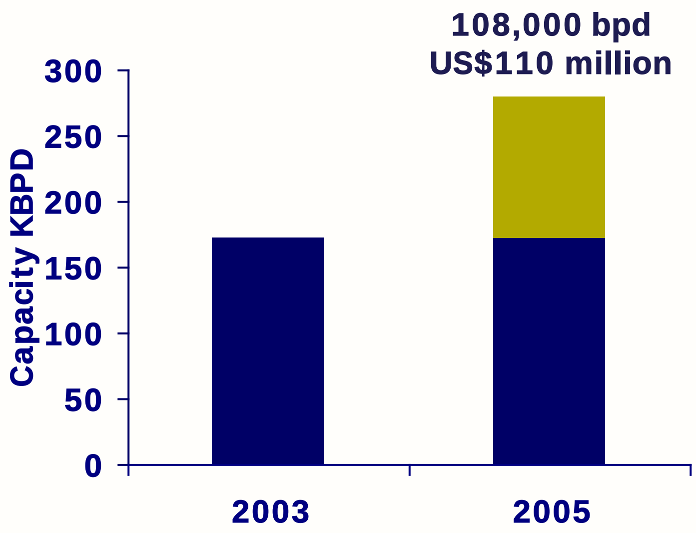


Express

- Acquired January 2003
- Express has been running at capacity, with 85% of total capacity of 172,000 bpd committed through long-term contracts
- Strong shipper response to recent open season
- Following the expansion 79% of the 280,000 total capacity will be committed through long-term contracts

Express

- Both phases of the expansion are expected to be completed by April 2005

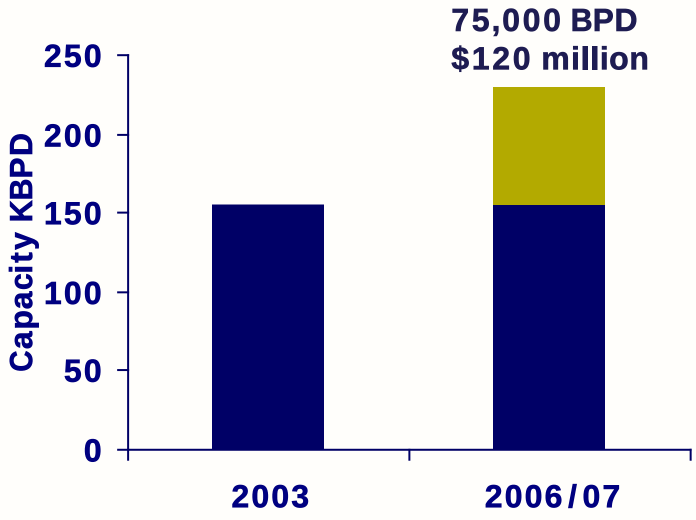


Corridor

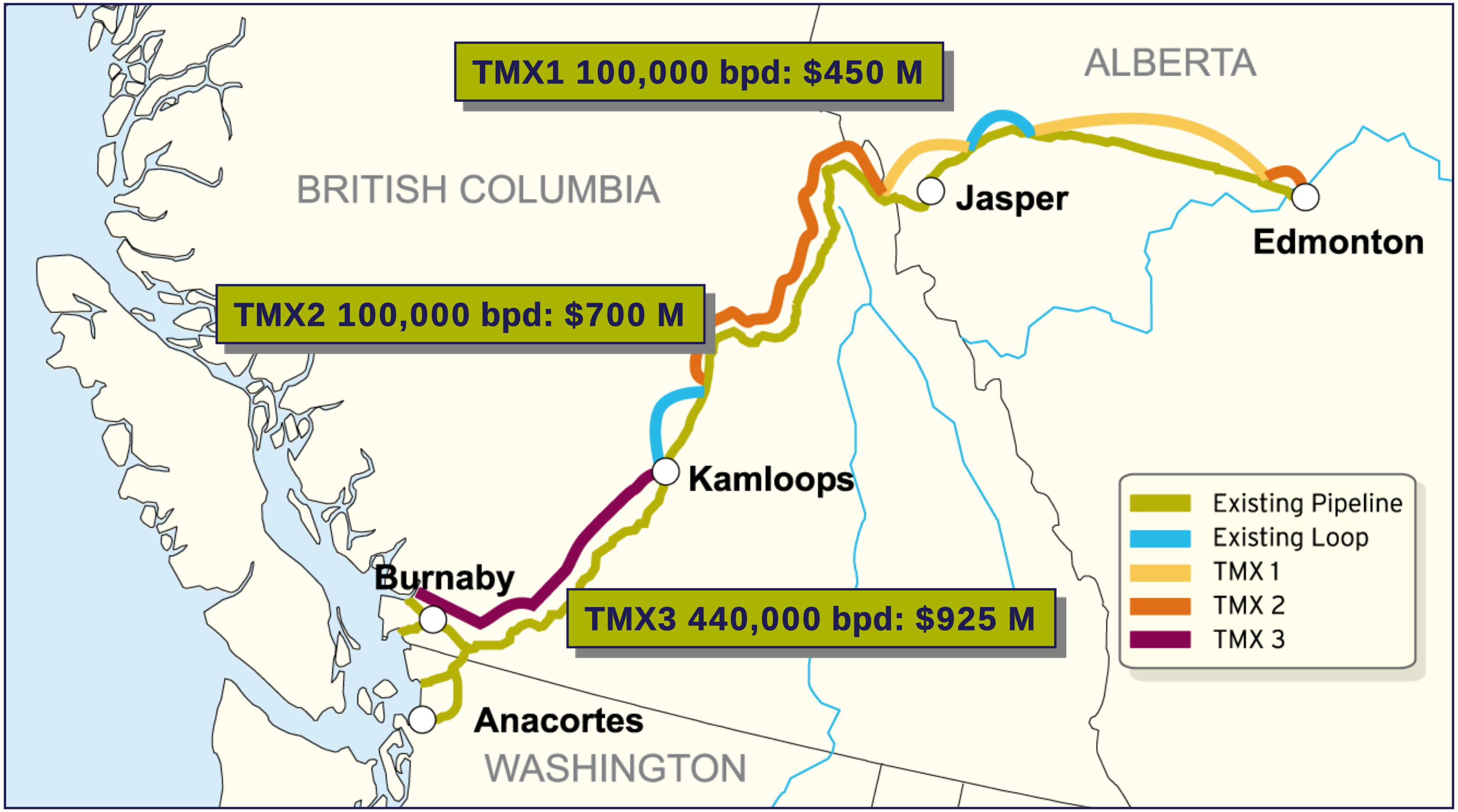
- Completed on time and on budget in May 2003
- Backed by 25 year ship-or-pay contract with Shell Canada (60%), Chevron (20%) and Western Oil Sands (20%)
- Provides for recovery of all operating costs, depreciation, taxes and financing costs in revenue requirement
- 25% equity component, ROE is long-term Canada's plus 350 bps

Corridor

- Expansion will be undertaken on similar terms as original agreement
- Timing dependent on mine expansion plans



TMX


TMX1 100,000 bpd: $450 M
ALBERTA
BRITISH COLUMBIA
Jasper
Edmonton
TMX2 100,000 bpd: $700 M
Kamloops
Burnaby
TMX3 440,000 bpd: $925 M
Anacortes
WASHINGTON
Existing Pipeline
Existing Loop
TMX 1
TMX 2
TMX 3

TMX Advantages

- Built in stages
  - Lower construction risk
  - Matches capacity with supply/demand growth
  - Lowers risk of overbuild
- Washington State refinery access
  - 550,000 bpd capacity
  - 10% current market share
- Existing rights-of-way
  - Options on private land

Terasen

Terasen Gas

2004-2007 PBR Settlement

- Capital structure – 33% common equity/67% debt
- Allowed ROE is determined annually using BCUC-established formula
  - ROE = Forecast Cda. Bond Yield + Risk Premium
  - Mechanism is similar to NEB Multi-Pipeline formula
  - ROE for Terasen Gas in 2004 was set at 9.15%, compared with 9.42% in 2003

2004-2007 PBR Settlement

- Performance-based regulatory settlement with incentives for operating efficiencies – benefits shared 50% with customers
- Performance-based regulatory arrangements have enabled Terasen Gas to exceed allowed ROE in every year since 1994

2004-2007 PBR Settlement

- O&M formula:
  – [Base Cost x (1+Growth) x (1+Inflation-Adjustment factor)]
  – Adjustment factors of 50% CPI in 2004 and 2005, and 66% CPI in 2006 and 2007

- New deferral accounts established for insurance and pension costs

2004-2007 PBR Settlement

- Gross margin protected by two deferral accounts:
  - Gas Cost Reconciliation Account (GCRA)
  - Revenue Stabilization Adjustment Mechanism (RSAM)

- RSAM defers any variances in use per customer among residential and commercial customers
  - Eliminates exposure to weather variations
  - Also eliminates exposure to reductions in use per customer caused by other factors (e.g. higher prices)

2004-2007 PBR Settlement

- RSAM does not cover margin from industrial customers
  - Less sensitive to weather fluctuations
  - Industrial margin is reset annually
  - Regulatory relief can be sought if industrial margins fall significantly below forecast
- Industrial and large commercial customers can select commodity+transportation or transportation service only
  - Terasen earns approximately the same margin in either case

Terasen

2004-2007 PBR Settlement

- Variances between actual and forecast gas costs are deferred and recovered through GRCA
- During 2003, RSAM and GCRA balances were recovered in rates, thereby reducing the recovery balances
  - Combined GCRA/RSAM balance $34.8 million at end of 2003, compared with $76.7 million at the end of 2002

2004-2007 PBR Settlement

- BCUC has approved a mechanism for quarterly adjustment of rates
  - If projected recovery of:
    a) actual gas costs, and
    b) amortization of prior GCRA balances,
    falls outside of 95-105% deadband, rates are adjusted, subject to BCUC approval
- Lower natural gas costs resulted in the BCUC approving a decrease in customer rates in December 2003 (7.5% decrease for the average residential customer)

2004-2007 PBR Settlement

- Gas Supply Incentive Program
  - Provides an incentive to mitigate fixed costs of gas supply & transportation by selling excess gas and transportation capacity to off-system customers
  - Has generated shareholder revenues of $1-2 million per year over the last several years
- Unbundling
  - Terasen Gas, BCUC & customer representatives have all been supportive of unbundling
  - Unbundling for commercial customers expected in late 2004
  - No financial impact on Terasen anticipated

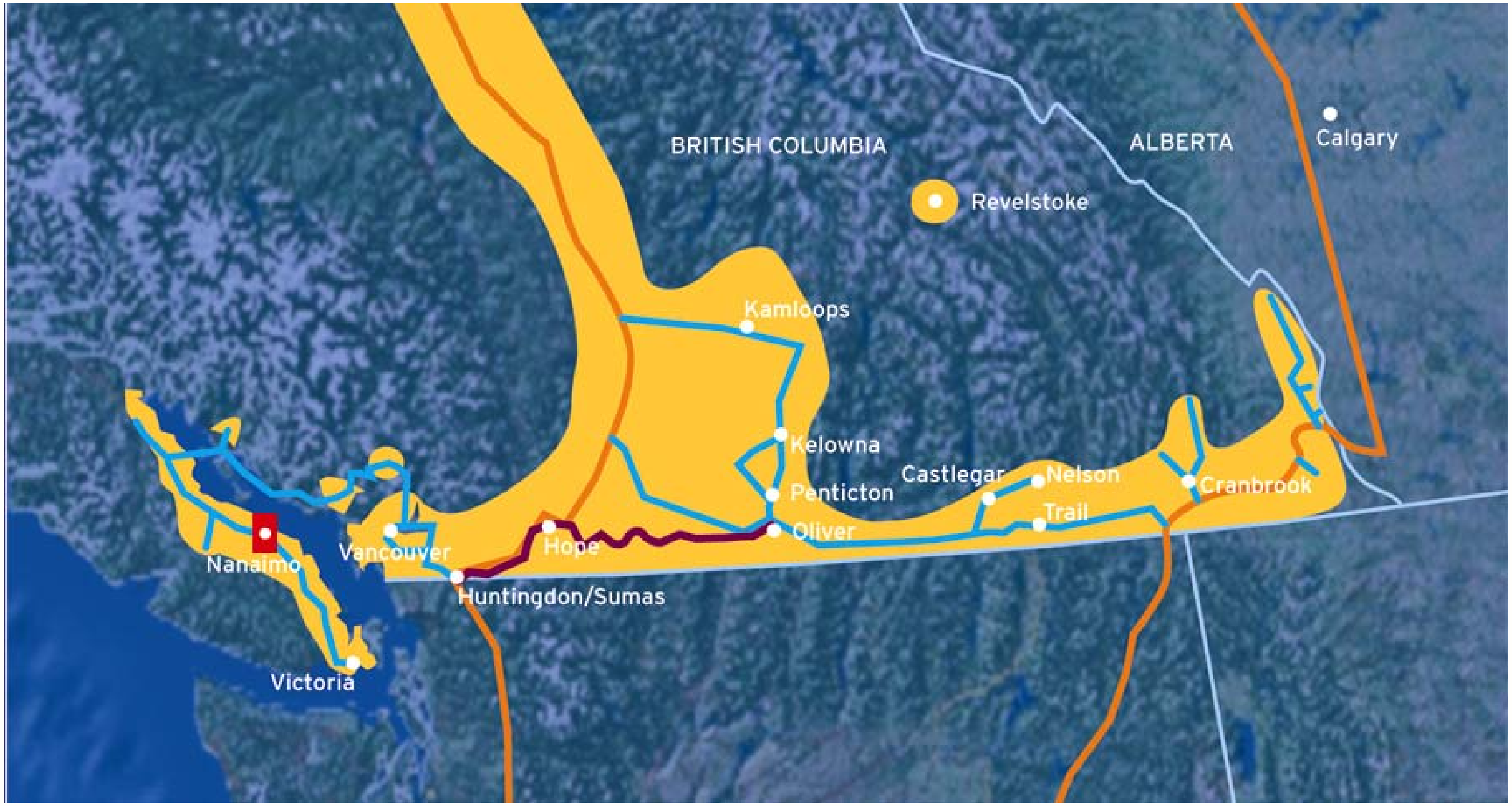
TGVI – 2003-2005 Regulatory Settlement

- Took effect January 1, 2003
- Capital structure – 35% common equity/65% debt
- Allowed rate of ROE that is 0.50% higher than Terasen Gas – 9.65% for 2004, compared with 9.92% in 2003
- Continuation of operating and maintenance cost incentive mechanisms
- Deferral accounts protect against cost of gas, weather risk, etc. – similar to Terasen Gas, but more comprehensive

TGVI – RDDA

- Revenue deficiency deferral account (RDDA) arose from low customer rates charged prior to December 31, 2002
  - Deferral account balances funded by preferred shares issued to parent
  - BCUC directed to set rates to recover RDDA over the shortest period possible, while remaining competitive with alternative energy sources
  - Customer rates set using conventional methods beginning January 1, 2003

New Infrastructure Projects



Terasen Transmission Lines

Terasen Distribution Service Area

Other Natural Gas Lines

Proposed Inland Pacific Connector Pipeline

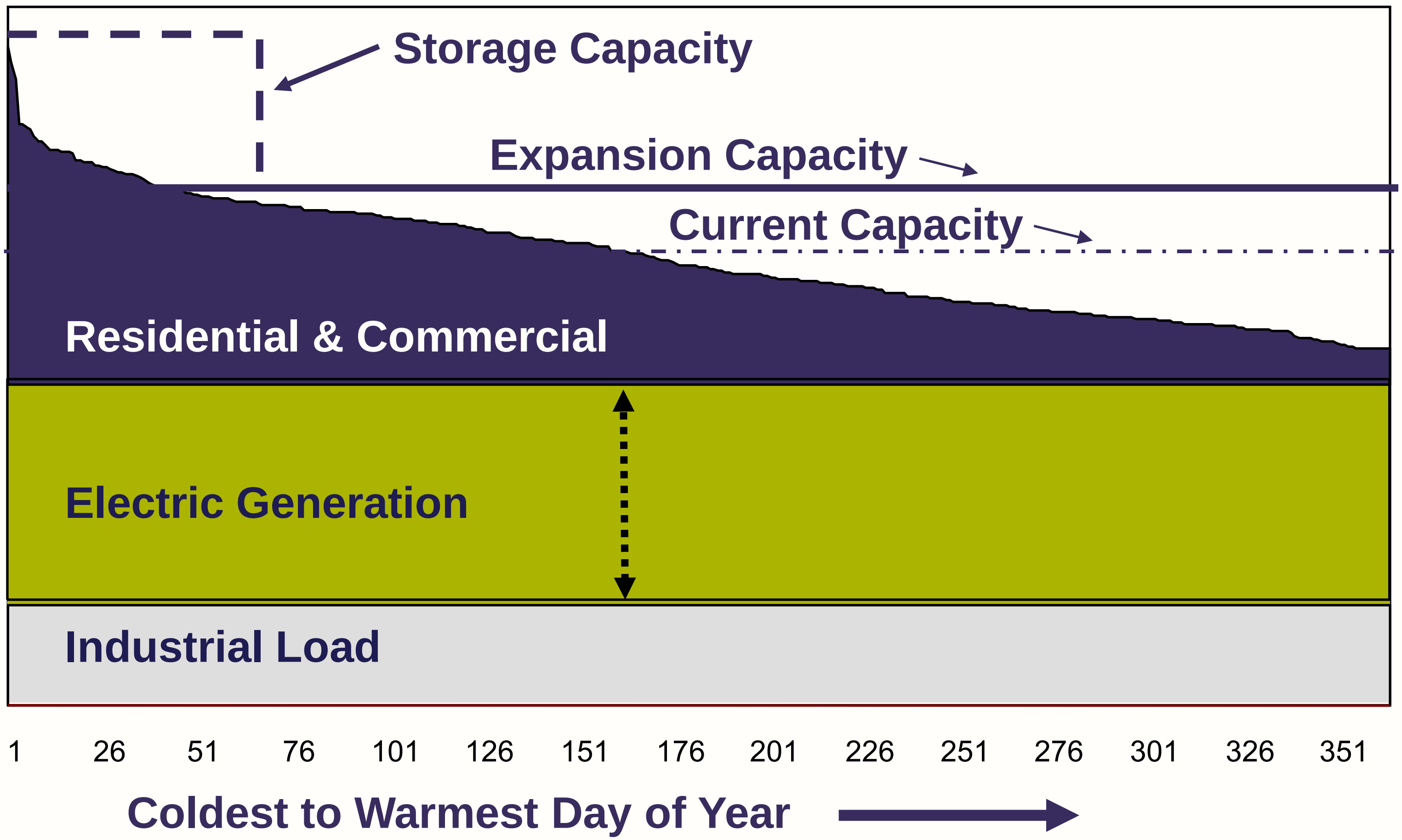
Proposed LNG Storage Tank

New Infrastructure Projects

Capacity expansion to Vancouver Island

- New on-Island power generation needed
- $180 million capacity expansion proposed
  - Additional compression and a new LNG tank

New Infrastructure Projects



New Infrastructure Projects

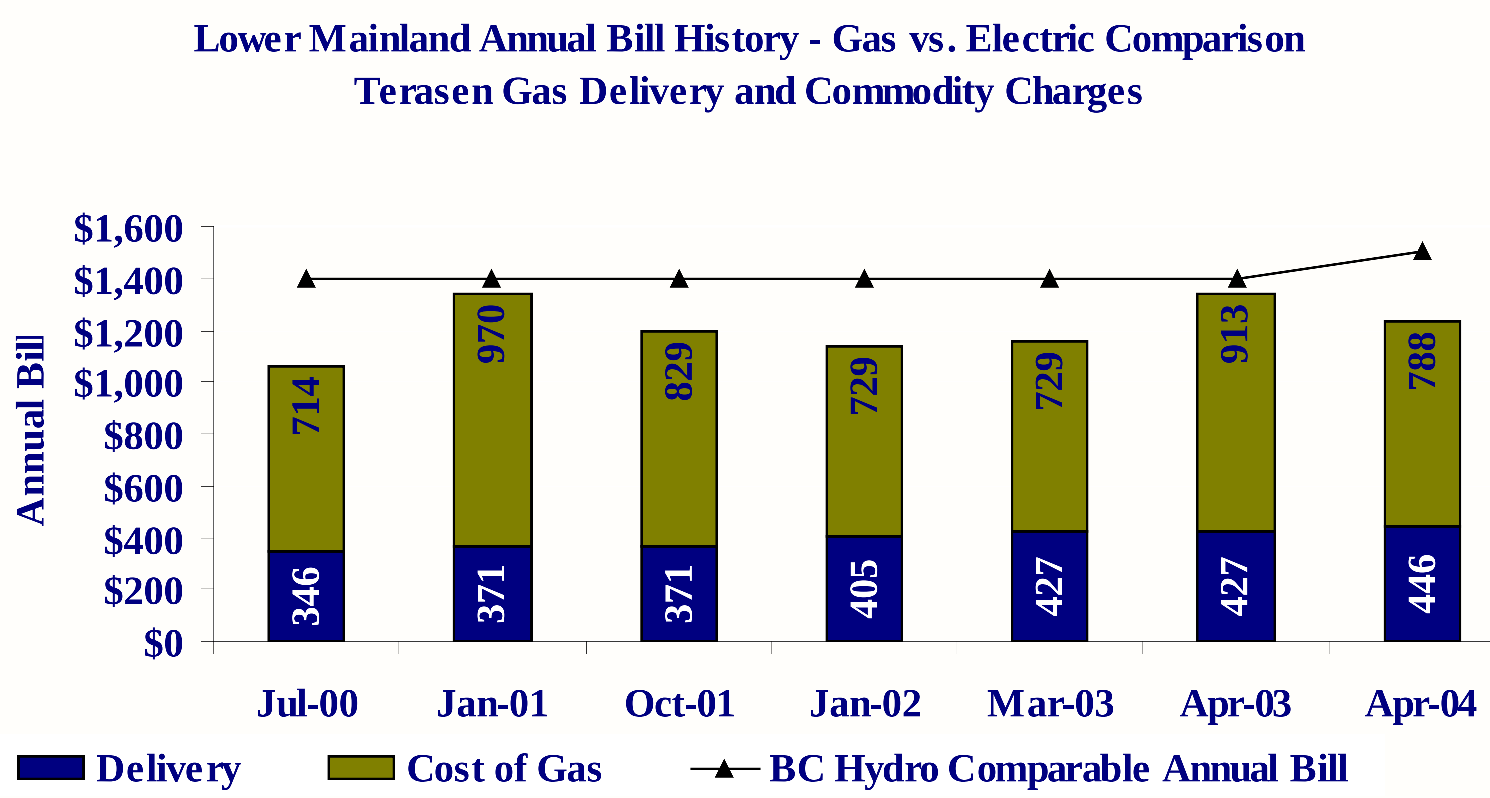
Inland Pacific Connector

- New pipeline to extend Southern Crossing pipeline to Sumas/Huntingdon
- Positioned to meet demand for natural gas capacity expansion in Pacific Northwest

Price Competitiveness

- In B.C., natural gas has historically enjoyed a significant cost advantage vs. alternative fuels, including electricity
- Increases in the market price of natural gas, combined with a government-mandated electricity price freeze, eroded this advantage
- Terasen Gas maintains an active price risk management program (on behalf of customers) which mitigates this risk
- Recent rate reductions have partially restored natural gas' price advantage

Price Competitiveness



Terasen Utility Services

Terasen Waterworks

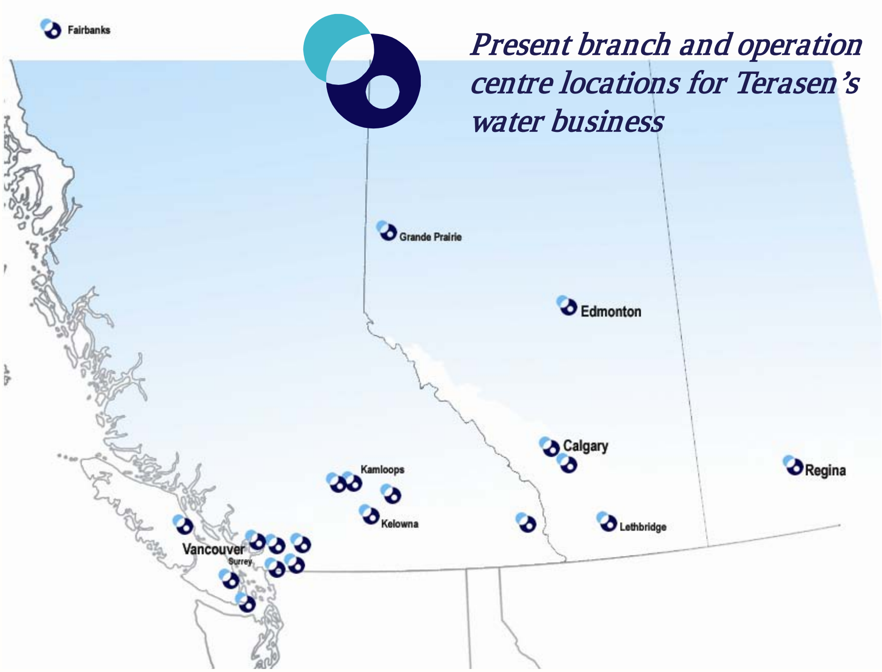
Water and Utility Services

- Continues to be a relatively small part, but growing, of our asset base and operating income
- Looking for opportunities to capitalize on economies of scope and scale, in terms of the services that are provided and regions that are covered

Water and Utility Services

- Largest private water services company in Western Canada

- Focus on annuity operating contracts and selective investment opportunities



Fairbanks Acquisition

- April 2004 – acquired a 50% interest in Fairbanks Sewer & Water (FSW) for approximately US$30 million
- FSW provides water and wastewater treatment and water distribution services to the 82,000 residents of Fairbanks, Alaska
- FSW will provide a model for other opportunities in Western North America
- Option to purchase remaining 50% in 2009 at fair market value
- The transaction is subject to regulatory approvals, and is expected to be finalized in the summer of 2004

Appendix: Municipal Leasing Transactions

Municipal Leasing Transactions

- Certain municipalities have franchise agreements which permit the municipality to purchase the distribution assets at "fair value"
  - No munis in Vancouver area have this option
  - Most munis elsewhere have given up the option through agreement renewals
- Munis can finance Terasen Gas assets with 100% MFA debt, and does not pay tax.
- Leasing arrangements negotiated to provide Munis with financial benefits and risks of ownership, while allowing Terasen Gas to operate.

Municipal Leasing Transactions

- Terasen Gas assets are leased to Kelowna for $50 million prepaid rent under a long-term capital lease
- Terasen Gas enters into an operating lease to operate the assets
  - Kelowna is paid the revenue requirement associated with $50 million of utility capital
    - return on equity
    - cost of debt
    - income taxes
    - depreciation
- Changes in revenue requirement (e.g. ROE) are flowed through to Kelowna

Municipal Leasing Transactions

- No change for regulatory purposes
  - Lease simply flows through certain components of revenue requirement to Munis
  - No impact on customers
- Terasen Gas retains option to terminate agreements at the end of 17 years and retain ownership benefits
  - Termination payment = depreciated book value

Municipal Leasing Transactions

- Terasen Gas transfers risk and reward associated with assets and retains the option to control the assets after year 17
- Closed Nelson lease agreement on March 2, 2004 – value $8 million
- Terasen Gas has entered into leasing transactions with a total value of $83 million
- Total potential value (including current leases) of $200 million

Presentation to Moody's Investors Service

May 2005

Terasen

Presentation Overview

- Corporate Overview
- Terasen Gas
- Terasen Pipelines
- Terasen Water and Utility Services

Corporate Structure

- Terasen Inc.
  - Natural Gas Distribution
    - Terasen Gas
    - Terasen Gas (Vancouver Island)
    - Other
  - Petroleum Transportation
    - Trans Mountain Pipeline
    - Corridor Pipeline
    - Express/Platte Pipelines (33%)
    - Other
  - Water & Utility Services
    - Terasen Waterworks
    - Terasen Utility Services
    - Fairbanks Sewer & Water (50%)
    - Customerworks (30%)
  - Other Activities
    - Terasen International
    - Clean Energy (45%)
    - Corporate

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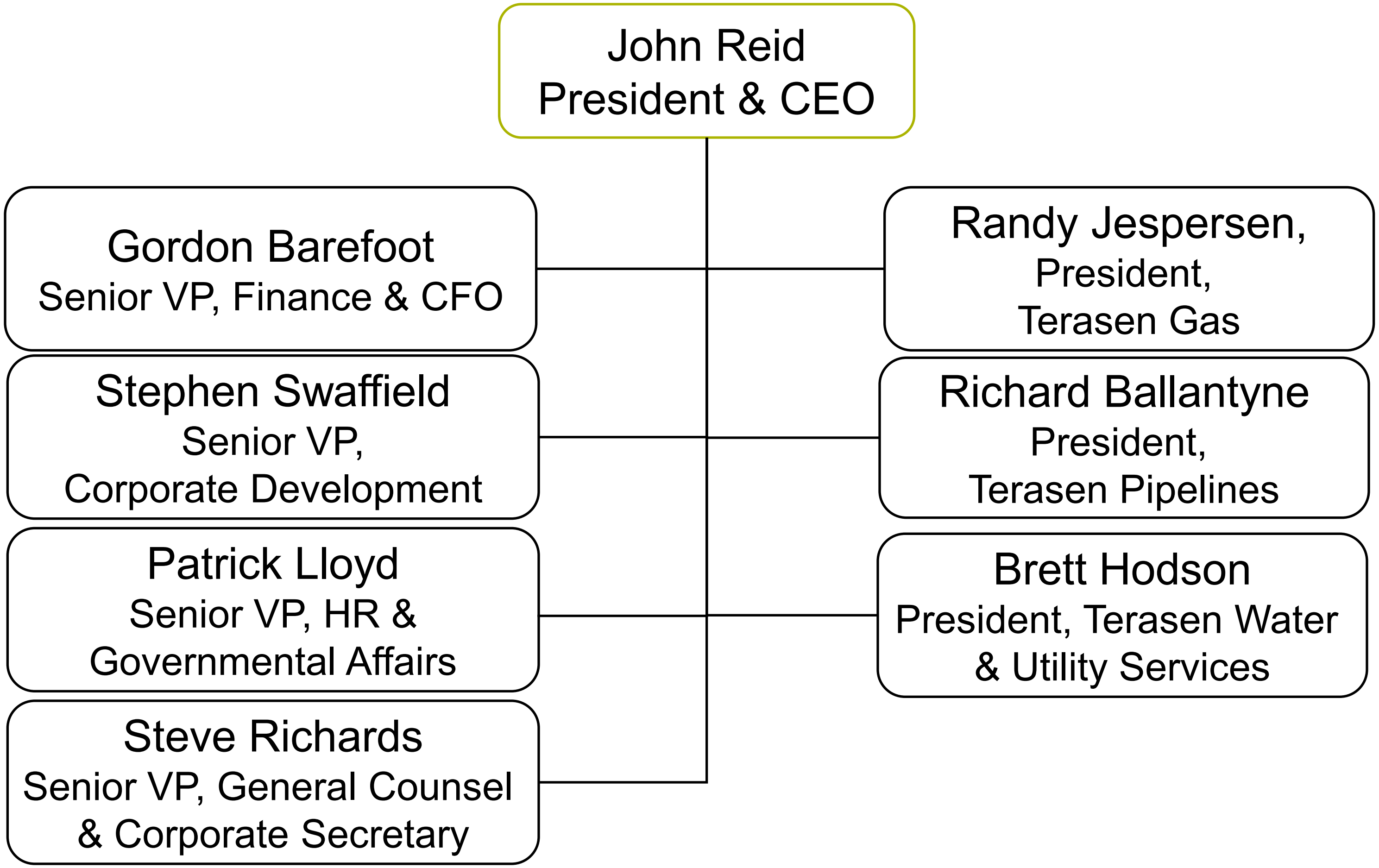
Management


John Reid
President & CEO
Gordon Barefoot
Senior VP, Finance & CFO
Stephen Swaffield
Senior VP,
Corporate Development
Patrick Lloyd
Senior VP, HR &
Governmental Affairs
Steve Richards
Senior VP, General Counsel
& Corporate Secretary
Randy Jespersen,
President,
Terasen Gas
Richard Ballantyne
President,
Terasen Pipelines
Brett Hodson
President, Terasen Water
& Utility Services

Area of Operations

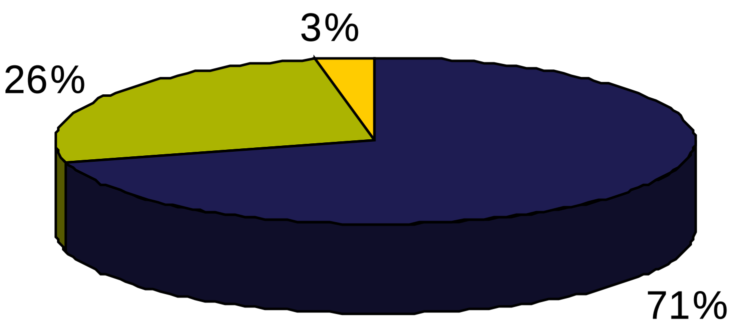
Petroleum Transportation

Natural Gas Distribution

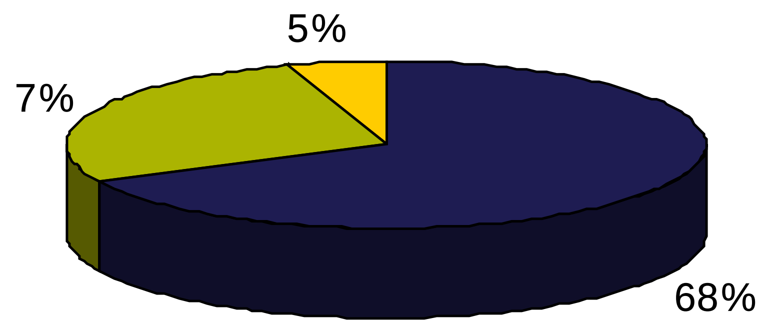
Terasen

Corporate Overview

Operating Income: $377 million
(12 months ended December 31, 2004)



Assets: $4,971 million
(at December 31, 2004)



Natural Gas Distribution **Petroleum Transportation** **Other Activities**

Terasen

2004 Highlights

- Natural Gas Distribution – achieved operating efficiencies between TGVI and Terasen Gas, which were shared with customers
- Trans Mountain Expansion – completed the 27,000 barrel per day upgrade of the Trans Mountain pipeline
- Express Expansion – commenced construction on the expansion, which is now in-service and providing additional capacity of 108,000 bpd

terasen

2004 Highlights

- Fairbanks Acquisition – acquired a 50% interest in Fairbanks Sewer and Water Inc.
- Earnings Growth – Continuing earnings in 2004 were $1.40 per share, up 6.9% over EPS (before non-recurring items) of $1.31 in 2003
- Financial Strength – EBIT Interest Coverage increased from 2.1x in 2003 to 2.4x in 2004, and Common Equity/Total Capital increased from 30.0% to 31.7%

Terasen

Terasen Gas

Terasen Gas/TGVI Integration

- Management and operational integration of TGI and TGVI is substantially complete
  - Single management team, common processes, common systems
- Earnings contribution from operational efficiencies was $4.1 million in 2004
  - Reinforces Terasen Gas' best-in-class position on operating efficiency

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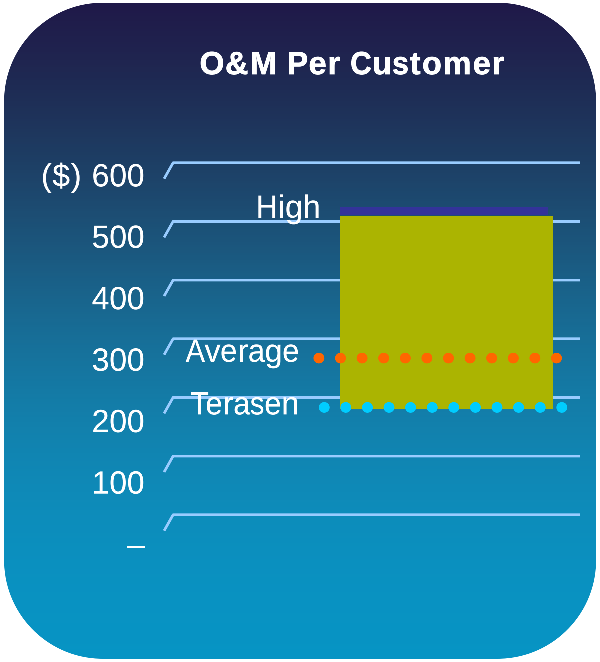
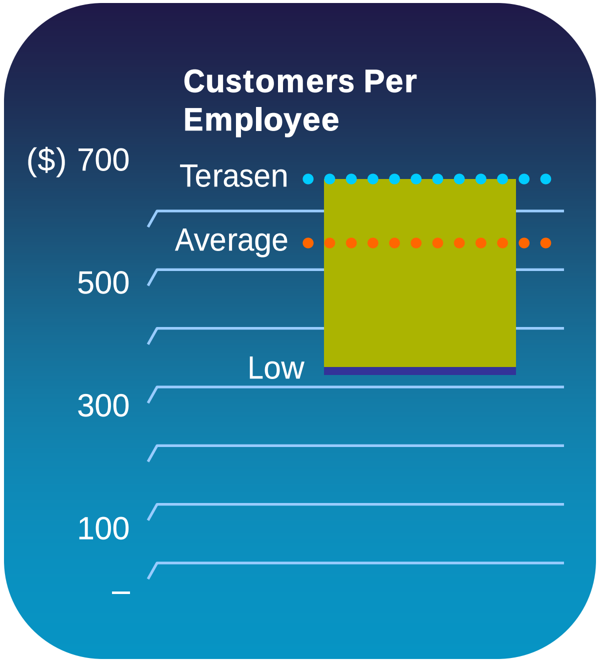
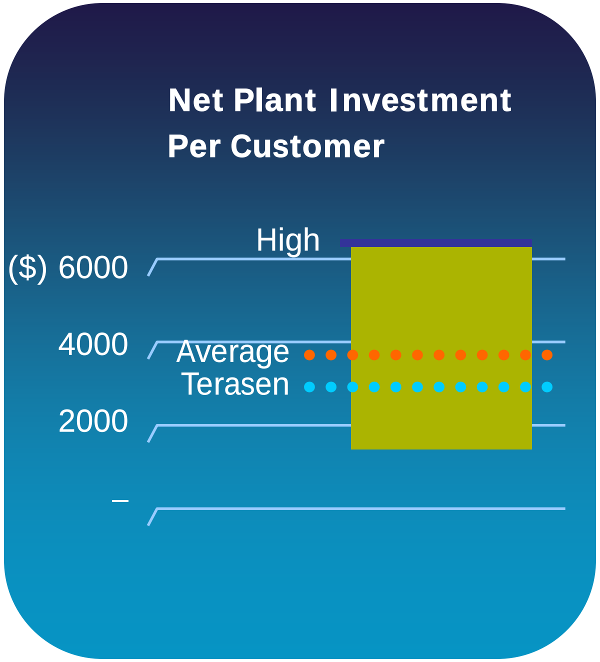
Operating Efficiency





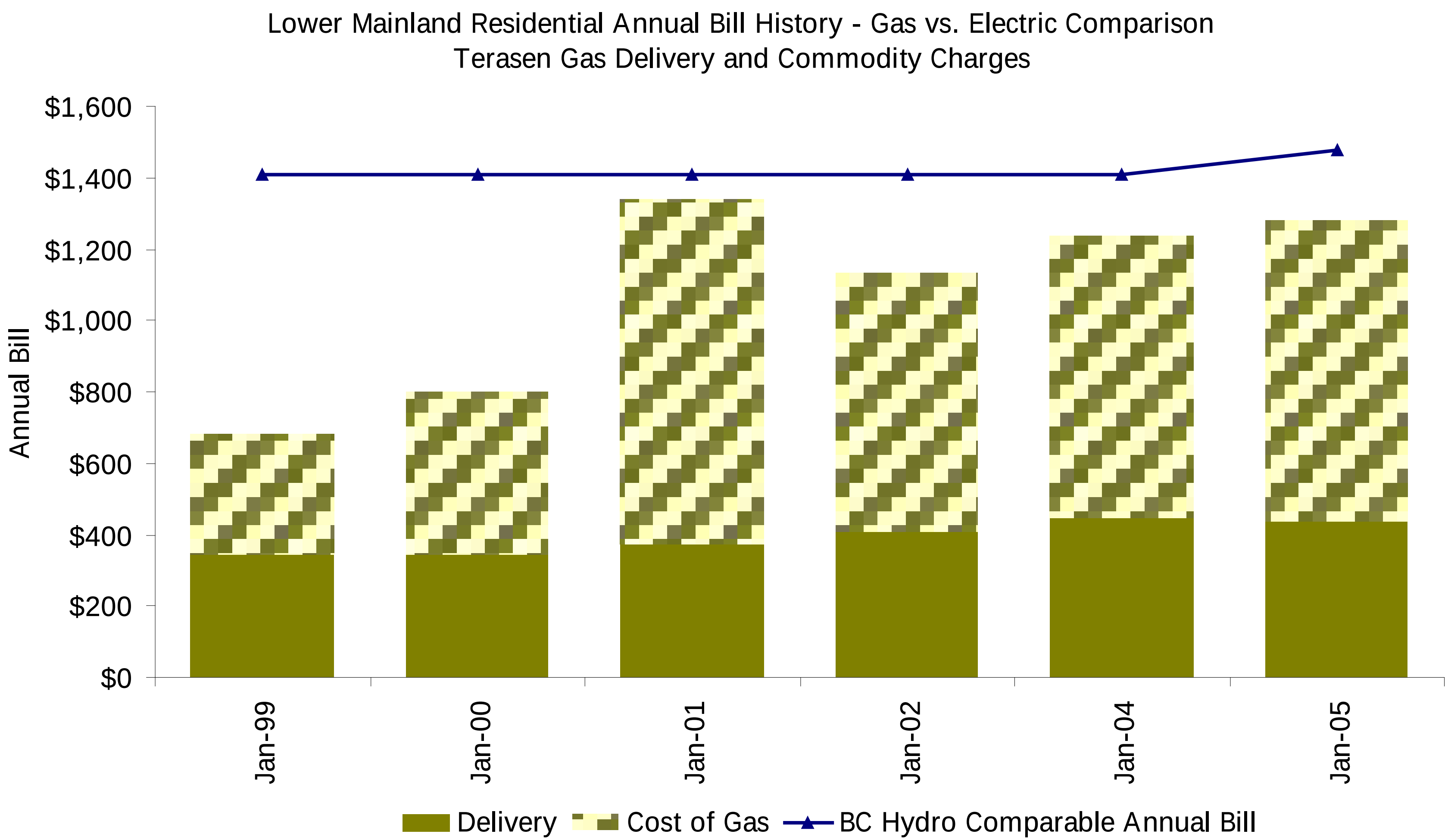


Source: LSM Consulting

Price Competitiveness

- Increases in the market price of natural gas, combined with a government-mandated electricity price freeze, have eroded the historical advantage over electricity
- Terasen Gas maintains an active price risk management program (on behalf of customers) which mitigates this risk
- BC Hydro has been supportive of demand-side management initiatives to encourage efficient energy use decisions

Price Competitiveness



Regulatory Arrangements

- 2004-2007 PBR in place for Terasen Gas
  - O&M and capital cost incentives, 50/50 sharing
  - Numerous deferral accounts
- 2003-2005 PBR in place for TGVI
  - O&M incentives, no sharing
  - Comprehensive deferral arrangements through Revenue Deficiency Deferral Account
  - Preference is to obtain a two-year extension to align regulatory calendar with Terasen Gas

Regulatory Arrangements

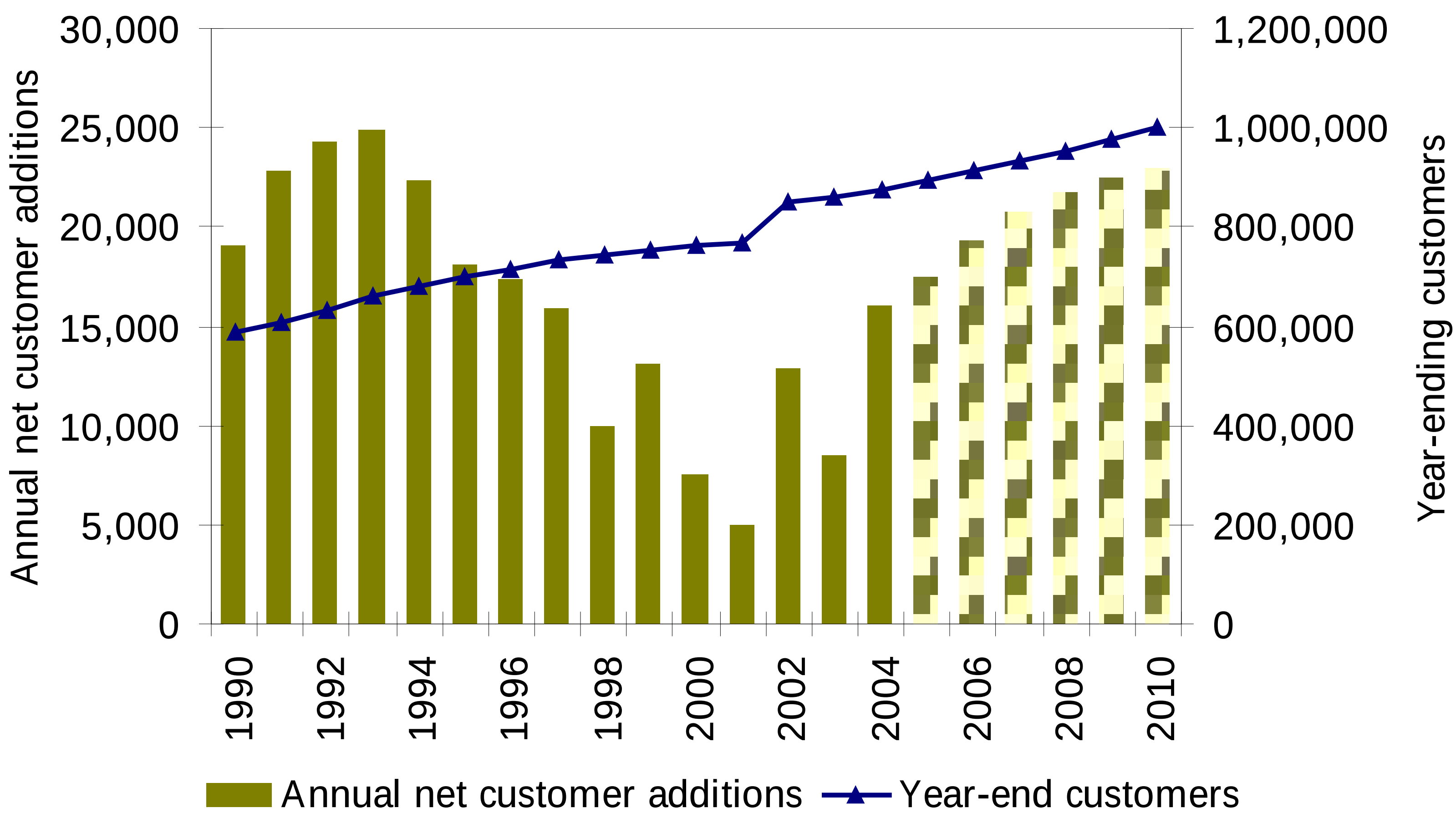
- ROE and Capital Structure hearing planned for Q3 2005
  - Allowed returns and equity components in B.C. are exceptionally low compared to other Canadian jurisdictions
    - April 2005 consensus forecast (if unchanged in November) would result in ROEs of 8.58% for Terasen Gas and 9.08% for TGVI in 2006
  - Since the last review in B.C. in 1999, gas/electric price competitiveness has narrowed significantly
- Good opportunity to present a case for higher ROE and/or equity components

Terasen

Terasen Gas - Outlook

- Successful efforts to improve operating efficiency in the past has limited the scope for future efficiencies
- Focus will be on increasing customer capture rates
  - Target of 1 million gas customers in 2010 (up from 878,000 currently)
  - Opportunity to improve capture rates for multi-family housing starts
  - Regional economy remains very strong
- Additional target of $1 billion in new investment by 2010

Customer Growth



*Data prior to 2002 excludes TGVI

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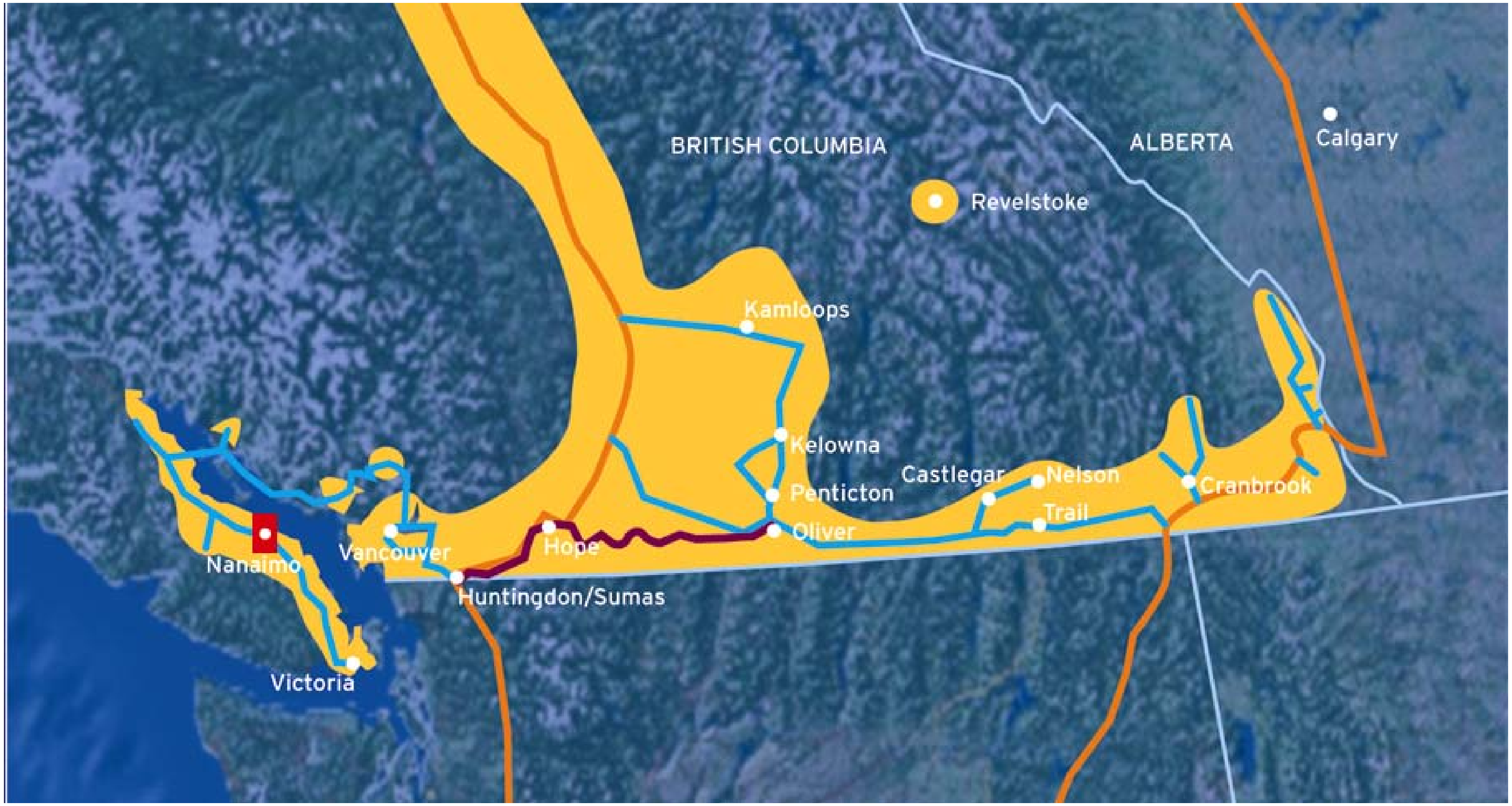
New Infrastructure Projects



Terasen Transmission Lines

Terasen Distribution Service Area

Other Natural Gas Lines

Proposed Inland Pacific Connector Pipeline

Proposed LNG Storage Tank

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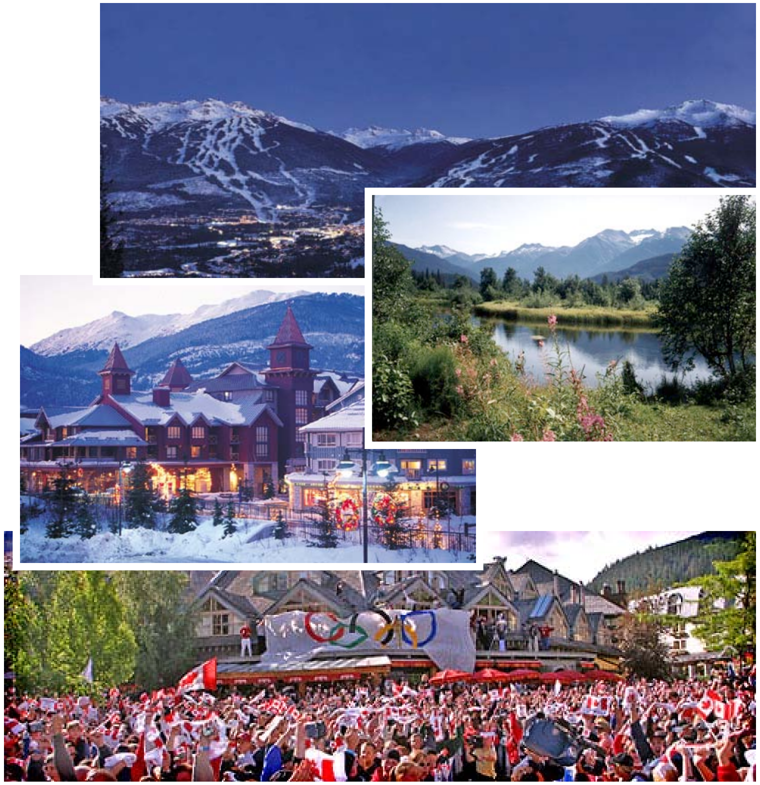
TGVI Expansion

- BCUC approved $100 mln Vancouver Island LNG Project subject to Duke Point power plant proceeding
- New LNG facility plus $50 mln compression expansion will be supported by long-term, take-or-pay contracts with BC Hydro for capacity on TGVI
- BCUC approval of Duke Point currently subject to appeal
  – Resolution expected in June
  – Initial request for leave to appeal was rejected

Growth – Whistler

- Working with the Resort Municipality of Whistler to develop a Sustainable Energy Strategy
  - Establish a hybrid gas/GSHP energy utility
  - Construct a natural gas pipeline from Squamish to Whistler
  - Develop renewable district energy systems or other sustainable options
- Estimated pipeline cost – $35 million
- Model for integrating natural gas with renewable energy sources



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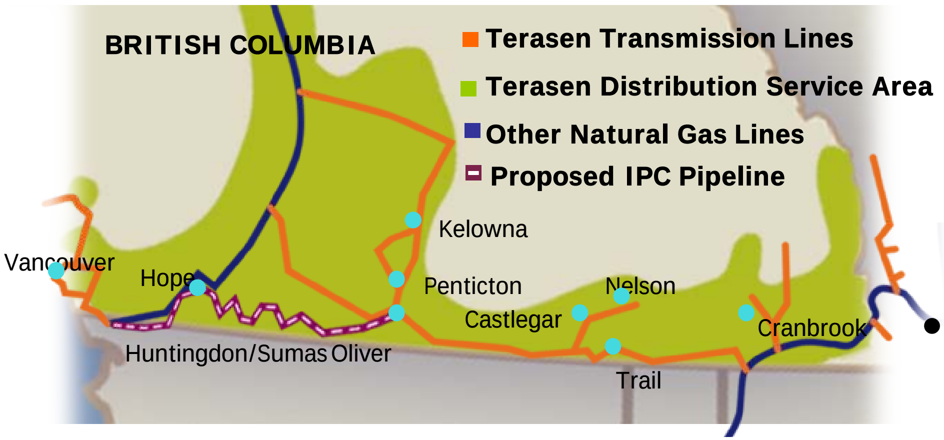
Inland Pacific Connector



- Potential $300 to $500 mln gas transmission line connecting SCP to the Lower Mainland & Sumas (NWPL)
- Project will require support from multiple shippers to move forward
- Increasing tolls on Duke System improving competitiveness

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Terasen
Pipelines

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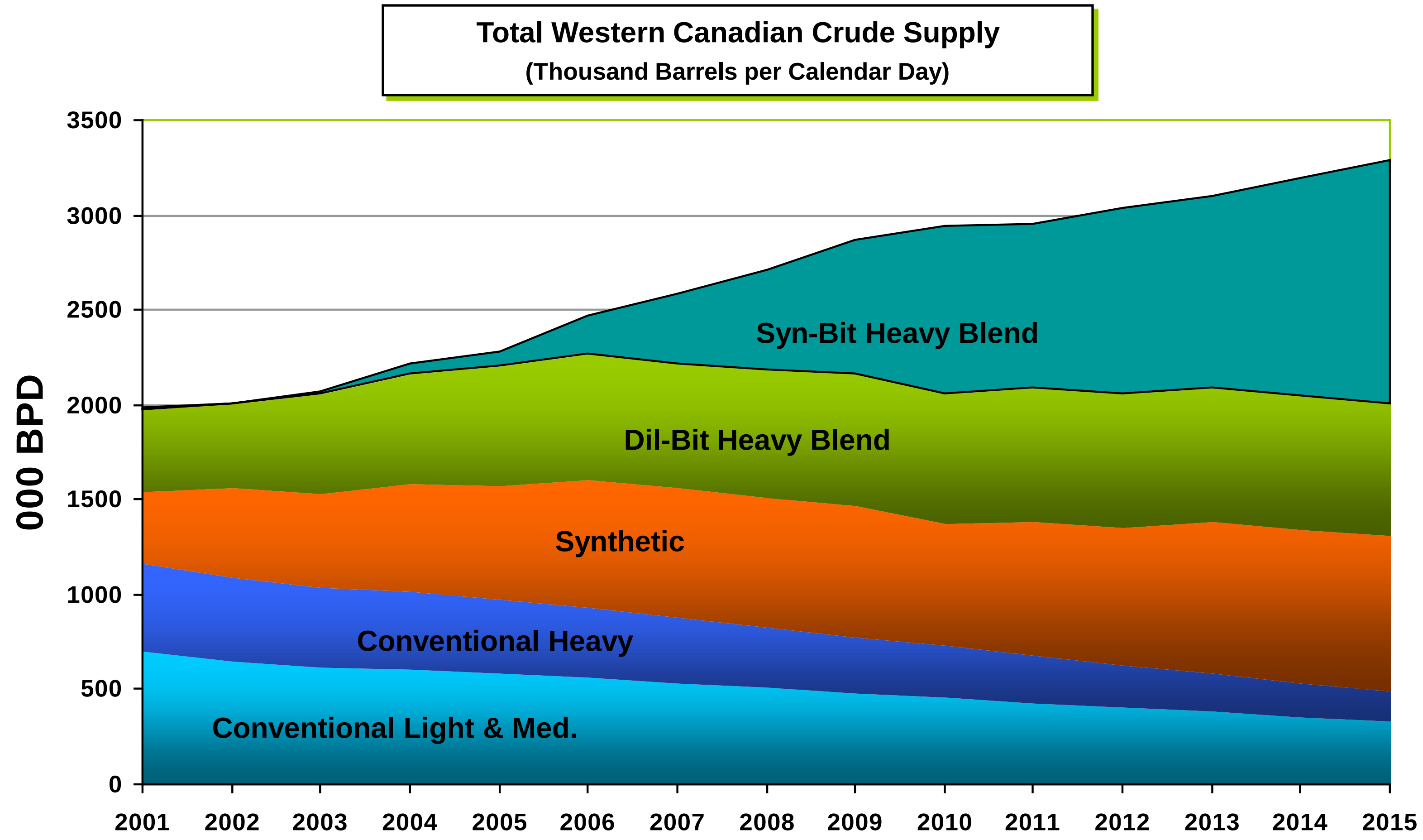
Terasen Pipelines

Petroleum Pipelines　Alberta Oil Sands Deposits

Canadian Crude Supply Forecast



CAPP Upper Supply Case – Total Supply

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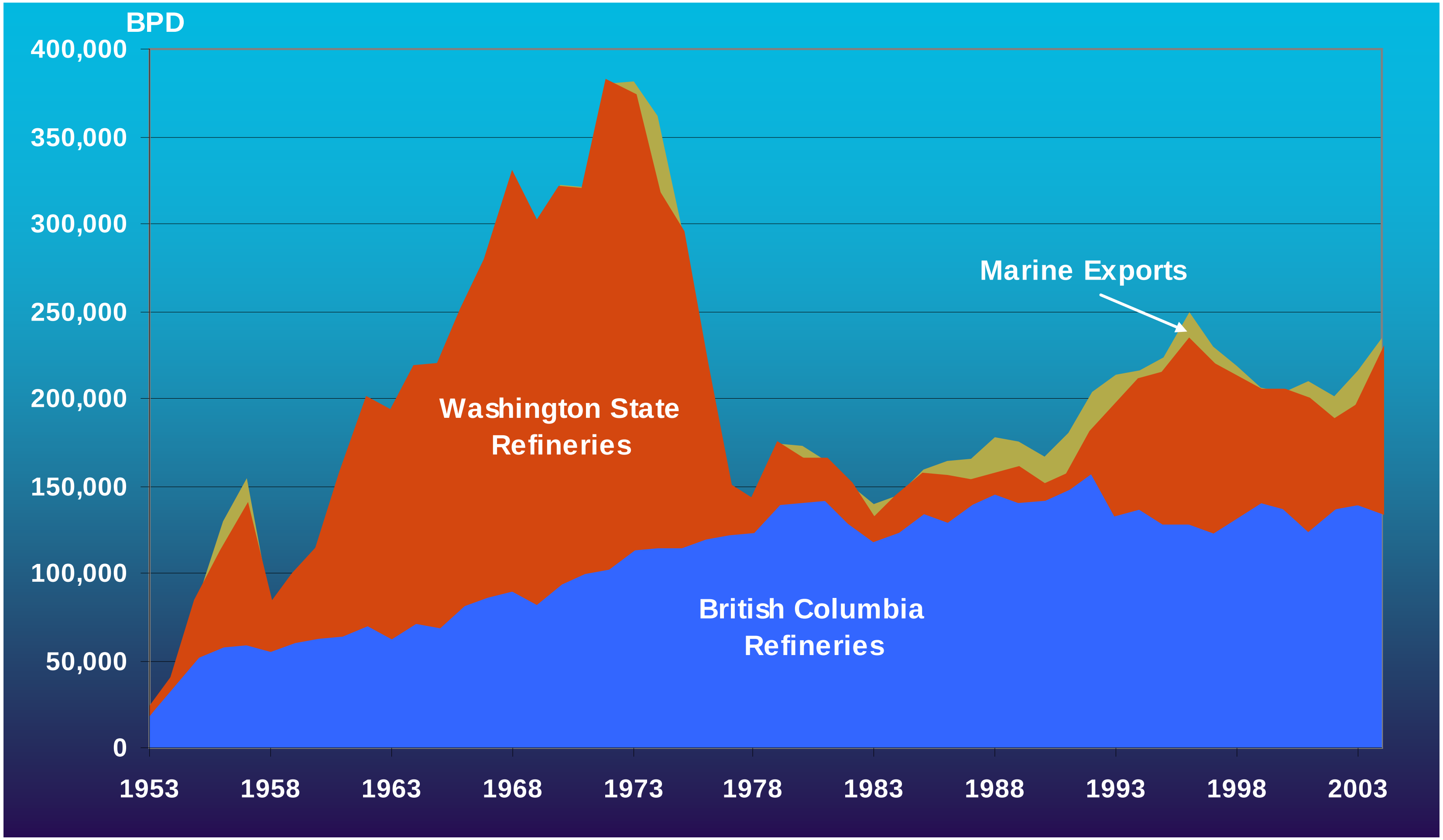
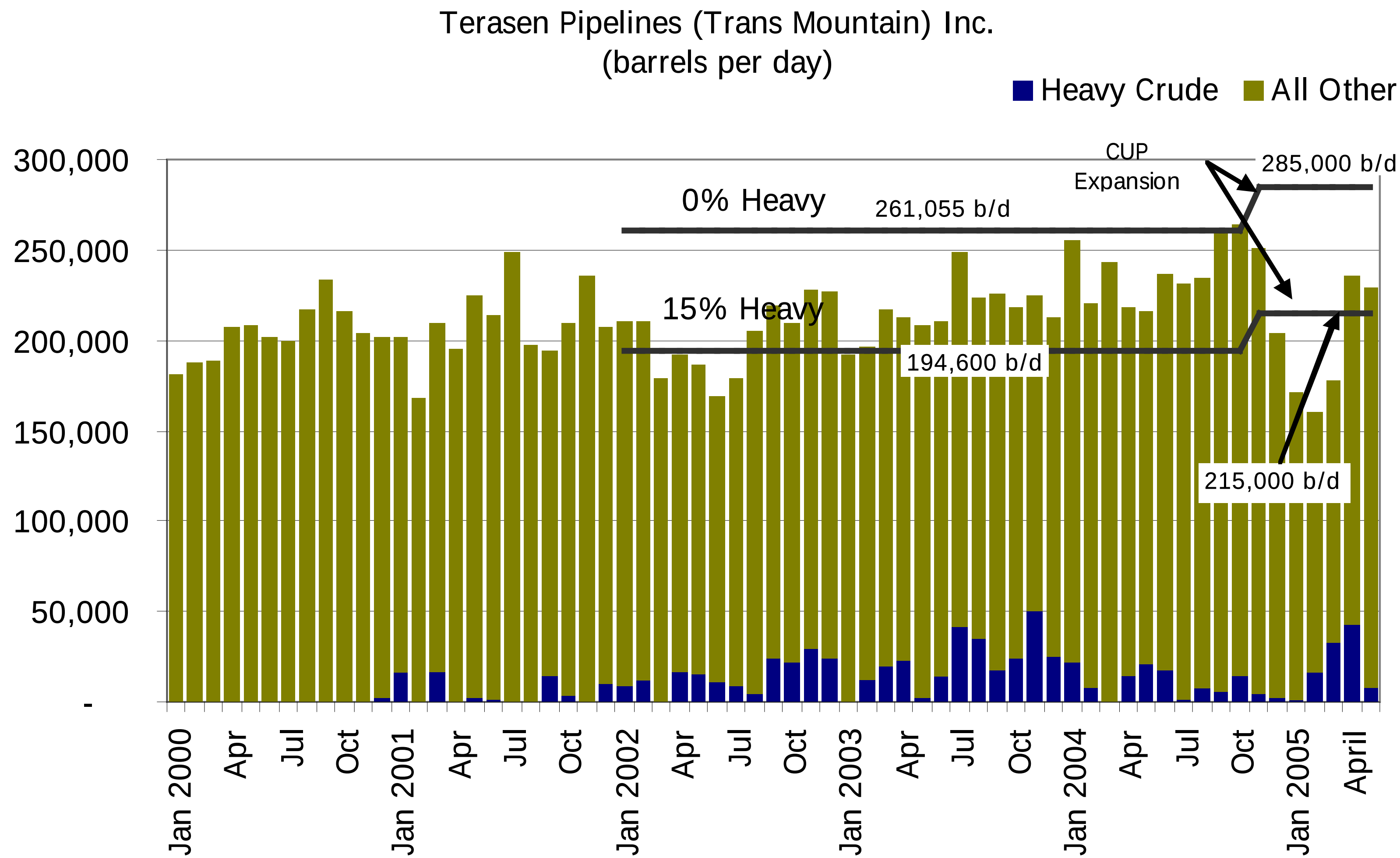
Trans Mountain - Regulatory

- Throughput growth has resulted in attractive returns from the 2001-2005 Incentive Toll Settlement
- ITS renewal discussions are underway
- Opportunity to meet shipper needs for more pipeline capacity provides negotiating flexibility

Trans Mountain Throughput



Trans Mountain Throughput



*May 2005 throughput based on forecast

Trans Mountain Throughput

- First quarter throughput affected by “perfect storm”:
  - Outages at both Syncrude and Suncor
  - Maintenance turnarounds at Chevron refinery and the Washington State refinery that takes the most Canadian crude
- April and May throughput has returned to apportionment
  - Despite continuing supply issues from the oilsands, and additional throughput on the Express system
  - Significant interest in tanker loadings in May

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Trans Mountain Expansion

- Oil sands production driving throughput growth
- Expansion can provide producers with greater access to California & Far East markets
- Completed 27,000 bpd expansion of the mainline at a cost of $19 million in October 2004

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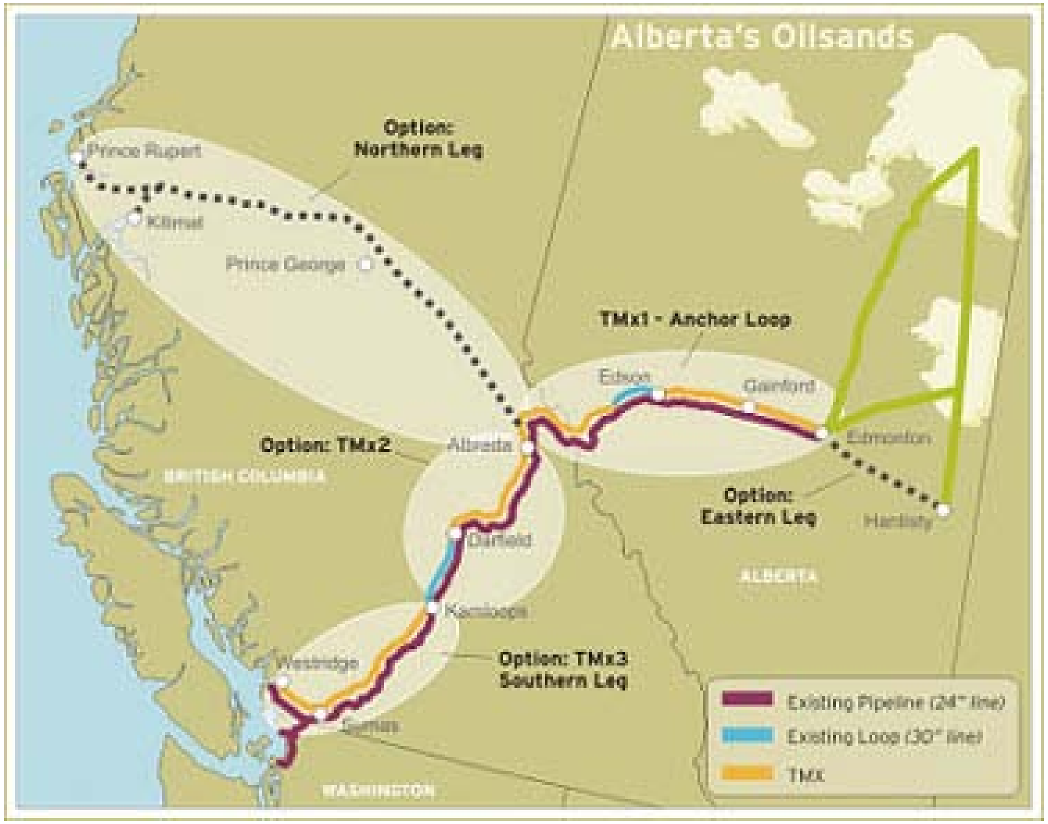
TMX Expansion



- Oilsands supply is actively seeking new markets
- Match with continued import growth on U.S. West Coast and Asia
- Expressions of Interest from potential shippers confirm demand for new capacity

TMx1 Expansion – Two Components

TMx1 Expansion – Two Components

- Pump Station Expansion Project
  - $205 million to add 35,000 bpd of pumping capacity for 2006
  - Currently discussing expedited shipper approvals
- Anchor Loop Project
  - $365 million to loop pipeline (40,000 bpd additional capacity) for 2008
  - Actively pursuing commercial discussions with shippers
  - Open season targeted for Q2/05

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TMX Expansion

- Further 550,000 bpd capacity to either Northern or Southern port
- TMx1 plus Southern option C$2.3 billion
- TMx1 plus Northern option C$2.6 billion
- Full range of potential options to match marketing plans of Producers

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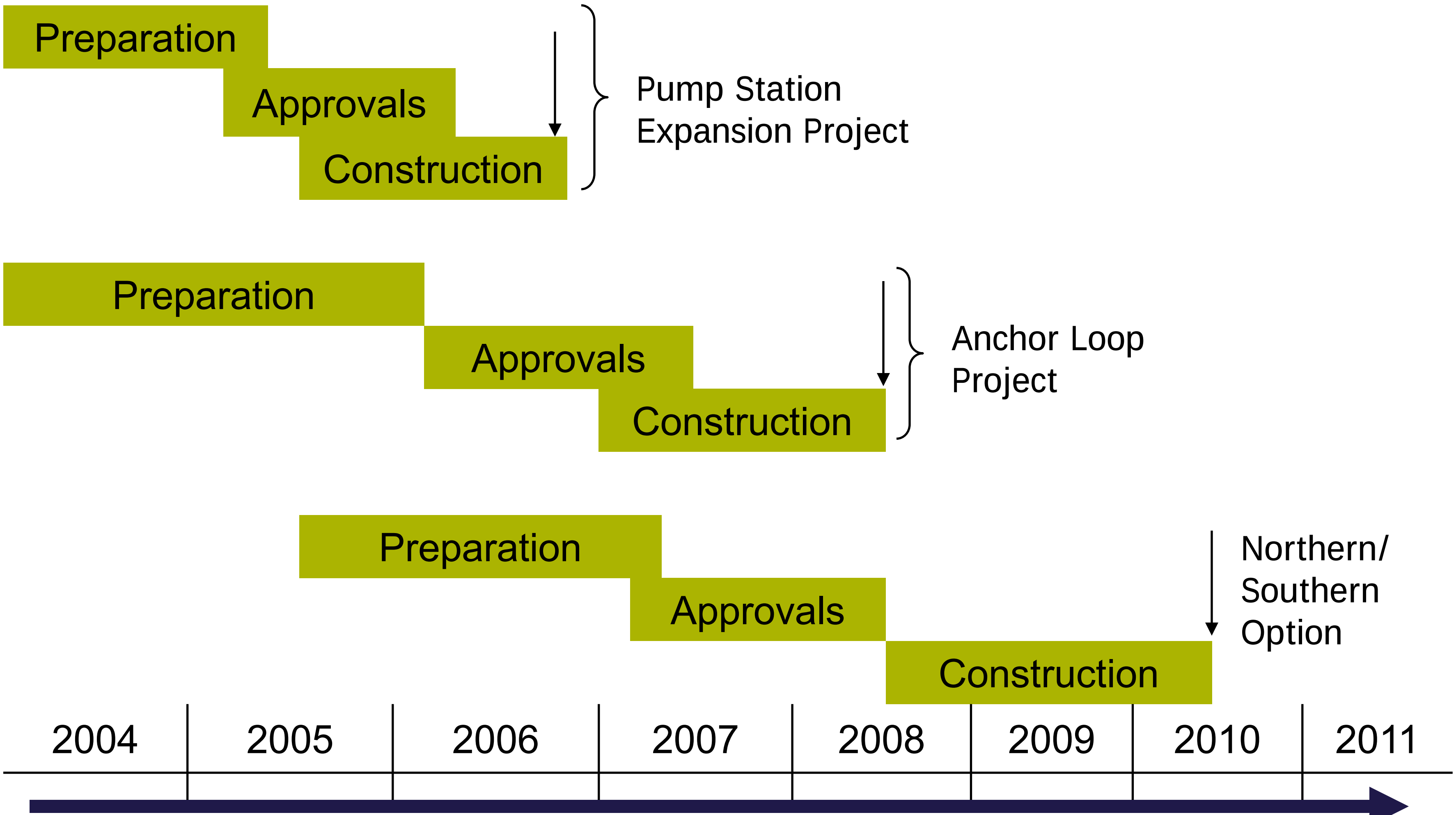
TMX Timing


Preparation
Approvals
Construction
Pump Station Expansion Project
Preparation
Approvals
Construction
Anchor Loop Project
Preparation
Approvals
Construction
Northern/ Southern Option
2004
2005
2006
2007
2008
2009
2010
2011

Corridor

- Completed on time and on budget in May 2003.
- Backed by 25 year ship-or-pay contract with Shell Canada (60%), Chevron (20%) and Western Oil Sands (20%).
- Provides for recovery of all operating costs, depreciation, taxes and financing costs in revenue requirement.
- 26% equity component, ROE is long-term Canada's plus 350 bps

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Corridor Expansion

- Linked to expansion plans for Athabasca Oil Sands Project
  - > Increase bitumen production to 290,000 bpd by 2010
- Will require looping of Corridor system
- Estimated cost $700-800 million, depending on configuration
- Opportunities for third party shipper volumes
- Status: Examining options with Corridor shippers

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Express

- Acquired January 2003
- 84% of the 280,000 post-expansion capacity is committed through long-term contracts.
- Express expansion
  - Feeds PADD IV demand
  - In-service April 2005
    - On-time and under budget

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Express – Business Developments

- Tie-in to Billings
  - $8 million project to interconnect with the ExxonMobil Silvertip Pipeline
  - Additional 14k bpd 10-year contract signed to support tie-in
- Platte de-bottlenecking
  - $6 million project to enhance capacity of the Platte pipeline and facilitate flows to PADD II
- Currently examining options for further expansion of the Express System, including new looping

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Contracted Capacity

Summary by Shipper

Shipper	Credit Rating	2007	2012	2014	2015
Alberta Government	AAA		15,000		
Canadian Natural	BBB+	3,000	3,000		
ConocoPhillips	A-		10,000	30,000	25,000
EnCana Crude Mktg.	BBB+		70,000		
[ ]	AAA				14,000
[ ]	BB		13,800		10,000
Sinclair Oil*	AAA				10,000
Suncor Energy	A				30,000
Talisman Energy	BBB+	1,000			
Total		4,000	111,800	30,000	89,000

*Internal rating

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Expansion Financing

- Excess proceeds of $10 million are being used to fund small expansions noted previously
- Process of converting Notes from Holdings level to System level is underway
- Result is that an additional $110 million of 6.09% Senior Secured Notes due January 2020 will be outstanding at the Express system level

Terasen

Terasen Gas Inc.

Presentation to Moody's

March 28, 2008

Contact Information

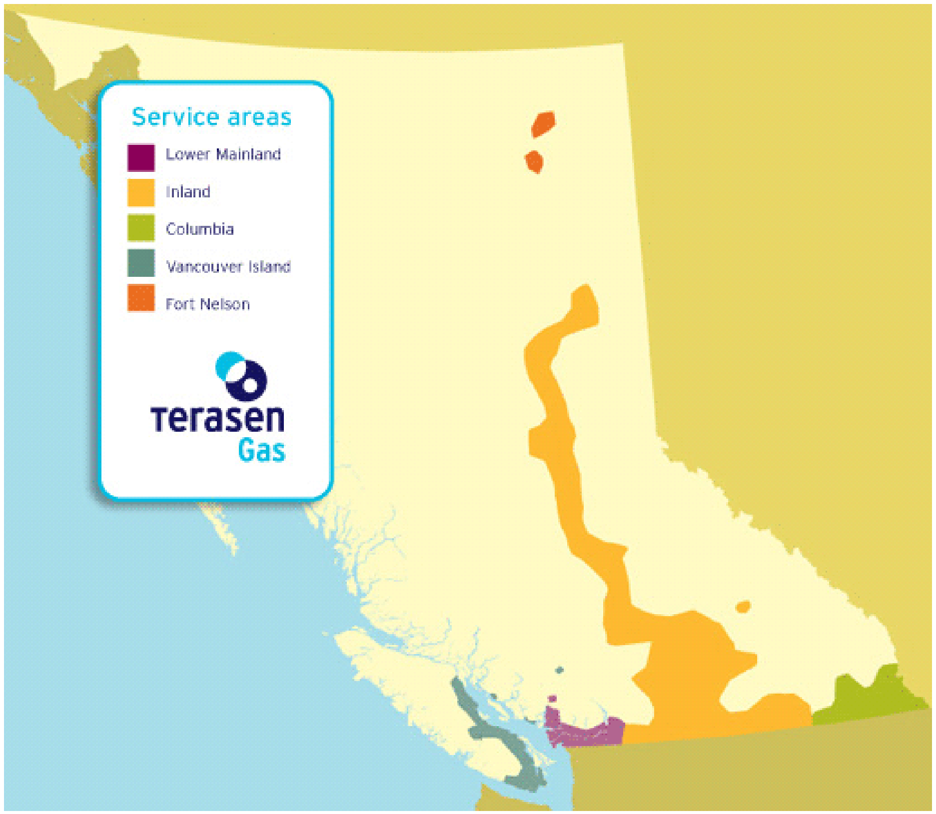
Roger Dall'Antonia
VP, Corporate Development & Treasurer
Terasen Inc.

Tel: (604) 443-6570
roger.dall'antonia@terasen.com

Presentation Overview

- Corporate Overview
- Terasen Gas Overview
- 2007 Financial Review
- 2008 to 2012 Financial Forecast

Terasen Gas Overview



* Map includes TGVI service areas

- Terasen Gas Inc. is a regulated natural gas transmission and distribution utility
  - Providing service to lower mainland, interior and northern areas of BC
  - Customer base of ~825,000
  - Rate base of ~$2.5 billion
- Experienced management team with significant energy industry expertise
- Strong ownership provide by Fortis Inc.
- Sister company to Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.
  - Combined, the three entities provide service to over 900,000 customers, ~96% of natural gas users in BC
  - TGI, TGVI and TGW share a common management and administrative structure with the cost allocation reviewed by BCUC
- Operates within a supportive regulatory environment, under the British Columbia Utilities Commission

Experienced Management Team

Terasen

Randy Jespersen
President & CEO

Doug Stout
VP, Marketing & Business Development

Jan Marston
VP, Gas Supply & Transmission

Dwain Bell
VP, Distribution

Daryle Britton
VP, Human Resources & Operational Governance

Bob Samels
VP, Business Services & CIO

Scott Thomson
VP, Regulatory Affairs & CFO

David Bennett
VP, General Counsel

Roger Dall'Antonia
VP, Corporate Development & Treasurer

Strong Ownership

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- Strong ownership through Fortis Inc.
  - the largest investor-owned utility-holding company in Canada
  - Gas and electric utilities
  - Over 2 million customers
  - Market capitalization of $4.5 billion

Fortis Inc.
DBRS: BBB(high) (stb)
S&P: A- (stb)

100% → **Fortis Alberta**
DBRS: A(low) (stb)
Moody's: Baa1 (stb)
S&P: A- (stb)

100% → **Fortis BC**
DBRS:BBB(high) (stb)
Moody's: Baa2 (stb)

100% → **Maritime Electric**
S&P:BBB+ (stb)

100% → **Nfld. Power**
DBRS: A (stb)
Moody's: Baa1 (stb)

100% → **Terasen Inc.**
DBRS: BBB(high) (stb)
Moody's: Baa2 (stb)
S&P: BBB+ (stb)

100% → **Terasen Gas Inc.**
DBRS: A (stb)
Moody's: A3 (stb)
S&P: A+ (stb)

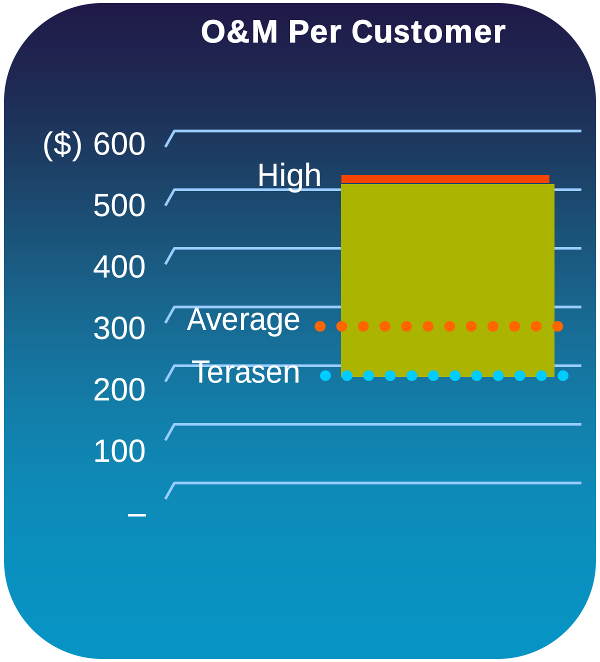
100% → **TGVI**
DBRS: BBB(high) (stb)
Moody's: A3 (stb)

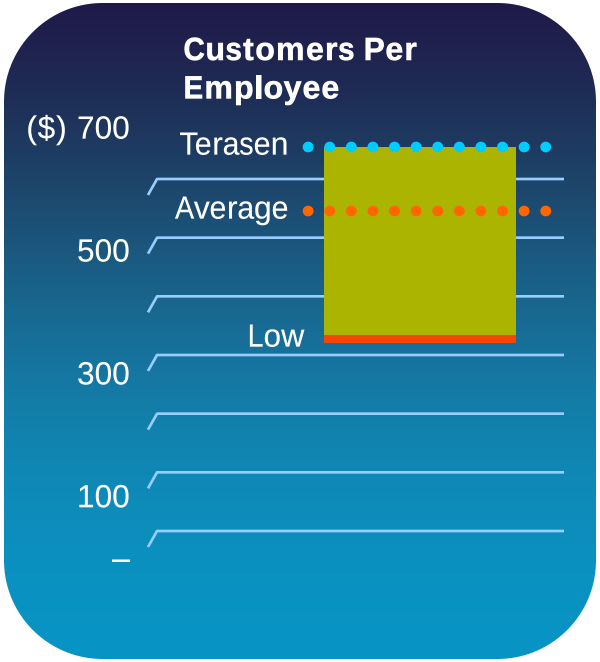
100% → **Terasen Gas (Whistler) Inc.**

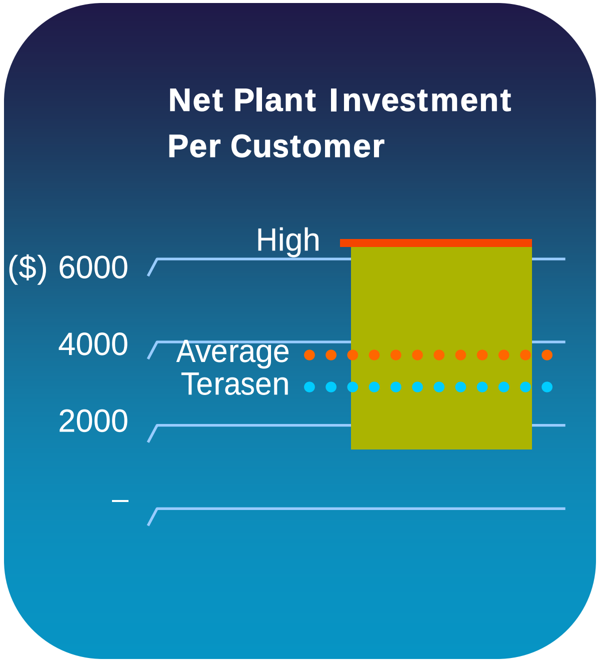
2007 Highlights

- Net Income of $78.2 million compared to $68.4 million for 2006
  - Surplus land sale, O&M and capital efficiencies offset lower allowed ROE
  - 2007 allowed ROE at 8.37% compared to 8.80% for 2006
- Continued customer growth due to population growth and economy
  - Net customer additions of ~10,000, similar to 2006
- Extension of PBR construct for 2008-2009 period
  - Incentive mechanism in place
  - Continuation of use of regulatory deferral accounts
- Amalgamation of Terasen Gas (Squamish) on blended rate base
- Issuance of $250 million debt during difficult market conditions
- Extended $500 million syndicated credit facility, including $100 million accordion feature allowing for rapid access to operating credit

Operating Efficiency



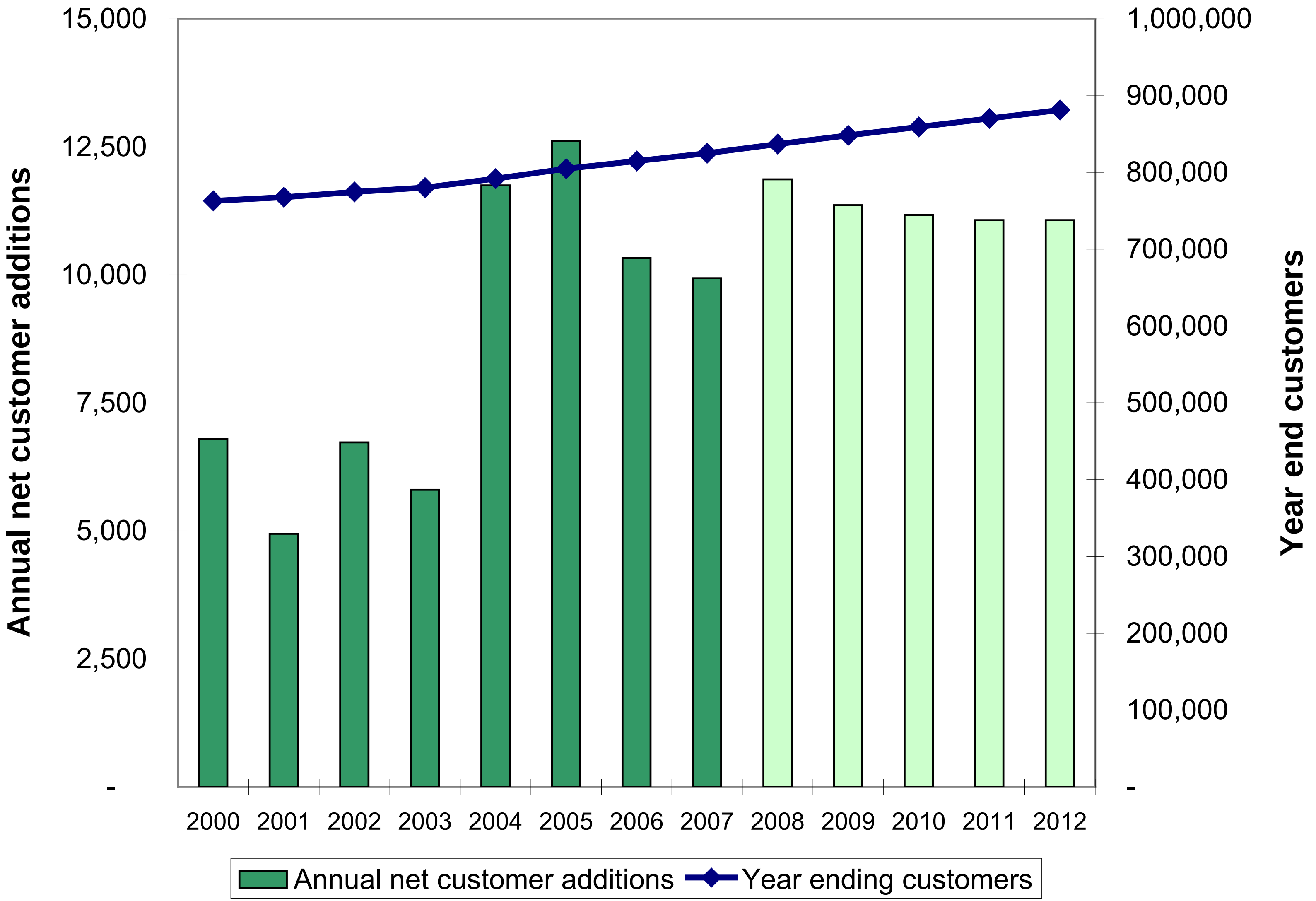




Source: LSM Consulting

Terasen Gas Estimates including TGI and TGVI

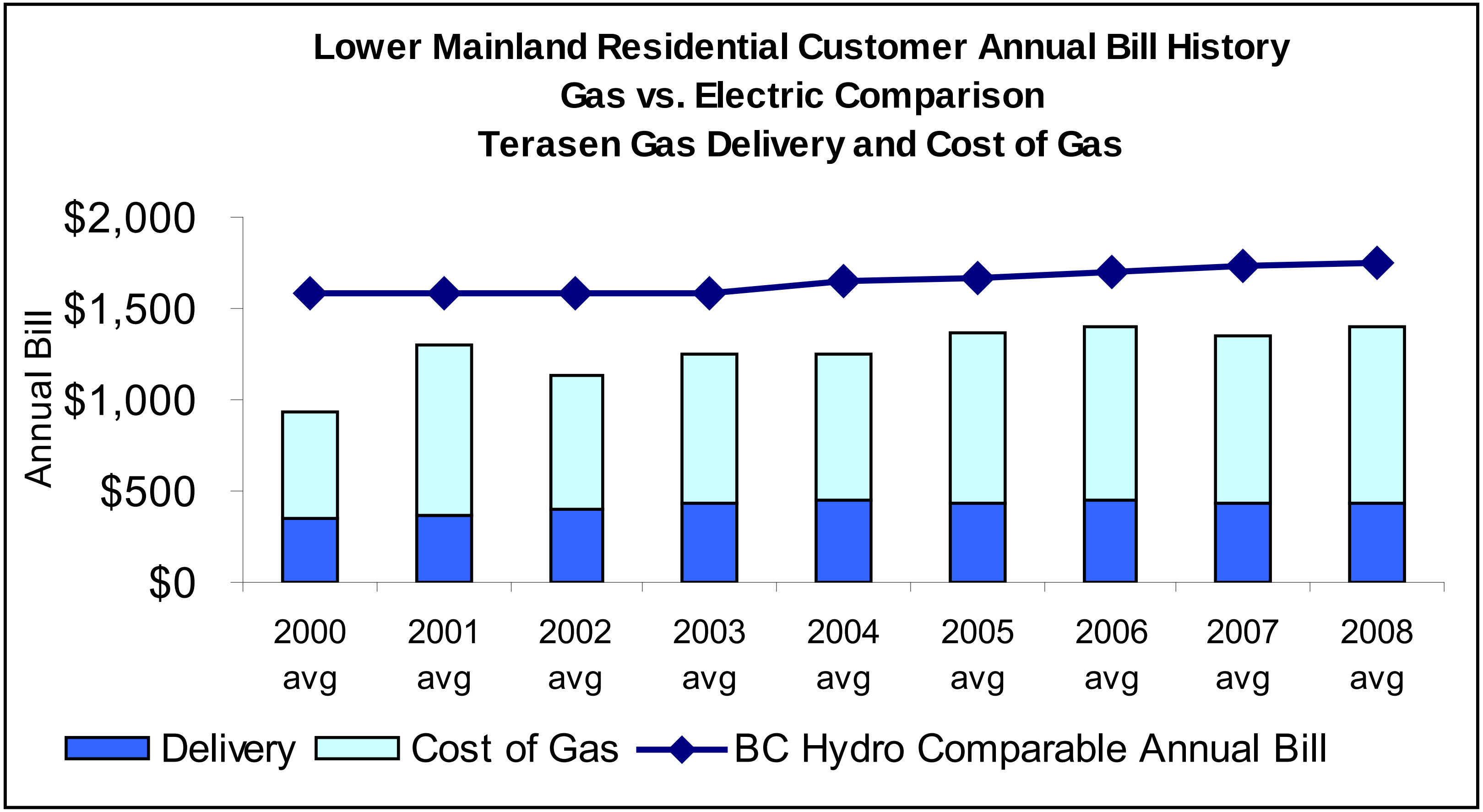
Customer Growth



Price Competitiveness

- Terasen Gas maintains a price advantage relative to electricity, the primary competitor to natural gas
- Increases in the market price of natural gas, combined with subsidized electricity prices, have in recent years eroded the historical advantage over electricity
- Terasen Gas maintains an active price risk management program (on behalf of customers with BCUC approval) which mitigates this risk
- Terasen Gas focus on operational efficiency has kept delivery charge component relatively flat over the last five years
- Introduction of Carbon Tax plus pressure on natural gas prices will create competitive pricing pressures
- BC Energy Plan focus on emission reduction and “clean-power” is expected to result in larger increases in electricity rates relative to recent experience

Price Competitiveness



Regulatory Arrangements

- 2004-2007 PBR previously in place for Terasen Gas extended through 2009
  - O&M and capital cost incentives, 50/50 sharing
  - Continuation of numerous deferral accounts
- Equity component for TGI 35.01% (post Terasen Squamish roll-in)
- Allowed ROE formula
  - 3.90% premium over forecast 30 year GoC yield
  - Risk premium adjusted by 75% of change in forecast yield year over year
  - 2008 allowed ROE set at 8.62%, up from 8.37% allowed ROE for 2007

BCUC Ring Fencing

- BCUC in April 30, 2007 Order approving the Fortis acquisition specified certain ring-fencing conditions
  - Maintain a common equity to total capital ratio at least as high as the level determined by BCUC
  - No dividends without BCUC approval if equity:capital ratio would be violated
  - Restrictions on interaction with affiliates (separate cash management, no financial support, no tax sharing, transactions only on an arms length basis)
  - No financial support or guarantee of non-regulated businesses
  - Maintain existing governance policies, in particular, independence of Directors

Terasen Gas - Outlook

- Financial performance will continue to be predictable
- Focus will be on increasing customer capture rates and retaining customers
  - Opportunity to focus on multi-family dwellings
  - Regional economy remains strong, expected to continue through 2010
- Focus on retaining customers through expanded energy conservation and efficiency programs
- Pursuing fair return for natural gas utilities in Canada
  - 2008 allowed ROE 8.62%, up from 8.37% 2007
- Planning underway for potential replacement of current PBR
- Infrastructure opportunities focused on transmission and CIS
  - Inland Pacific Connector potential for 2012
  - Reviewing AMI/AMR infrastructure opportunities

Terasen Gas Inc.

Presentation to Moody's

April 3, 2009

Contact Information

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VP, Corporate Development & Treasurer
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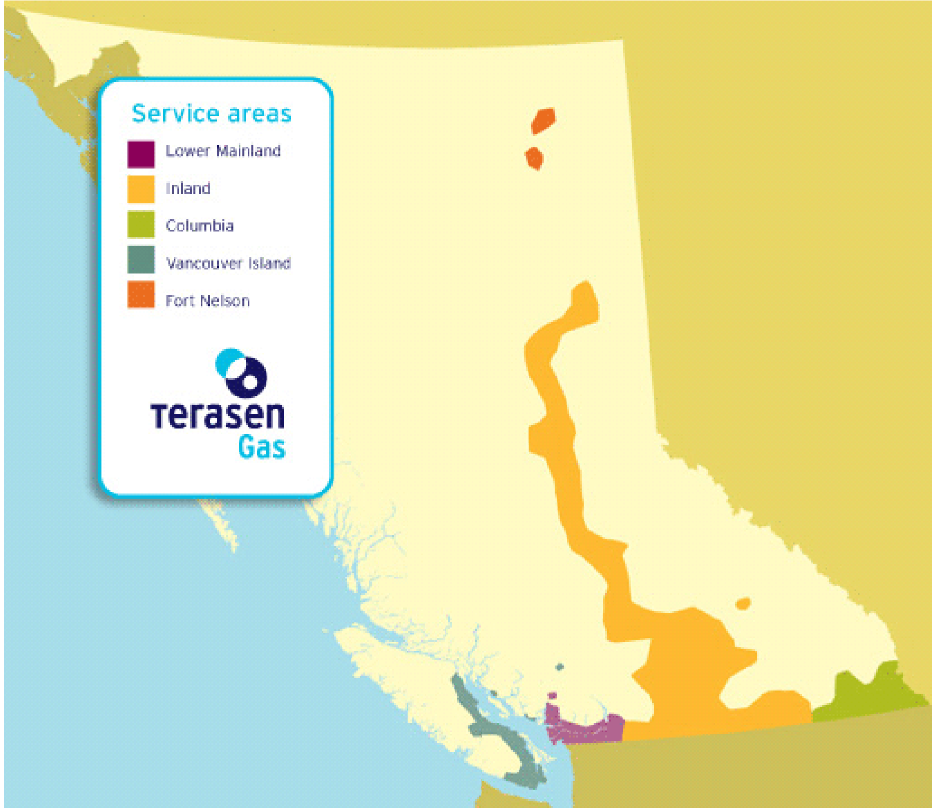

* Map includes TGVI service areas

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  - Customer base of ~834,000
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- Experienced management team with significant energy industry expertise
- Strong ownership provided by Fortis Inc.
- Sister company to Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.
  - Combined, the three entities provide service to over 931,000 customers, ~96% of natural gas users in BC
  - TGI, TGVI and TGW share a common management and administrative structure with the cost allocation reviewed by BCUC
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terasen

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terasen

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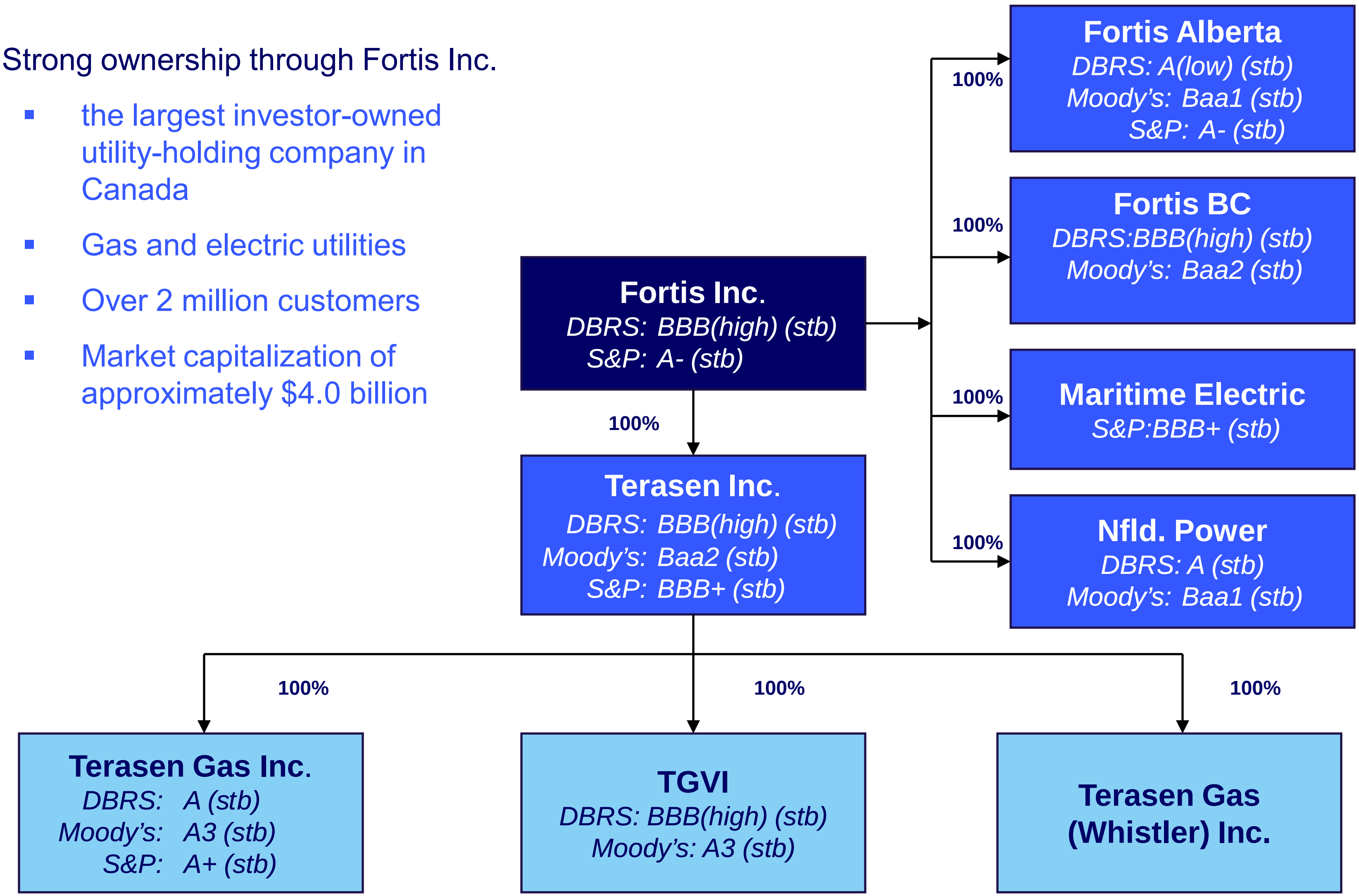


Common Management Structure

- Ownership and Operatorship
  - In addition to TGI, Terasen Inc. also owns and operates TGVI and Terasen Gas (Whistler) (“TGW”), which provides service to the Whistler region

	TGI	TGVI	TGW	Total
Customers	**834,226**	**94,778**	**2,457**	**931,461**
% BC Natural Gas Users	**86%**	**10%**	**<1%**	**~96%**
Pipeline Network (km)	**39,899**	**6,098**	**132**	**46,129**
2009 Estimated Rate Base (mm)	**$2,547**	**$514**	**$39**	**$3,100**
Assets (mm)	**$3,109**	**$697**	**$24**	**$3,830**

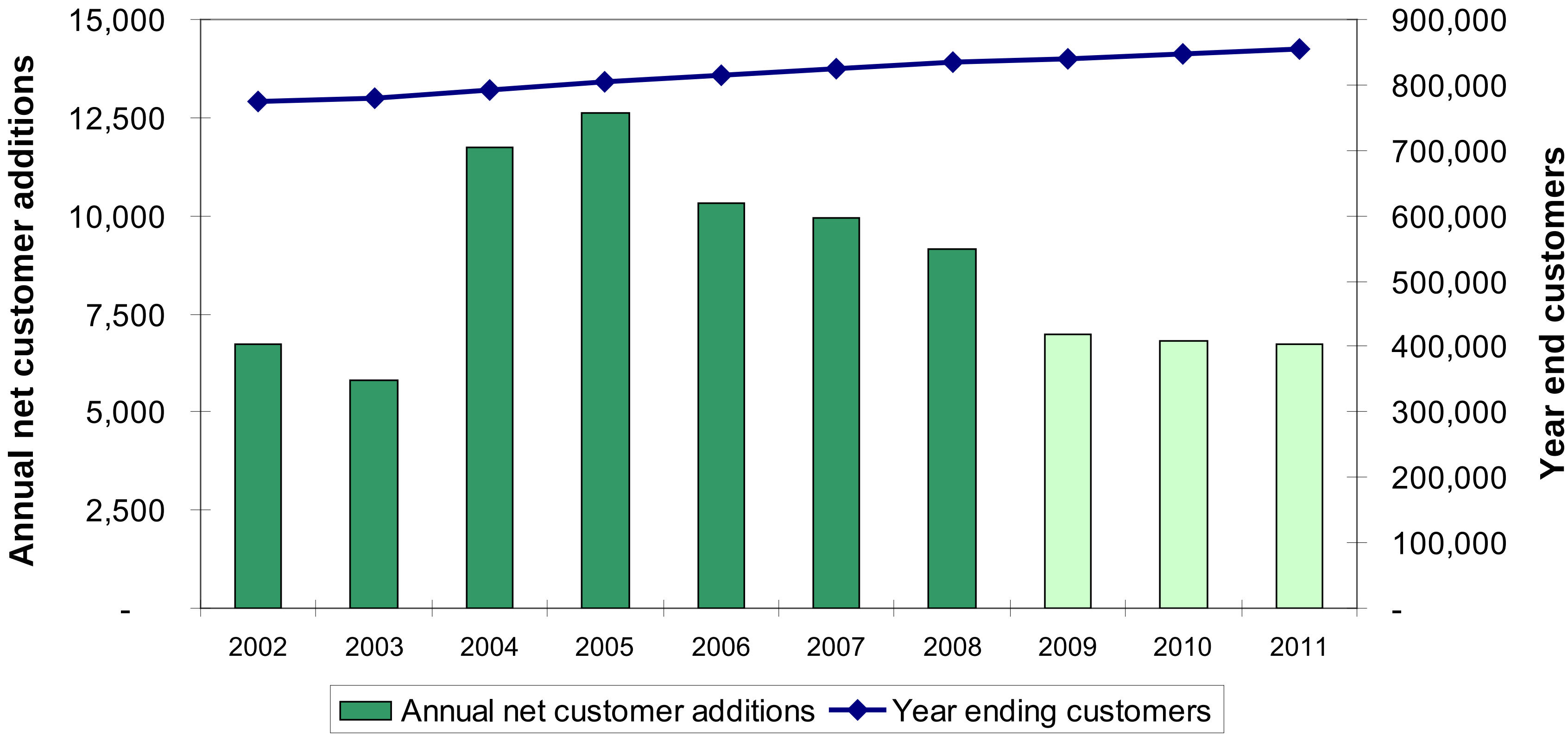
  - TGI, TGVI and TGW share a common management and administrative structure with the cost allocation reviewed by BCUC

2008 Highlights

Terasen

- Net Income of $91.5 million compared to $78.2 million for 2007
  - 2008 results include settlements with CRA of $11.6 million
  - 2008 allowed ROE at 8.62% compared to 8.37% for 2007
- Continued customer growth but a lower rate of additions due to a slowing economy in British Columbia
  - Net customer additions of ~9,000
- Extension of PBR construct for 2008-2009 period
  - Incentive mechanism in place
  - Continuation of use of regulatory deferral accounts
- Issuance of $250 million debt in 2008
- Extended existing $500 million syndicated credit facility by one year to 2013

Customer Growth



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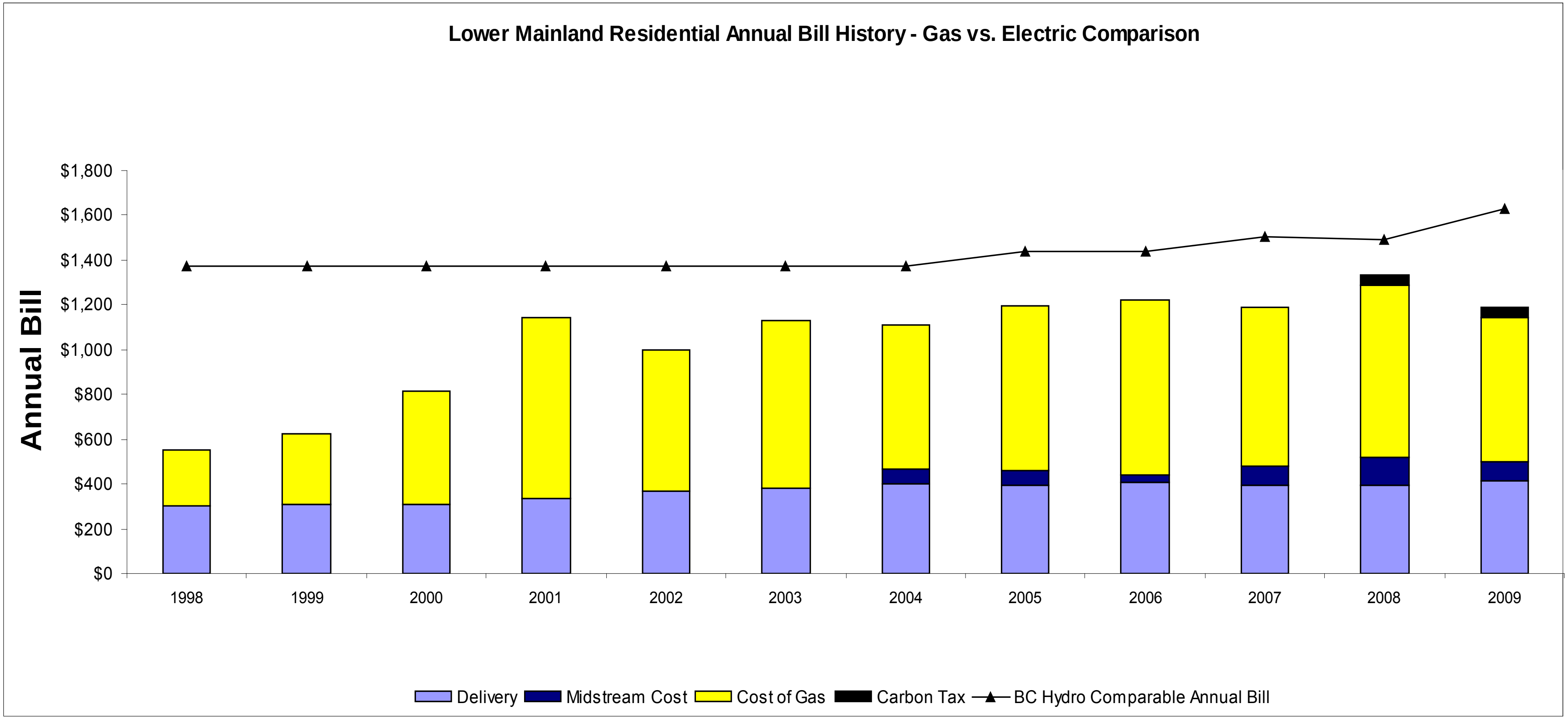
- Terasen Gas maintains an active price risk management program (on behalf of customers with BCUC approval) which mitigates this risk
- Terasen Gas focus on operational efficiency has kept delivery charge component relatively flat over the last five years
- BC Energy Plan focus on emission reduction and “clean-power”:
  - Expected to result in larger increases in electricity rates relative to recent experience;
  - However emmissions reduction focus will put pressure on natural gas demand

Price Competitiveness

terasen



Assumes:

Natural gas use of 95 GJ

Efficiency of gas equipment is 90% relative to 100% for electricity

Terasen Gas amount includes the basic charge

BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

Regulatory Arrangements

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  - O&M and capital cost incentives, 50/50 sharing
  - Continuation of numerous deferral accounts
- Equity component for TGI 35.01% (post Terasen Squamish roll-in)
- Allowed ROE formula
  - 3.90% premium over forecast 30 year GoC yield at a base level of 5.25%
  - Current GoC yields suggest a lower ROE in 2010
  - Risk premium adjusted by 75% of change in forecast yield year over year
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  - No dividends without BCUC approval if equity:capital ratio would be violated
  - Restrictions on interaction with affiliates (separate cash management, no financial support, no tax sharing, transactions only on an arms length basis)
  - No financial support or guarantee of non-regulated businesses
  - Maintain existing governance policies, in particular, independence of Directors

Terasen Gas - Outlook

- Near term financial performance expected to be predictable
- Lower customer growth than in the past few years due to a slowing economy and fewer new housing starts
- Focus will be on increasing customer capture rates and retaining customers
- Focus on retaining customers through expanded energy conservation and efficiency programs
- Planning for ROE/Capital structure application in 2009
  - 2009 allowed ROE 8.47%, down from 8.62% 2008
  - Based on current GoC yields, formula ROE would be 7.92% as of the end of March 2009
- Planning underway for a Revenue Requirement Application in mid 2009
- In 2011, the Company will transition to IFRS and this may create significant volatility in the earnings

Attachment 86.2

Attachment 86.3

Attachment 86.4

Attachment 86.5.1

Credit Opinion: **Terasen Gas (Vancouver Island) Inc.**

Terasen Gas (Vancouver Island) Inc.

Canada

Ratings

Category	**Moody's Rating**
Outlook	Stable
Senior Unsecured -Dom Curr	A3

Contacts

Analyst	**Phone**
Allan McLean/Toronto	416.214.3852
William L. Hess/New York	212.553.3837

Key Indicators

Terasen Gas (Vancouver Island) Inc.

	[1]**LTM**	**2007**	**2006**	**2005**	**2004**
ROE (%) [2]	**10.5%**	**10.5%**	**10.8%**	**10.9%**	**9.4%**
EBIT/Customer Base (US$) [3]	[4]**$ 654.0**	**$583.6**	**$508.8**	**$510.6**	**$462.1**
EBIT/Interest (x)	**2.7x**	**2.9x**	**2.6x**	**2.7x**	**2.3x**
RCF/Debt (%)	**11.5%**	**8.6%**	**10.6%**	**11.4%**	**11.2%**
Debt/Book Capitalization (Excluding Goodwill) (%)	**66.7%**	**67.5%**	**65.9%**	**64.5%**	**66.2%**
FCF/FFO (%)	**-25.3%**	**-68.0%**	**38.8%**	**-5.4%**	**10.3%**

[1] To September 30, 2008 [2] Return on Average Equity [3] US$ EBIT/ Residential and Commerical Customers (Ex. Industrial) [4] EBIT/Customer base figures for the last twelve months ended September 30, 2008 are based on the most recent available customer figures (i.e. December 31, 2007)

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Relatively low-risk, cost of service regulated gas transmission and distribution utility with no unregulated operations.

Small customer base, high cost system and relatively weak credit metrics are balanced by a history of strong regulatory and political support.

Expiry of government subsidies in 2011 could cause TGVI's rates to be uncompetitive with alternate forms of energy and lead to fuel switching.

Development of Mt. Hayes LNG storage facility.

Strong regulatory ring-fencing mechanisms.

Corporate Profile

Headquartered in Surrey, British Columbia, Terasen Gas (Vancouver Island) Inc. (TGVI) is a regulated natural gas transmission and distribution utility serving approximately 95,000 customers on Vancouver Island and the Sunshine Coast. TGVI, which has no unregulated operations, is regulated on a cost of service basis by the British Columbia Utilities Commission (BCUC). TGVI is one of the smallest gas utilities rated by Moody's with a 2008 mid-year rate base of approximately $500 million.

TGVI is a wholly-owned subsidiary of Terasen Inc. (TER), a holding company which also owns 100% of Terasen Gas Inc. (TGI) and Terasen Gas Whistler Inc. (TGW), and a 30% interest in CustomerWorks, L.P. TER, and consequently TGVI, has been an indirect, wholly-owned subsidiary of Fortis Inc. (FTS) since May 17, 2007.

SUMMARY RATING RATIONALE

TGVI's A3 senior unsecured rating and stable outlook reflect TGVI's relatively low-risk business model and supportive regulatory and political environment balanced by normalized credit metrics that are generally in the Baa category. TGVI's normalized financial metrics are generally weaker than those of similarly rated U.S. local distribution company (LDC) peers such as Connecticut Natural Gas Corporation, Northwest Natural Gas Company, Piedmont Natural Gas Company, Inc. and UGI Utilities, Inc. However, TGVI's financial metrics are somewhat stronger than those of its sister company, TGI (A3, senior unsecured), reflecting the fact that the BCUC deems a higher level of equity for TGVI (40% vs. TGI's 35%) and allows a higher ROE (70 BP premium to TGI). Moody's recognizes that the weaker financial metrics of TGVI and TGI relative to similarly rated U.S. peers are largely a function of the relatively lower deemed equity and allowed ROE permitted by the BCUC. Moody's believes that this is offset to a significant degree by the supportiveness of the business and regulatory environments in Canada generally and in British Columbia specifically. While Moody's quantitative analysis has considered TGVI's historical and forecast financial performance, Moody's believes that TGVI's historical metrics are probably not representative of future performance due to the impact of regulatory deferrals and recoveries as well as government subsidies. Similarly, TGVI's near-term financial forecast is distorted by ongoing recovery of regulatory deferrals, the termination of government subsidies in 2011, and elevated capital expenditures. Accordingly, Moody's has focused on a set of normalized credit metrics that remove these distortions. While Moody's does not entirely discount the potential risks associated with TGVI's unique business and regulatory situation and its planned capital expenditures, we believe that these risks are manageable. Utilizing the normalized set of financial metrics, Moody's rating methodology for North American Regulated Gas Distribution Companies indicates an A3 rating for TGVI which mirrors TGVI's actual A3 senior unsecured rating.

DETAILED RATING CONSIDERATIONS

RELATIVELY LOW-RISK REGULATED GAS TRANSMISSION AND DISTRIBUTION UTILITY IN A SUPPORTIVE ENVIRONMENT

In general, Moody's considers gas distribution utilities to be at the low end of the risk spectrum within the universe of regulated utilities, both gas and electric. Similarly, we consider regulated utilities be generally lower risk relative to companies that are outside of the utility space and do not benefit from cost of service regulation. Accordingly, Moody's considers regulated gas LDCs like TGVI to be among the lowest risk corporate entities. Nevertheless, two key features of TGVI's operations cause its business risk to be higher than most gas LDCs. Firstly, TGVI's system has a relatively high capital cost on a per customer basis reflecting the significant investment in transmission infrastructure, including three sub-sea crossings, to reach the relatively small customer base on Vancouver Island. Secondly, as a consequence of the high capital cost of TGVI's system, its costs of service and therefore its rates are high. To ensure that natural gas was roughly cost competitive with fuel oil and electricity, the Province, the BCUC and TGVI agreed to cap TGVI's rates at levels similar to those of alternative forms of energy. Prior to 2003, TGVI's rates were insufficient to cover TGVI's costs of service and the shortfall was deferred in the Revenue Deficiency Deferral Account (RDDA). TGVI financed the increases in the RDDA balance by issuing Class B subordinated debt instruments which were purchased by TER.

While the high cost of TGVI's system and the historically uncompetitive position of gas on Vancouver Island cause TGVI's business risk to be higher than that of most gas LDCs, Moody's believes that this higher risk and TGVI's relatively weak credit metrics are balanced by a long history of government support and a supportive regulatory environment. In support of its policy goal of ensuring the availability of natural gas on Vancouver Island, the Province of British Columbia has provided both financial and regulatory support to TGVI and its predecessors virtually since their inception. In the past, both the Province and the Federal Government have provided financial support to TGVI in the form of non-interest bearing loans. Ongoing Provincial support is provided through the Vancouver Island Natural Gas Pipeline Agreement (VINGPA) under which the Province pays royalty revenues to TGVI that subsidize the cost of natural gas. The Province also provides regulatory support in the form of the Special Direction to the BCUC which governs the recovery of RDDA balances. Beginning in 2003, TGVI reached a point where, with the benefit of the Provincial royalty revenues, it was able to not only recover its costs of service but begin recovering the accumulated regulatory assets (principally the RDDA) while charging rates that were roughly competitive with costs of alternative sources of energy on Vancouver Island. The terms of the Special Direction dictate that it will not expire before the RDDA balance has been fully recovered.

As the RDDA balance is recovered, TGVI utilizes the cash recovered to retire the Class B subordinated debt instruments purchased by TER. TGVI currently anticipates that it will have fully recovered the RDDA balance by early 2010 which, all else being equal, is expected to result in a slight reduction in TGVI's rates in 2010. However, TGVI's rates are expected to increase substantially in 2012 to compensate for the lack of Provincial royalty revenues which are scheduled to terminate in 2011. While Moody's anticipates that TGVI may seek regulatory approval for some mechanism to smooth out these potential rate fluctuations, there can be no assurance that the BCUC would agree to any proposals that TGVI might make. In the absence of some smoothing mechanism, TGVI's rates during the 2010 to 2012 period are expected to be somewhat volatile.

In addition to support provided by the Provincial Government, TGVI has benefited from British Columbia's economic performance, which has until recently been relatively strong. Moody's considers Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, the regulatory environment in the Province of British Columbia is considered one of the more supportive in Canada. This view reflects the fact that regulatory proceedings tend to be less adversarial and decisions tend to be timely and balanced although these relative strengths have been tempered somewhat by deemed equity levels and allowed ROEs that have tended to be lower than in other Canadian provinces. TGVI benefits from deemed equity levels and allowed ROEs for ratemaking purposes that are higher than those of its A3-rated sister company, TGI. For rate-making purposes, the BCUC allows TGVI a deemed equity component of 40% vs. TGI's 35% and an allowed ROE that is 70 BP higher than TGI's which tends to cause TGVI's financial metrics to be somewhat stronger than those of TGI. TGVI's more favourable rate-making inputs relative to those of TGI reflect the relatively small size of TGVI's service territory and customer base as well as its relatively high investment in fixed assets on a per customer basis. TGVI's current rate settlement expires at the end 2009 and the company expects to file a two year rate application around mid-year 2009. With the expected elimination of the RDDA balance in 2010, Moody's expects that TGVI will seek and receive regulatory protection against key business risks such as commodity prices, customer demand, interest expense, pension costs and insurance costs. TGVI's sister company, TGI, currently benefits from regulatory protection against such risks.

EXPIRY OF GOVERNMENT ROYALTY REVENUES IN 2011 ADVERSELY IMPACTS COMPETITVENESS OF GAS RELATIVE TO ALTERNATE FORMS OF ENERGY

A material risk faced by TGVI is the competitiveness of natural gas relative to alternative forms of energy on Vancouver Island. As noted above, the development of TGVI's system was relatively expensive and only in recent years has TGVI accumulated a sufficiently large customer base to permit it to recover from ratepayers both its current costs of service and accumulated regulatory deferrals while charging rates that have been comparable to the costs of alternative forms of energy on Vancouver Island. Furthermore, TGVI has only been able to do this with the benefit of Provincial royalty revenues. The rate increases that will be required to offset the loss of Provincial royalty revenues post-2011 could cause TGVI's rates to exceed the cost of alternative forms of energy. However, we expect that the costs of alternative energy sources are likely to rise significantly over an extended period of time which could provide TGVI with some breathing room.

Nevertheless, if TGVI ultimately finds itself in a position where its rates are uncompetitive and ratepayers begin to use less gas or even convert to electricity or fuel oil, Moody's expects that TGVI and its ultimate shareholder, FTS, would seek to merge TGVI with TGI and harmonize their rates. Rate harmonization would be expected to eliminate the cost disadvantage of gas on Vancouver Island as the higher costs of TGVI's system would be spread across TGI's larger base of approximately 834,000 customers (roughly nine times the customer base of TGVI).

Clearly, FTS would be supportive of such a move as a means of preserving the value of its investment in TGVI, but Moody's also believes that the Province of British Columbia would likely be supportive as well. As noted above, the Province has long provided financial and regulatory support to TGVI in order to promote its policy goal of ensuring availability of gas on Vancouver Island. While Provincial support of amalgamation/rate harmonization is not assured, it is Moody's view that it is unlikely that the Province would simply stand by and allow the Vancouver Island gas distribution infrastructure to falter and fail given the Province's well established track-record of supporting the development of TGVI's franchise. Moody's also notes that there is precedence for such a transaction within the Terasen group of companies: on November 2, 2006, Terasen Gas (Squamish) Inc. was amalgamated with TGI and the rates of the two entities were harmonized. While TGVI is considerably larger than Terasen Gas (Squamish), we believe the Squamish transaction is a positive precedent in the event that at some point in the future, the long-term competitiveness of TGVI's rates comes into question.

DEVELOPMENT OF MT. HAYES LNG STORAGE FACILITY

In November 2007, TGVI received conditional approval from the BCUC for the 1.5 billion cubic foot Mt. Hayes liquefied natural gas (LNG) storage facility. TGVI commenced construction of the project in 2008. Based on a cost estimate of approximately $215 million, including an allowance for funds used during construction (AFUDC), the value of the project would exceed 40% of the value of TGVI's 2008 mid-year rate base of $500 million. However, Moody's believes that this measurement overstates both the magnitude and importance of the project for a number of reasons. Firstly, Mt. Hayes is being constructed under an Engineering Procurement Construction (EPC) contract which has shifted much of the cost and schedule risk to the EPC contractor, Chicago Bridge & Iron (CB&I), who has successfully constructed a number of similar LNG projects. Secondly, by early 2009, TGVI had hedged the majority of the Mt. Hayes cost elements that were not transferred to CB&I under the EPC contract. As of early 2009, the project was on budget, on schedule and within the $200 million pre-AFUDC cost parameters established by the BCUC. Thirdly, the project will form part of TGVI's rate base but TGVI has entered into BCUC-approved 35 year contract with TGI under which TGI will pay for approximately two thirds of the facility's capacity in the early years of the contract. Therefore, initially only about a third of the project costs will be borne by TGVI's existing ratepayers. Over time, as TGVI grows and requires a greater share of Mt. Hayes' capacity, TGVI's ratepayers will be required to support an increasing share of the project's costs. Fourthly, Mt. Hayes is a rather modest project both in absolute terms and relative to the experience and expertise of TGVI's management team (TGVI shares a common management team with TGI, a utility with a rate base of approximately $2.5 billion). For these reasons, Moody's does not expect that the Mt. Hayes project will pose a significant credit challenge for TGVI.

TGVI expects to finance the development of Mt. Hayes primarily with debt until the project enters service and rate base which is currently expected to occur in 2011. Accordingly, during the construction period, TGVI's debt to capital will be elevated and its cash flow metrics will be depressed.

STRONG REGULATORY RING-FENCING SEPARATES TGVI FROM PARENT, TERASEN INC.

Moody's believes that TGVI's ring-fencing is very good relative to that of its peers outside of British Columbia. TGVI is subject to a set of regulatory ring-fencing conditions imposed by the BCUC (refer to Moody's October 14, 2005 Comment on Proposed Regulatory Ring-Fencing Conditions). The ring-fencing conditions provide that, unless otherwise approved by the BCUC, TGVI shall: maintain a ratio of common equity to total capital at least as high as the deemed equity capitalization utilized by the BCUC for ratemaking purposes (currently 40%); not pay dividends if they would cause TGVI's common equity to total capital to fall below the BCUC's deemed equity percentage; not invest in or financially support non-regulated business; and not engage in affiliate transactions on anything other than an arm's length basis. Moody's believes that the BCUC ring-fencing provisions effectively insulate TGVI from the greater financial and business risks of its parents, TER and FTS. The regulatory ring-fencing provisions, combined with FTS' philosophy of requiring its utility operating subsidiaries to be operationally and financially independent of FTS and other subsidiaries, allow Moody's to evaluate TGVI's credit profile on a stand-alone basis.

Liquidity Profile

Moody's believes that TGVI has sufficient liquidity resources to meet its needs in 2009. In evaluating a company's liquidity, Moody's typically assumes that the company loses access to new capital, other than amounts available under its committed credit agreements, for a period of 12 months. In this context, we then evaluate the company's various sources and uses of cash including the flexibility to defer or reduce uses of cash such as capital expenditures and dividends.

TGVI maintains a $350 million syndicated committed revolving credit agreement which matures on January 13, 2011. The credit agreement contains two maintenance covenants (debt to equity not greater than 70% and EBIT to interest expense not less than 2:1). As at September 30, 2008, TGVI's leverage and coverage were 63.2% and 3.89x, respectively, leaving significant headroom under the covenants. TGVI's credit agreement does not contain language such as a Material Adverse Change (MAC) clause or ratings triggers that would inhibit access to the unutilized portion of the facility in situations of financial stress. Moody's understands that at December 31, 2008, approximately $235 million was available under the $350 million committed facility reflecting approximately $115 million drawn against this facility.

TGVI is expected to generate approximately $40 million of adjusted funds from operations (FFO) in 2009. After dividends in the range of $20 million and capital expenditures and working capital changes of approximately $80 million, Moody's expects TGVI to be free cash flow (FCF) negative by approximately $60 million in 2009. Given the forecasted $60 million FCF shortfall and repayment of approximately $21 million Class B Instruments, TGVI's 2009 funding requirement is expected to be approximately $81 million. This is substantially less than the availability of approximately $235 million under TGVI's syndicated bank credit facility at December 31, 2008.

Rating Outlook

The stable outlook is predicated on TGVI's low business risk as a regulated gas distribution utility, the expectation that the Mt. Hayes project will be successfully completed on time and on budget and the expectation that TGVI will be able to recover its costs of service while charging rates competitive with the costs of alternative forms of energy following the cessation of provincial royalty revenues in 2011.

What Could Change the Rating - Up

It is unlikely that TGVI's rating would be upgraded absent material increases in the company's deemed equity thickness and/or allowed ROE that translated to significant improvements in TGVI's key credit metrics. At the A2, senior unsecured level, Moody's would expect TGVI's ROE to be approximately 11% or more, EBIT/Interest to be approximately 2.5x or more, RCF/Debt to be approximately 8.5% or more, Debt/Book Capitalization (Excluding Goodwill) to be below 60% and FCF/FFO to be approximately 0%.

What Could Change the Rating - Down

Notwithstanding TGVI's relatively low risk business profile, sustained weakening of TGVI's financial metrics resulting from an inability to recover its costs of service, lower deemed equity thickness, lower allowed ROE or other factors could result in a reduction of TGVI's rating. For instance, ROE below 9%, EBIT/Interest below 2.0x, RCF/Debt below 7%, Debt/Book Capitalization (Excluding Goodwill) above 65% and FCF/FFO below -15% would likely cause TGVI's senior unsecured rating to fall to Baa1. If the rates required to allow TGVI to recover its costs of service are uncompetitive with alternative forms of energy on Vancouver Island and TGVI experiences stagnation or loss of customers, TGVI's rating could be negatively impacted.

Rating Factors

Terasen Gas (Vancouver Island) Inc.

Rating Factors and Sub-Factors [1]	**Aaa**	**Aa**	**A**	**Baa**	**Ba**	**B**	**Caa**
Factor 1: Sustainable Profitability (20%)							
a) Return on Equity (15%) [2]			10.7%				
b) EBIT to Customer Base (5%) [3]	$534.3						
Factor 2: Regulatory Support (10%)							
a) Regulatory Support and Relationship		X					
Factor 3: Ring-Fencing (10%)							
a) Ring-Fencing		X					
Factor 4: Financial Strength and Flexibility (60%)							
a) EBIT/Interest (15%)				2.7x			
b) Retained Cash Flow/Debt (15%)				10.2%			
c) Debt to Book Capitalization (Excluding Goodwill) (15%)					66.0%		
d) Free Cash Flow/Funds from Operations (15%)		-11.5%					
Rating:							
a) Methodology Model Implied Senior Unsecured Rating			**A3**				
b) Actual Senior Unsecured Equivalent Rating			**A3**				

[1] Three year averages (2005-2007) [2] Return on Average Equity [3] US$ EBIT/ Residential and Commercial Customers (Excluding Industrials)

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Attachment 86.6.1

Attachment 87.2

Attachment 87.3

Attachment 88.1

Terasen Gas Inc.
Approved Rate Base Deferrals
As at December 31, 2008

Line No.	Particulars	Description	Approval Order #
	(1)	(3)	(4)
1	Deferred Interest	Variations between actual and forecast interest rates and timing of long-term debt issues	G-85-97/G-48-00/G-7-03/G-51-03
2	Deferred Interest - funding benefits via Customer Depos	Variations between unfunded debt interest rate and interest rate on customer security deposits	G-112-04
3	NGV Conversion Grants	program	G-98-99/G-7-03/G-51-03
4	Demand Side Management	Rebates paid related to Demand Side Management programs	G-85-97/G-7-03/G-51-03
5	Property Tax Deferral	Variations between the actual and forecast amount of property taxes	G-51-03
6	Midstream Cost Reconciliation Account (MCRA)	Costs incurred in performing the midstream function and the revenue collected through midstream rates	G-25-04
7	Commodity Cost Reconciliation Account (CCRA)	Costs incurred in purchasing TGI's portion of baseload gas requirements and revenue collected through commodity rates	G-25-04
8	MCRA Interest	Interest on variations between the actual and forecast MCRA balance	G-51-03
9	CCRA Interest	Interest on variations between the actual and forecast CCRA balance	G-51-03
10	Revenue Stabilization Adjustment Mechanism (RSAM)	Variations between the actual and forecast use per customer for Residetial and Commercial customer classes	G-59-94/G-85-97-G-48-00/G-51-03
11	RSAM Interest	Interest on variations between the actual and forecast RSAM balance	G-51-03
12	Revelstoke Propane Cost	Variations between the actual cost of propane and the amount recovered in rates, based on the approved reference price of propane	G-72-90
13	ROE Hearing 2005	Costs incurred related to the 2005 ROE and Capital Structure Hearing	G-132-05

Terasen Gas Inc.

Approved Rate Base Deferrals

As at December 31, 2008

Line No.	Particulars	Description	Approval Order #
	(1)	(3)	(4)
1	Earnings Sharing Mechanism	The customers' 50% share of the pre-tax variations between the approved level of earnings as determined annually and the actual earnings realized	G-51-03
2	NGV Compression Equipment Recovery	The loss on the sale of NGV equipment/stations to 4Pro and the City of Surrey in the year 2000	G-143-99/G-7-03/G-51-03
3	Bad Debt Allowance for Rates 14 & 14A	The difference between 0.3 per cent of the Rate 14A revenues and the actual bad debt experience for Rate 14A	G-64-04
4	SCP Net Mitigation Revenues	Mitigation revenues for the use of SCP transportation capacity that has not been utilized by the firm transportation agreement customers and is sold to others	G-124-00/G-123-01/G-7-03/G-51-03
5	SCP West to East Transmission	Third party revenues related to back-haul movements from Kingsvale to Yahk which relate to transportation service in a West to East direction through the SCP system	G-124-00/G-123-01/G-7-03/G-51-03
6	SCP PG&E Contract Cancellation	Required payments related to the cancellation of the SCP PG&E Contract	G-98-05
7	SCP Tax Reassessment	Provincial sales tax reassessment related to the SCP project, pending resolution of appeal	G-160-06
8	CCT Assessment	This account includes the assessment amounts paid by for Federal Corporate Capital Tax less reimbursements received	G-85-97/G-48-00/G-7-03/G-51-03
9	Pension Variance	Variations between the actual and forecast actuarially-determined pension expenses	G-51-03
10	Insurance Variance	Variations between the actual and forecast insurance expense	G-51-03
11	BCUC Levies	Variations between the actual and approved BCUC levies	G-112-04

Terasen Gas Inc.

Approved Rate Base Deferrals

As at December 31, 2008

Line No.	Particulars	Description	Approval Order #
	(1)	(3)	(4)
1	OSC Certification Compliance	Ongoing costs related to OSC certification compliance M152-109	G-112-04
2	2006 LCT Elimination	Impact of the 2006 elimination of the Large Corporation Capital Tax; offset by the removal of the surtax credit in 2007	G-160-06/G-191-08
3	Terasen Gas Squamish (TGS) O&M Variance	under TGS cost of service and that allowed under the TGI PBR formula (post amalgamation)	G-160-06
4	TGS Amalgamation	Costs incurred to effect the amalgamation of TGI and TGS	G-160-06
5	IFRS Conversion Costs	Costs incurred to convert to International Financial Reporting Standards (IFRS)	G-191-08
6	Deferred Service Line Installation Fee	Amount of the Service Line Installation Fee not recovered from customers for the year 2008 due to changes in the System Extension and Customer Conenction policies	G-153-07/G-191-08
7	Carbon Tax Implementation	One time billing system changes related to the implementation of the Carbon Tax	G-88-08
8	Carbon Tax Cost of Service	Carbon tax associated with compressors and line heaters, offset by the reduced income tax rate in 2008	G-88-08
9	Olympics Security Costs Deferral	Security costs related to the 2010 Olympic and Paralympic games	G-191-08
10	Other Post Employment Benefit Funding (OPEB)	Difference between the amounts funded by ratepayers for OPEB and the amounts actually paid out by TGI	G-135-09/G-7-03/G-51-03

Terasen Gas Inc.
Approved Non-Rate Base Deferrals
As at December 31, 2008

Line No.	Particulars	Description	Approval Order #
	(1)	(3)	(4)
1	Commercial Commodity Unbundling - Capital	Capital costs related to the Commercial Commodity unbundling program	G-25-04/G-57-05
2	Residential Commodity Unbundling - O&M	O&M costs related to the Residential Commodity unbundling program	G-6-06
3	Commercial Commodity Unbundling - O&M	O&M costs related to the Commercial Commodity unbundling program	G-25-04
4	Residential Commodity Unbundling - Capital	Capital costs related to the Residential Commodity unbundling program	G-66-05/G-110-05
5	Lochburn Land Sale	Customers' share of the gain on the sale of the Lochburn land	G-116-07

Attachment 88.2.1

Attachment 88.2.1

	2008			2007			2006			2005			2004		
	Actual	Forecast	Approved	Actual	Forecast	Approved	Actual	Forecast	Approved	Actual	Forecast	Approved	Actual	Forecast	Approved
O&M Not Covered by Deferral	151,558	151,591	164,094	142,867	145,253	158,435	142,232	141,756	155,719	133,791	140,832	152,740	138,331	140,136	153,150
Depreciation & Amortization	74,876	77,722	84,110	75,261	77,602	84,771	80,466	81,048	83,894	76,176	78,664	79,720	77,233	79,079	78,885
Other Revenue (excl $1M SCP)	(20,834)	(20,666)	(22,701)	(21,044)	(20,797)	(23,910)	(21,696)	(22,025)	(23,837)	(22,255)	(23,765)	(24,969)	(19,134)	(22,086)	(21,633)
Income taxes	32,656	32,504	26,760	34,402	35,360	30,897	45,197	43,527	38,977	44,895	42,986	38,321	41,846	42,555	40,218
Short-term interest	11,630	10,459	12,707	5,039	5,501	6,552	6,186	6,751	7,837	6,749	5,857	6,419	7,477	7,584	7,329
Total	249,886	251,610	264,970	236,524	242,919	256,745	252,385	251,057	262,590	239,356	244,574	252,230	245,753	247,268	257,949

Note that the approved amounts are based on a formula so are not indicative of forecast; the forecast has been provided as well.

Attachment 89.1

Attachment 89.1

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OEE Home

- About OEE
- OEE programs
- Grants and incentives
- Publications
- Regulations and standards
- Statistics and analysis
- Awards
- FAQ
- For kids
- Media Room

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Office of Energy Efficiency

Return to sector menu

1990-1995, 1996-2000, 2001-2006

Download

Residential Sector

British Columbia and territories[1]

Table 1: Secondary Energy Use and GHG Emissions by Energy Source

	1990	2001	2002	2003	2004	2005	2006
Total Energy Use (PJ)	**132.1**	**152.5**	**153.2**	**147.4**	**149.1**	**156.0**	**159.0**
Energy Use by Energy Source (PJ)							
Electricity	46.2	59.2	61.0	60.2	64.2	64.5	64.9
Natural Gas	63.9	76.2	79.4	75.4	72.8	79.2	81.8
Heating Oil	11.8	7.4	2.7	2.5	2.9	2.3	2.2
Other[2]	2.9	1.3	1.6	1.4	1.3	1.6	1.3
Wood	7.3	8.3	8.5	8.0	7.9	8.4	8.8
Shares (%)							
Electricity	35.0	38.9	39.8	40.8	43.0	41.3	40.8
Natural Gas	48.4	50.0	51.8	51.1	48.8	50.8	51.5
Heating Oil	8.9	4.8	1.8	1.7	2.0	1.4	1.4
Other[2]	2.2	0.9	1.0	1.0	0.8	1.0	0.8
Wood	5.5	5.4	5.5	5.4	5.3	5.4	5.6
Activity							
Total Floor Space (million m^2)	161	216	220	224	227	232	232
Total Households (thousands)	1,248	1,609	1,631	1,654	1,674	1,708	1,708
Energy Intensity (GJ/m^2)	**0.82**	**0.71**	**0.70**	**0.66**	**0.66**	**0.67**	**0.68**
Energy Intensity (GJ/household)	105.8	94.8	93.9	89.1	89.1	91.4	93.1
Total GHG Emissions Excluding Electricity (Mt of CO2e)	**4.4**	**4.6**	**4.4**	**4.2**	**4.1**	**4.4**	**4.5**
GHG Emissions by Energy Source (Mt of CO2e)							
Electricity	–	–	–	–	–	–	–
Natural Gas	3.2	3.8	4.0	3.8	3.6	3.9	4.1

Heating Oil	0.9		0.5	0.2	0.2	0.2	0.2	0.2
Other[2]	0.2		0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1		0.2	0.2	0.1	0.1	0.2	0.2
Shares (%)								
Electricity	–		–	–	–	–	–	–
Natural Gas	73.4		83.2	89.9	90.1	89.3	90.2	91.0
Heating Oil	19.5		11.7	4.4	4.3	5.2	3.7	3.5
Other[1]	4.0		1.8	2.2	2.1	1.9	2.5	1.9
Wood	3.1		3.3	3.5	3.5	3.6	3.6	3.6
GHG Intensity (tonne/TJ)	**33.2**		**30.0**	**28.8**	**28.3**	**27.2**	**28.0**	**28.2**
Heating Degree-Day Index	**0.97**		**0.95**	**0.95**	**0.87**	**0.85**	**0.89**	**0.91**
Cooling Degree-Day Index	0.71		0.66	1.55	2.37	3.49	1.59	1.62

Footnotes:
1) Data on GHG emissions are presented excluding GHG emissions related to electricity production only.
2) “Other” includes coal and propane.

Return to sector menu

Download

1990-1995, 1996-2000, 2001-2006

Office of Energy Efficiency (OEE)
OEE Home
- About OEE
- OEE programs
- Grants and incentives
- Publications
- Regulations and standards
- Statistics and analysis
- Awards
- FAQ
- For kids
- Media Room

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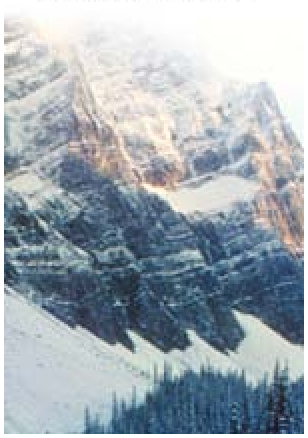

Office of Energy Efficiency

Return to sector menu

1990-1995, 1996-2000, 2001-2006

Download

Commercial/Institutional Sector
British Columbia and Territories[1]
Table 1: Secondary Energy Use and GHG Emissions by Energy Source

	1990	2001	2002	2003	2004	2005	2006
Total Energy Use (PJ)	**100.6**	**123.3**	**135.0**	**121.1**	**119.0**	**117.4**	**117.7**
Energy Use by Energy Source (PJ)							
Electricity	42.4	53.3	53.1	52.2	50.1	50.9	51.7
Natural Gas	47.5	61.9	70.0	57.2	55.3	54.3	54.8
Light Fuel Oil and Kerosene	7.9	3.1	7.4	7.6	7.9	7.6	6.8
Heavy Fuel Oil	0.8	1.0	0.8	0.7	2.6	2.6	2.4
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other[2]	1.9	4.0	3.8	3.4	3.1	2.1	2.1
Shares (%)							
Electricity	42.2	43.2	39.3	43.1	42.1	43.3	43.9
Natural Gas	47.3	50.2	51.8	47.3	46.5	46.2	46.5
Light Fuel Oil and Kerosene	7.9	2.5	5.5	6.3	6.6	6.5	5.8
Heavy Fuel Oil	0.8	0.8	0.6	0.5	2.2	2.2	2.0
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other[2]	1.9	3.3	2.8	2.8	2.6	1.8	1.8
Total Floor Space (million m^2)	**59.6**	**81.1**	**83.4**	**85.6**	**88.0**	**90.0**	**93.1**
Energy Intensity[3] (GJ/m^2)	**1.67**	**1.51**	**1.61**	**1.41**	**1.34**	**1.30**	**1.26**
Total GHG Emissions Excluding Electricity (Mt of CO2e)	**3.1**	**3.6**	**4.3**	**3.7**	**3.7**	**3.6**	**3.5**
GHG Emissions by Energy Source (Mt of CO2*e*)							
Electricity	–	–	–	–	–	–	–
Natural Gas	2.4	3.1	3.5	2.9	2.8	2.7	2.7
Light Fuel Oil and Kerosene	0.6	0.2	0.5	0.5	0.6	0.6	0.5

Heavy Fuel Oil	0.1		0.1	0.1	0.0	0.2	0.2	0.2
Steam	0.0		0.0	0.0	0.0	0.0	0.0	0.0
Other[2]	0.1		0.3	0.2	0.2	0.2	0.1	0.1
GHG Intensity (tonne/TJ)	**31.2**		**29.5**	**32.0**	**30.2**	**31.1**	**30.3**	**29.9**
Heating Degree-Day Index	**0.97**		**0.95**	**0.95**	**0.87**	**0.85**	**0.89**	**0.91**
Cooling Degree-Day Index	0.71		0.66	1.55	2.37	3.49	1.59	1.62

Footnotes:
1) Data on GHG emissions are presented excluding GHG emissions related to electricity production.
2) “Other” includes coal and propane.
3) Excludes street lighting.

Return to sector menu

Download

1990-1995, 1996-2000, 2001-2006

Office of Energy Efficiency

Return to sector menu

1990-1995, 1996-2000, 2001-2006

Download

Industrial Sector – Aggregated Industries
British Columbia and Territories[1]
Table 1: Secondary Energy Use and GHG Emissions by Energy Source

	1990	2001	2002	2003	2004	2005	2006
Total Energy Use (PJ)	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Energy Use by Energy Source (PJ)							
Electricity	99.4	100.7	100.3	103.9	108.7	111.5	108.0
Natural Gas	82.6	119.4	107.2	104.5	104.7	100.2	90.3
Diesel Fuel Oil, Light Fuel Oil and Kerosene	X	X	X	X	X	X	X
Heavy Fuel Oil	X	X	X	X	X	X	X
Still Gas and Petroleum Coke	X	X	X	X	X	X	X
LPG and Gas Plant NGL	X	X	X	X	X	X	X
Coal	8.7	X	X	18.5	21.7	13.4	10.2
Coke and Coke Oven Gas	1.1	0.2	0.2	0.2	0.2	0.2	0.2
Wood Waste and Pulping Liquor	141.1	162.0	160.7	159.5	164.6	180.0	193.6
Other[2]	0.0	2.7	0.2	0.3	2.0	2.0	1.8
Shares (%)							
Electricity	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Natural Gas	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Diesel Fuel Oil, Light Fuel Oil and Kerosene	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Heavy Fuel Oil	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Still Gas and Petroleum Coke	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
LPG and Gas Plant NGL	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Coal	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Coke and Coke Oven Gas	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wood Waste and Pulping Liquor	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Other[2]	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
GDP (million $97)	**23,459**	**26,935**	**26,547**	**27,855**	**30,382**	**31,583**	**32,987**

Energy Intensity (MJ / $97 – GDP)	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**
Total GHG Emissions Excluding Electricity (Mt of CO2e)	**X**	**X**	**X**	**X**	**X**	**X**	**X**
GHG Emissions by Energy Source (Mt of CO2*e*)							
Electricity	–	–	–	–	–	–	–
Natural Gas	4.2	6.0	5.4	5.2	5.2	5.0	4.5
Diesel Fuel Oil, Light Fuel Oil and Kerosene	X	X	X	X	X	X	X
Heavy Fuel Oil	X	X	X	X	X	X	X
Still Gas and Petroleum Coke	X	X	X	X	X	X	X
LPG and Gas Plant NGL	X	X	X	X	X	X	X
Coal	0.5	X	X	1.5	1.7	1.0	0.8
Coke and Coke Oven Gas	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste and Pulping Liquor	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shares (%)							
Electricity	–	–	–	–	–	–	–
Natural Gas	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Diesel Fuel Oil, Light Fuel Oil and Kerosene	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Heavy Fuel Oil	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Still Gas and Petroleum Coke	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
LPG and Gas Plant NGL	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Coal	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Coke and Coke Oven Gas	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wood Waste and Pulping Liquor	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Other[2]	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
GHG Intensity (tonne / TJ)	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**

Footnotes:

1) Data on GHG emissions are presented excluding GHG emissions related to electricity production.

2) "Other" includes steam and waste fuels from the cement industry.

Return to sector menu

Download

1990-1995, 1996-2000, 2001-2006

X - Denotes data that has been suppressed due to confidentiality.
n.a. - Denotes data that is not available.

Office of Energy Efficiency (OEE)

OEE Home
- About OEE
- OEE programs
- Grants and incentives
- Publications
- Regulations and standards
- Statistics and analysis
- Awards
- FAQ
- For kids
- Media Room

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Office of Energy Efficiency

Return to sector menu

1990-1995, 1996-2000, 2001-2006

Download

Transportation Sector
British Columbia and Territories
Table 1: Secondary Energy Use by Energy Source

	1990	2001	2002	2003	2004	2005	2006
Total Energy Use (PJ)	**268.2**	**342.6**	**346.3**	**356.0**	**376.9**	**365.8**	**359.3**
Passenger Transportation	151.9	182.8	187.3	182.7	192.0	183.1	183.0
Freight Transportation	109.7	146.9	146.0	160.1	171.1	168.5	162.1
Off-Road[1]	6.6	12.9	13.0	13.2	13.8	14.1	14.2
Energy Use by Energy Source (PJ)							
Electricity	0.3	0.4	0.5	0.5	0.5	0.5	0.4
Natural Gas	0.9	0.3	0.2	0.2	0.2	0.2	0.2
Motor Gasoline	124.9	158.8	157.6	160.5	169.9	160.9	158.6
Diesel Fuel Oil	74.9	92.0	94.5	95.4	103.4	103.8	101.5
Light Fuel Oil and Kerosene	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Fuel Oil	16.6	29.8	26.6	38.1	38.1	37.0	35.0
Aviation Gasoline	1.5	0.8	0.7	0.6	0.6	0.6	0.6
Aviation Turbo Fuel	36.9	55.5	61.5	56.5	60.0	59.6	60.0
Propane	12.3	5.0	4.6	4.2	4.2	3.1	3.1
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shares (%)							
Electricity	0.1	0.1	0.2	0.2	0.1	0.1	0.1
Natural Gas	0.3	0.1	0.0	0.0	0.0	0.0	0.0
Motor Gasoline	46.6	46.3	45.5	45.1	45.1	44.0	44.1
Diesel Fuel Oil	27.9	26.9	27.3	26.8	27.4	28.4	28.2
Light Fuel Oil and Kerosene	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Fuel Oil	6.2	8.7	7.7	10.7	10.1	10.1	9.7
Aviation Gasoline	0.5	0.2	0.2	0.2	0.2	0.2	0.2
Aviation Turbo Fuel	13.8	16.2	17.8	15.9	15.9	16.3	16.7
Propane	4.6	1.5	1.3	1.2	1.1	0.8	0.9
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Footnotes:

1) “Off Road” includes vehicles not registered for on-road travel such as ATVs, snowmobiles, golf carts and some military vehicles.

Return to sector menu

Download

1990-1995, 1996-2000, 2001-2006

Office of Energy Efficiency (OEE)

OEE Home
- About OEE
- OEE programs
- Grants and incentives
- Publications
- Regulations and standards
- Statistics and analysis
- Awards
- FAQ
- For kids
- Media Room

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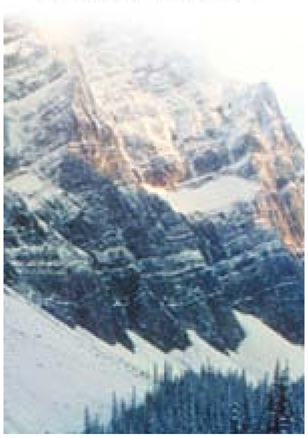

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Return to sector menu

1990-1995, 1996-2000, 2001-2006

Download

Agriculture Sector
British Columbia and Territories[1]
Table 11: Secondary Energy Use and GHG Emissions by End-Use and Energy Source – **Excluding** Electricity-Related Emissions

	1990	2001	2002	2003	2004	2005	2006
Total Energy Use (PJ)	**10.1**	**19.0**	**15.3**	**14.4**	**13.9**	**11.7**	**11.8**
Energy Use by End-Use (PJ)							
Non-Motive Energy Use	6.1	8.1	3.8	3.0	2.6	2.5	2.4
Motive Energy Use[2]	4.0	10.9	11.5	11.4	11.3	9.1	9.5
Energy Use by Energy Source (PJ)							
Electricity	1.0	1.4	1.3	1.3	1.5	1.5	1.3
Natural Gas	2.8	4.1	0.7	0.7	0.7	0.7	0.8
Motor Gasoline	2.2	3.3	4.1	4.2	4.2	3.8	3.8
Diesel Fuel Oil	1.8	7.6	7.4	7.2	7.1	5.3	5.6
Light Fuel Oil	1.5	2.0	1.3	0.8	0.3	0.1	0.1
Kerosene	0.4	0.2	0.2	0.1	0.1	0.0	0.0
Heavy Fuel Oil	0.0	0.1	0.1	0.0	0.0	0.0	0.0
Propane	0.5	0.3	0.2	0.2	0.2	0.1	0.1
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shares (%)							
Electricity	9.7	7.6	8.8	9.0	10.4	12.6	11.2
Natural Gas	27.4	21.8	4.8	4.8	4.8	6.4	6.3
Motor Gasoline	21.8	17.4	26.9	28.8	30.1	32.9	32.2
Diesel Fuel Oil	17.7	40.1	48.4	50.2	50.9	45.5	47.7
Light Fuel Oil	15.1	10.3	8.5	5.4	2.2	1.1	1.2
Kerosene	3.7	1.0	1.1	0.7	0.5	0.3	0.1
Heavy Fuel Oil	0.0	0.4	0.4	0.0	0.0	0.0	0.0
Propane	4.6	1.4	1.1	1.1	1.1	1.2	1.2
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0

GDP (million $97)	**1,072**	**1,207**	**1,235**	**1,245**	**1,226**	**1,217**	**1,154**
Energy Intensity (MJ/$97 – GDP)	**9.5**	**15.7**	**12.4**	**11.6**	**11.3**	**9.6**	**10.3**
Total GHG Emissions Excluding Electricity (Mt of CO2e)	**0.6**	**1.2**	**1.0**	**1.0**	**0.9**	**0.7**	**0.8**
GHG Emissions by End-Use (Mt of CO2e)							
Non-Motive GHG Emissions	0.3	0.4	0.2	0.1	0.1	0.1	0.1
Motive GHG Emissions[2]	0.3	0.8	0.9	0.8	0.8	0.7	0.7
GHG Emissions by Energy Source (Mt of CO2e)							
Electricity	–	–	–	–	–	–	–
Natural Gas	0.1	0.2	0.0	0.0	0.0	0.0	0.0
Motor Gasoline	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Diesel Fuel Oil	0.1	0.6	0.6	0.6	0.6	0.4	0.4
Light Fuel Oil	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Kerosene	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shares (%)							
Electricity	–	–	–	–	–	–	–
Natural Gas	23.5	17.2	3.6	3.6	3.7	5.0	4.9
Motor Gasoline	25.3	18.5	27.3	29.3	31.1	35.3	33.9
Diesel Fuel Oil	23.4	49.7	57.2	59.4	61.3	56.9	58.5
Light Fuel Oil	18.9	11.9	9.4	6.0	2.4	1.2	1.4
Kerosene	4.3	1.0	1.1	0.7	0.5	0.3	0.1
Heavy Fuel Oil	0.0	0.5	0.5	0.0	0.0	0.0	0.0
Propane	4.7	1.3	1.0	1.0	1.0	1.2	1.2
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GHG Intensity (tonne/TJ)	**58.8**	**63.5**	**66.5**	**66.4**	**65.3**	**62.8**	**64.0**

Footnotes:

1) At the regional level, data on GHG emissions are presented excluding GHG emissions related to electricity production only.

2) "Motive" includes motor gasoline and diesel fuel oil. All other energy sources are included in non-motive.

Return to sector menu

Download

1990-1995, 1996-2000, 2001-2006