Terasen Gas

Scott A. Thomson
VP, Finance & Regulatory Affairs and
Chief Financial Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7784
Fax: (604) 592-7890
Email: scott.thomson@terasengas.com
www.terasengas.com

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

October 16, 2006

British Columbia Utilities Commission
6th Floor - 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sir:

RE: Terasen Gas Inc.
2004 – 2007 Performance Based Rate Plan
2006 Annual Review and Mid-Term Assessment Review – November 15, 2006
BCUC Order No. G-121-06

By Order No. G-121-06, the British Columbia Utilities Commission ("the Commission") set November 15, 2006 as the date for the 2006 Terasen Gas Inc. Annual Review and Mid-Term Assessment Review. This Annual Review will be the fourth under the Company's 2004 – 2007 Multi-Year Performance Based Rate settlement agreement ("the Settlement"). The Settlement was approved by Commission Order No. G-51-03 dated July 29, 2003. The Commission's approval of the Settlement followed a public hearing and Commission Decision on the Company's 2003 Revenue Requirement Application, an April 17, 2003 Application for a Multi-Year Performance Based Rate Plan for 2004-2008, information requests and responses and a negotiated settlement process in June and July 2003.

The terms of the Settlement require Terasen Gas to submit to the Commission and interested parties advance materials, including materials on the Mid-Term Assessment Review in 2006, on the information to be presented at the Annual Review three weeks prior to the Annual Review. The details of the Annual Review process are set out on Pages 17 to 22 of Appendix A of Commission Order No. G-51-03.

The 2006 Annual Review and Mid-Term Assessment Review is a process for the Company and stakeholders to ensure that the objectives of the Settlement are being achieved, to conduct a mid-term assessment review to assess the effectiveness of the PBR settlement, and to review the cost drivers and financial forecasts for the purposes of establishing the 2007 revenue requirements.

Enclosed are twenty (20) copies of the advance information for the 2006 Annual Review. Section A of the binder includes information on the cost drivers, and financial projections and forecasts necessary for setting 2007 delivery rates. Section B of the binder includes various other reports and information requirements identified in the Settlement and Commission Order No. G-51-03. Terasen Gas will present information at the Annual Review on the matters addressed in the advance materials.

Terasen Gas (Squamish) Inc. and the Province of B.C. have been involved in negotiations in an effort to reach a resolution of certain financial obligations as between those two parties. Over the course of the late summer and early fall, TGS and the Province were able to agree on a process to resolve these obligations. As part of the resolution of the financial obligations, TGS will be amalgamating with TGI effective January 1, 2007. Accordingly, the 2007 Terasen Gas Inc. revenue requirement has been prepared on an amalgamated basis effective January 1, 2007**.** Section B, Tab 6 provides additional information, including financial schedules, regarding the amalgamation.

The amalgamated 2007 revenue requirement decrease identified in the enclosed materials is $4.1 million, equivalent to a 0.8% decrease in gross margin or a 0.3% decrease in total revenue at existing rates. After taking into consideration the earnings surplus incentive sharing, the decrease is $16.8 million, equivalent to a 3.4% decrease in gross margin, or a 1.2% decrease in total revenue at existing rates.

Contributors to cost pressures in 2007 include higher property taxes of $3.0 million, higher operating and maintenance expenses of $1.5 million, higher depreciation and amortization expense of $0.6 million and higher interest expense of $2.0 million. Mitigating the cost pressures are lower income taxes due to the elimination of the Large Corporations Tax, higher income tax deductions, lower rate base due to lower gas in storage values and additional revenues from customer growth. When the effects of the projected changes to the RSAM, Earnings Sharing Mechanism, and the ROE 06Q1 Revenue Shortfall riders are factored in, residential customers can expect a decrease of 0.70% at the burnertip. A summary of the contributors to the decrease are summarized in Tab A-1, Page 4.

The revenue requirement information included is based on TGI's allowed 2006 return on equity ("ROE") at 8.80% plus the effect of the anticipated amalgamation of Squamish to yield an 8.80141% ROE on an amalgamated basis. There is also a one time change in the capital structure due to the amalgamation. The common equity component of the amalgamated entity will move from 35% (as it is now for TGI) to a weighted average of TGI and TGS which will be 35.01238% for 2007. Variances from the allowed ROE level compared to the ROE as determined in accordance with the Commission's March 2, 2006 ROE Decision will result in corresponding changes to the final 2007 revenue requirement. Any rate changes related to the flow-through of gas cost changes will be dealt with in a separate application to the Commission.

We trust the enclosed is satisfactory. To assist in the planning of the review, it would be appreciated if any party that intends to attend the Annual Review on November 15, 2006 would contact Regulatory Affairs by email at regulatory.affairs@terasengas.com or by phone (604) 592-7664 to advise of the intended attendance.

Yours very truly,

TERASEN GAS INC.

Original signed

Scott Thomson

c. 2004 – 2007 PBR NSP Participants

TERASEN GAS INC.

2006 ANNUAL REVIEW
2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

REVISED FORECASTS AND PROJECTIONS FOR 2007 REVENUE REQUIREMENTS AND OTHER INFORMATION PERTAINING TO THE SETTLEMENT

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SECTION A-1 INDEX

SUMMARY OF REVENUE REQUIREMENTS FOR THE YEAR ENDING DECEMBER 31, 2007

By Order No. G-51-03 dated July 29, 2003, the British Columbia Utilities Commission ("BCUC" or the "Commission") approved the Negotiated Settlement of the Terasen Gas Inc. ("Terasen Gas") Multi-Year Performance Based Rate Plan for 2004 – 2007 (the "Settlement" or "PBR").

Pursuant to the provisions of the Settlement Agreement, Terasen Gas has developed the projections and forecasts needed to establish the 2007 revenue requirement. The attached costs and revenues incorporate updated data for:

- 2006 projected year-end customers,
- 2006 projected formula-based capital expenditures trued up for customer additions and average total customers, the resulting year-end plant balances, and other rate base information,
- 2006 projected deferral account balances and amortization,
- 2006 projected formula-based utility O&M trued up for average total customers,
- Other projected 2006 cost-of-service items required under the terms of the Settlement for setting 2007 rates,
- 2007 forecast cost drivers, such as customer additions, average total customers and inflation (less an adjustment factor),
- 2007 customer use rate forecasts,
- 2007 forecast volumes and revenues,
- 2007 formula-based utility O&M expenses including adjustments, as per the terms of the Settlement, for the change in forecast pension and insurance costs,
- 2007 formula-based base capital expenditures and resulting plant balances, accumulated depreciation and contributions-in-aid-of-construction,
- 2007 forecast property taxes,
- 2007 forecast working capital, deferred account balances and amortization, and
- 2007 forecast long-term debt and the associated financing costs of long-term and unfunded debt to be included in 2007 rates.

Terasen Gas (Squamish) Inc. and the Province of B.C. have been involved in negotiations in an effort to reach a resolution of certain financial obligations as between those two parties. Over the course of the late summer and early fall, TGS and the Province were able to agree on a process to resolve these obligations. As part of the resolution of the financial obligations, TGS will be amalgamating with TGI effective January 1, 2007. Accordingly, TGS data has been included in the calculation of the Terasen Gas 2007 revenue requirement and the preparation of the schedules in Section A Tabs 1 though 7 of this filing.

A summary of the amalgamated 2007 revenue requirement decrease determined pursuant to the terms of the Settlement Agreement and the Revised Target is shown on the following financial summary pages:

Page 5 Summary of Rate Change Required
Page 6 Utility Rate Base
Page 7 Utility Income and Earned Return
Page 8 Income Taxes / Revenue Surplus
Page 9 Return on Capital

The 2007 test year costs and revenues are explained under the following section of this Annual Review material:

- TGI Amalgamated
  - Cost Drivers - see Section A, Tab 2,
  - Gas plant in service, plant additions and other rate base components - see Section A, Tab 3,
  - Volumes and revenues - see Section A, Tab 4,
  - Operating and maintenance costs - see Section A, Tab 5,
  - Taxes and other expenses - see Section A, Tab 6,
  - Financing costs - see Section A, Tab 7,
- Terasen Gas (Squamish) Inc. (Stand Alone) - see Section A, Tab 8,
- Terasen Gas Inc. (Stand Alone) Summary Schedules- see Section A, Tab 9, and
- TGI 2006 Projected Results - see Section A, Tab 10.

The results of incorporating the forecast and formula-based costs and revenues in the 2007 test year show that the revenue requirement decrease, before the earnings surplus sharing, is $4.1 million, equivalent to a 0.8% decrease in gross margin, or a 0.3% decrease in total revenue at existing rates. After taking into consideration the earnings surplus incentive sharing, the decrease is $16.8 million, equivalent to a 3.4% decrease in gross margin, or a 1.2% decrease in total revenue at existing rates.

The decrease to rate base as a result of a reduction in gas in storage and other values contributed $3.3 million to the $4.1 million revenue requirement decrease. Other contributors to the revenue requirement decrease include the elimination of the Large Corporations Tax which reduces the revenue requirement by $4.7 million, increase gross margin of $2.1 million as a result of customer growth, higher income tax deductions contributed $1.0 million and a decrease in the pension and insurance forecast of $2.7 million. Contributors to cost pressures include higher property taxes, interest expense, depreciation and amortization and operating and maintenance expenses. A summary of the components of the revenue requirement decrease is shown on Page 4.

In addition to the delivery rate changes arising from the $4.1 million revenue requirement decrease, core market customers will also experience rate changes in 2007 related to the Revenue Stabilization Adjustment Mechanism (RSAM) rider which is expected to decrease from the 2006 level by $0.020 per gigajoule. Further, core market customers will experience a decrease in the revenue requirement of an average of $0.096 per gigajoule resulting from the earnings sharing surplus as determined in accordance with the earnings sharing mechanism as well as a decrease resulting from the expiration of the ROE 06Q1 Revenue Shortfall Rider of $0.010 per gigajoule. There may also be flow-through of cost of gas changes as cost of gas is dependent on the commodity market which is subject to considerable volatility. A cold weather snap or unexpected negative news can change the natural gas commodity market outlook quite quickly. Overall, residential customers can expect to see a decrease of 0.70% to the annual bill when all of the changes related to the RSAM rider, the allowed return on common equity (“ROE”) 06Q1 Revenue Shortfall Rider, the delivery rate and the earnings sharing credit are factored in.

The final rates for 2007 may be subject to further adjustments for changes in the ROE. The financial calculations for 2007 in the enclosed materials have been made using an ROE of 8.80% representing the allowed TGI 2006 ROE, plus the effects of the anticipated amalgamation of Squamish to yield an 8.80141% ROE on an amalgamated basis. In addition, the common equity component has changed from 35.0% to 35.01238%, on an amalgamated basis. Variances from the allowed ROE level compared to the ROE as determined in accordance with the Commission’s March 2, 2006 ROE Decision will result in corresponding changes to the final 2007 revenue requirement.

SUMMARY OF 2007 REVENUE REQUIREMENT DECREASE

		($ Millions)
Volumes/Revenue Related		
Customer Growth		$ (2.1)
O & M Related		
Higher O&M per formula	$ 4.2	
Change in Pension and Insurance forecast	(2.7)	1.5
Other Items		
Higher Property Taxes	3.0	
Higher Depreciation and Amortization	0.6	
Higher Interest Expense	2.0	
Elimination of Large Corporations Tax	(4.7)	
Higher Income Tax Deductions	(1.0)	
Lower Rate Base and Others	(3.3)	(3.4)
TGI Revenue Decrease		(4.0)
TGS Revenue Decrease		(0.1)
Total Revenue Decrease (Section A, Tab 1, Page 5, Column 6, Line 15)		(4.1)
Earnings Sharing		(12.7)
Net Revenue Decrease after Earnings Sharing		$ (16.8)

TERASEN GAS INC.

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Core	2007 Non-Core	2007 Bypass and Special Rates	2007 Total	Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RATE CHANGE REQUIRED						
2							
3	Gas Sales and Transportation Revenue,						
4	At Prior Year's Rates	$1,626,467	$1,389,582	$61,764	$13,835	$1,465,181	($161,286)
5							
6	Add - Other Revenue Related to SCP Third Party						
7	Revenue / Terasen Gas (Vancouver Island)	15,159	0	0	15,173	15,173	14
8							
9	Total Revenue	1,641,626	1,389,582	61,764	29,008	1,480,354	(161,272)
10							
11	Less - Cost of Gas	(1,151,571)	(964,375)	(1,355)	(1,150)	(966,880)	184,691
12							
13	Gross Margin	$490,055	$425,207	$60,409	$27,858	$513,474	$23,419
14							
15	Revenue Deficiency (Surplus)	$19,776	($3,615)	($514)	$0	($4,129)	
16							
17	Revenue Deficiency (Surplus) as a % of Gross Margin	4.04%	-0.85%	-0.85%	0.00%	-0.80%	
18							
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.20%	-0.26%	-0.83%	0.00%	-0.28%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 Adjustments	2007 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$3,067,485	$3,140,710	$0	$3,140,710	$73,225	- Tab A-3, Page 8.1
2	CPCNs	4,564	8,137	0	8,137	3,573	- Tab A-3, Page 8.1
3							
4	Additions	125,924	129,717	0	129,717	3,793	- Tab A-3, Page 8.1
5	Disposals	(56,345)	(32,918)	0	(32,918)	23,427	- Tab A-3, Page 8.1
6							
7	Plant in Service, Ending	3,141,628	3,245,646	0	3,245,646	104,018	
8							
9	Add - Intangible Plant	837	1,614	0	1,614	777	
10							
11		3,142,465	3,247,260	0	3,247,260	104,795	
12							
13	Contributions In Aid of Construction	(137,019)	(131,162)	0	(131,162)	5,857	- Tab A-3, Page 9
14							
15	Less - Accumulated Depreciation	(671,378)	(744,227)	0	(744,227)	(72,849)	- Tab A-3, Page 15
16							
17							
18	Net Plant in Service, Ending	$2,334,068	$2,371,871	$0	$2,371,871	$37,803	
19							
20							
21	Net Plant in Service, Beginning	$2,302,480	$2,339,687	$0	$2,339,687	$37,207	- Tab A-3, Page 10
22							
23							
24	Net Plant in Service, Mid-Year	$2,318,274	$2,355,779	$0	$2,355,779	$37,505	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(11)	(11)	0	(11)	0	
27	Work in Progress, No AFUDC	11,902	10,771	0	10,771	(1,131)	
28	Unamortized Deferred Charges	13,109	(8,227)	0	(8,227)	(21,336)	- Tab A-3, Page 13.1
29	Cash Working Capital	(29,050)	(25,214)	17	(25,197)	3,853	- Tab A-3, Page 14
30	Other Working Capital	194,361	143,982	0	143,982	(50,379)	- Tab A-3, Page 14
31	Deferred Income Tax, Mid-Year	(364)	(606)	0	(606)	(242)	
32	LILO Benefit	(2,312)	(2,243)	0	(2,243)	69	
33	Utility Rate Base	$2,505,909	$2,474,231	$17	$2,474,248	($31,661)	

TERASEN GAS INC.

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 ----Revised Rates----- Revised Revenue	2007 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	116,140	116,776	0	116,776	636	- Tab A-4, Page 14
3	Transportation	98,287	95,397	0	95,397	(2,890)	- Tab A-4, Page 14
4		214,427	212,173	0	212,173	(2,254)	
5							
6	Average Rate per GJ						
7	Sales	$13.539	$11.904	$0.000	$11.873	($1.666)	
8	Transportation	$0.751	$0.787	$0.000	$0.782	$0.031	
9	Average	$7.677	$6.906	$0.000	$6.886	($0.791)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,555,107	$1,390,101	$0	$1,390,101	($165,006)	- Tab A-4, Page 15
13	- Increase / (Decrease)	17,318	0	(3,617)	(3,617)	(20,935)	
14							
15	Transportation - Existing Rates	71,360	75,080	0	75,080	3,720	- Tab A-4, Page 15
16	- Increase / (Decrease)	2,458		(512)	(512)	(2,970)	
17	Total	1,646,243	1,465,181	(4,129)	1,461,052	(185,190)	
18							
19	Cost of Gas Sold (Including Gas Lost)	1,151,571	966,880	0	966,880	(184,691)	- Tab A-4, Page 16.1
20							
21	Gross Margin	494,672	498,301	(4,129)	494,172	(499)	
22							
23	Operation and Maintenance	167,091	169,272	0	169,272	2,181	- Tab A-5, Page 2
24	Vehicle Lease	1,804	1,993	0	1,993	189	
25	Property and Sundry Taxes	41,379	44,452	0	44,452	3,073	- Tab A-6, Page 4
26	Depreciation and Amortization	83,894	84,701	0	84,701	807	- Tab A-6, Page 7
27	Other Operating Revenue	(24,837)	(24,910)	0	(24,910)	(73)	- Tab A-4, Page 18
28		269,331	275,508	0	275,508	6,177	
29	Utility Income Before Income Taxes	225,341	222,793	(4,129)	218,664	(6,677)	
30							
31	Income Taxes	38,977	34,068	(1,362)	32,706	(6,271)	- Tab A-1, Page 8
32							
33	EARNED RETURN	$186,364	$188,725	($2,767)	$185,958	($406)	- Tab A-1, Page 9
34							
35	UTILITY RATE BASE	$2,505,909	$2,474,231	$17	$2,474,248	($31,661)	- Tab A-1, Page 6
36							
37	RATE OF RETURN ON UTILITY RATE BASE	7.437%	7.628%		7.516%	0.079%	

TERASEN GAS INC.

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 ----Revised Rates----- Revised Revenue	2007 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$186,364	$188,725	($2,767)	$185,958	($406)	- Tab A-1, Page 9
3	Deduct - Interest on Debt	(109,168)	(109,712)	0	(109,712)	(544)	
4	Add- Non-Tax Ded. Expense (Net)	(1,348)	(2,290)	0	(2,290)	(942)	- Tab A-6, Page 6
5							
6	Accounting Income After Tax	75,848	76,723	(2,767)	73,956	(1,892)	
7	Add (Deduct) - Timing Differences	(6,115)	(7,553)	0	(7,553)	(1,438)	- Tab A-6, Page 6
8	Add - Large Corporation Tax	1,885	0	0	0	(1,885)	
9							
10	Taxable Income After Tax	$71,618	$69,170	($2,767)	$66,403	($5,215)	
11							
12	Income Tax Rate (Current Tax)	34.120%	33.000%	33.000%	33.000%	-1.120%	
13	1 - Current Income Tax Rate	65.880%	67.000%	67.000%	67.000%	1.120%	
14							
15	Taxable Income (L10 / L13)	$108,710	$103,238	($4,129)	$99,109	($9,601)	
16							
17	Income Tax - Current (L12 x L15)	$37,092	$34,068	($1,362)	$32,706	($4,386)	
18							
19	- Large Corporation Tax	1,885	0	0	0	(1,885)	
20							
21	Total	$38,977	$34,068	($1,362)	$32,706	($6,271)	- Tab A-1, Page 7
22							
23							
24	REVENUE DEFICIENCY						
25	Earned Return	$186,364		($2,767)	$185,958	($406)	- Tab A-1, Page 7
26	Add - Income Taxes	38,977		(1,362)	32,706	(6,271)	- Tab A-1, Page 7
27	Deduct - Utility Income Before Taxes,						
28	Existing Rates	(205,565)		0	(222,793)	(17,228)	- Tab A-1, Page 7
29	Corporate Capital Tax	0		0	0	0	
30							
31	Deficiency/(Surplus) After Corporate Capital Tax	$19,776		($4,129)	($4,129)	($23,905)	

TERASEN GAS INC.

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2007 AT 2006 RATES							
2	Long-Term Debt			$1,470,051	59.42%	7.018%	4.170%	
3	Unfunded Debt			137,892	5.57%	4.750%	0.265%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			866,288	35.01%	9.120%	3.193%	
6								
7				$2,474,231	100.00%		7.628%	
8								
9	2007 REVISED RATES							
10	Long-Term Debt			$1,470,051	59.42%	7.018%	4.170%	$103,162
11	Unfunded Debt		$137,892					
12	Adjustment, Revised Rates		12	137,904	5.57%	4.750%	0.265%	6,550
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			866,293	35.01238%	8.80141%	3.082%	76,246
15								
16				$2,474,248	100.00%		7.516%	$185,958
17								
18	2006 APPROVED RATES							
19	Long-Term Debt			$1,432,919	57.18%	7.072%	4.044%	$101,331
20	Unfunded Debt		$195,980					
21	Adjustment, Revised Rates		(58)	195,922	7.82%	4.000%	0.313%	7,837
22	Preference Shares			0	0.00%	0.000%	0.000%	0
23	Common Equity			877,068	35.00%	8.800%	3.080%	77,182
24								
25				$2,505,909	100.00%		7.437%	$186,350
26								
27	CHANGE FROM 2006 APPROVED							
28	Long-Term Debt			$37,132	2.24%	-0.054%	0.126%	$1,831
29	Unfunded Debt		($58,088)					
30	Adjustment, Revised Rates		70	(58,018)	-2.25%	0.750%	-0.048%	(1,287)
31	Preference Shares			0	0.00%	0.000%	0.000%	0
32	Common Equity			(10,775)	0.01%	0.001%	0.002%	(936)
33								
34				($31,661)	0.00%		0.080%	($392)

TERASEN GAS INC.

2006 ANNUAL REVIEW
2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

REVISED FORECASTS AND PROJECTIONS FOR 2007 REVENUE REQUIREMENTS AND OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-2 INDEX

2007 COST DRIVERS

The table below shows the Cost Driver forecasts which are used for setting the 2007 Targets as prescribed in BCUC Order No. G-51-03. 2007 Forecast customer counts are inclusive of customers from the former TGS.

	2005 Actual	2006 Projected	2007 Forecast	
Cost Drivers				
Year End Customer Counts	799,365	812,091	828,700	Note 1
Customer Additions		12,726	13,385	Note 2
Average Customers Counts	791,593	803,686	820,347	Note 3
Change in Average Customers		12,093	13,587	Note 2
Percentage of Customer Growth - Average		1.53%	1.69%	
Escalators				
B.C. Inflation (CPI)			2.0%	Note 4
Adjustment Factor - % of CPI			66%	Note 5
Adjustment Factor			-1.32%	

Explanatory Notes

Note 1 2006 projection and 2007 forecast year end customer counts are explained under Tab 4 – Gas Sales and Transportation Volumes. Year end customer additions are used to calculate Capital Expenditures driven by customer addition.

2007 Forecast inclusive of 3,464 customers from the former TGS customers.

Note 2 Year-over-year change excludes forecasted 2006 TGS customers (year end: 3,224 customers; average: 3,074 customers) that were rolled into the amalgamated TGI prior to 2007.

Note 3 The percentage growth in average customer is used to calculate the formula based O & M Expense and Other Base Capital Expenditures. O & M Expense is to be per the PBR formula, even for the amalgamated TGS customers. However, any shortfall between the aforementioned PBR formula based amount and the existing TGS 1977 Settlement formula based amount is to be captured in a deferral account.

2007 Forecast inclusive of 3,352 customers from the former TGS customers.

Note 4 Pursuant to the provisions of the July 29, 2003 BCUC Decision, the 2007 B.C. inflation forecast will be determined as the average of the forecasts from the Conference Board of Canada, the B.C. Ministry of Finance, the RBC Financial Group, and the Toronto-Dominion Bank.

Based on this formula, the B.C. CPI forecast for 2007 is 2.0%, and represents the average of the forecasts below:

Conference Board of Canada	1.9%	(July 2006)
B.C. Ministry of Finance	2.1%	(February 2006)
RBC Financial Group	2.3%	(June 2006)
Toronto-Dominion Bank	1.8%	(Sep 2006)

(Copies of the forecasts are attached as Attachment A)

Note 5 Pursuant to the provisions of BCUC Order G-51-03, the adjustment factor will be 66% of CPI for 2007 equal to 1.32%.

Official Forecasts of British Columbia Consumer Price Index

October 10, 2006

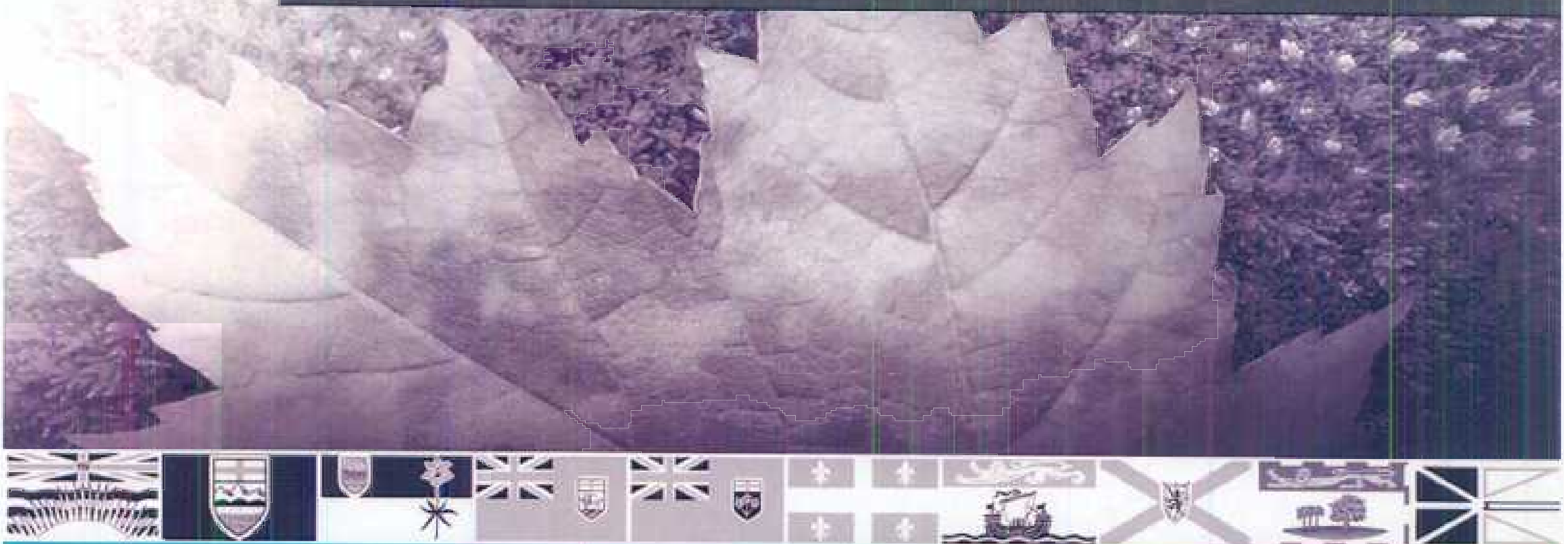
Source	Forecast Date	Percent Change	
		2006	2007
Conference Board of Canada	July 2006	1.9 %	1.9 %
BC Ministry of Finance	February 2006	2.2 %	2.1 %
RBC Financial Group	June 2006	2.0 %	2.3 %
TD Bank Financial Group	Sept 2006	2.0 %	1.8 %
Average		**2.025%**	**2.0%**

TAB A-2 2007 COST DRIVERS

ATTACHMENT A

The Conference Board of Canada
Insights You Can Count On

Provincial Outlook Summer 2006



Economic Forecast

ECONOMIC PERFORMANCE AND TRENDS

Key Economic Indicators: British Columbia
(Forecast completed: July 17, 2006)

	2005:1	2005:2	2005:3	2005:4	2006:1	2006:2	2006:3	2006:4	2007:1	2007:2	2007:3	2007:4	2005	2006	2007
GDP at market prices (current $)	163,661	167,134	168,006	174,095	175,523	177,468	179,243	180,652	182,795	185,258	187,615	189,772	168,224	178,221	186,360
	2.3	*2.1*	*0.5*	*3.6*	*0.8*	*1.1*	*1.0*	*0.8*	*1.2*	*1.3*	*1.3*	*1.1*	*6.6*	*5.9*	*4.6*
GDP at basic prices (current $)	150,141	153,285	154,132	160,200	161,367	163,111	165,310	166,530	168,523	170,823	173,016	175,006	154,439	164,079	171,842
	2.4	*2.1*	*0.6*	*3.9*	*0.7*	*1.1*	*1.3*	*0.7*	*1.2*	*1.4*	*1.3*	*1.2*	*6.7*	*6.2*	*4.7*
GDP at basic prices (constant $ 1997)	129,631	131,459	132,833	134,286	135,401	136,208	137,294	138,174	139,441	140,602	141,542	142,449	132,052	136,769	141,008
	0.3	*1.4*	*1.0*	*1.1*	*0.8*	*0.6*	*0.8*	*0.6*	*0.9*	*0.8*	*0.7*	*0.6*	*3.7*	*3.6*	*3.1*
Consumer price index (1992 = 1.0)	1.238	1.252	1.260	1.261	1.259	1.278	1.281	1.288	1.293	1.298	1.303	1.310	1.253	1.277	1.301
	0.2	*1.1*	*0.7*	*0.0*	*−0.1*	*1.5*	*0.2*	*0.6*	*0.4*	*0.4*	*0.4*	*0.5*	*2.0*	*1.9*	*1.9*
Implicit price deflator— GDP at basic prices (1997 = 1.0)	1.158	1.166	1.160	1.193	1.192	1.198	1.204	1.205	1.209	1.215	1.222	1.229	1.169	1.200	1.219
	2.1	*0.7*	*−0.5*	*2.8*	*−0.1*	*0.5*	*0.5*	*0.1*	*0.3*	*0.5*	*0.6*	*0.5*	*2.8*	*2.6*	*1.6*
Average weekly wages (level)	681.1	700.7	705.9	709.8	714.3	721.5	724.4	728.8	735.0	742.9	747.6	752.4	699.4	722.3	744.5
	−0.5	*2.9*	*0.7*	*0.6*	*0.6*	*1.0*	*0.4*	*0.6*	*0.9*	*1.1*	*0.6*	*0.6*	*2.9*	*3.3*	*3.1*
Personal income (current $)	125,848	128,882	130,853	132,544	134,783	138,239	139,591	139,721	141,904	143,869	145,477	147,030	129,532	138,083	144,570
	0.6	*2.4*	*1.5*	*1.3*	*1.7*	*2.6*	*1.0*	*0.1*	*1.6*	*1.4*	*1.1*	*1.1*	*5.4*	*6.6*	*4.7*
Personal disposable income (current $)	97,788	100,177	101,447	102,884	104,614	108,649	109,618	108,849	110,966	112,396	113,187	114,348	100,574	107,932	112,724
	0.2	*2.4*	*1.3*	*1.4*	*1.7*	*3.9*	*0.9*	*−0.7*	*1.9*	*1.3*	*0.7*	*1.0*	*5.0*	*7.3*	*4.4*
Personal savings rate	−6.24	−5.25	−6.04	−5.61	−5.17	−3.32	−3.01	−4.43	−3.31	−3.38	−3.83	−3.86	−5.78	−3.96	−3.60
Population of labour force age (000s)	3,423	3,439	3,456	3,473	3,488	3,503	3,513	3,523	3,534	3,545	3,556	3,566	3,448	3,507	3,550
	0.4	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.7*	*1.7*	*1.2*
Labour force (000s)	2,254	2,258	2,264	2,276	2,287	2,296	2,311	2,325	2,338	2,348	2,358	2,367	2,263	2,305	2,353
	1.1	*0.2*	*0.3*	*0.5*	*0.5*	*0.4*	*0.7*	*0.6*	*0.6*	*0.4*	*0.5*	*0.4*	*1.9*	*1.8*	*2.1*
Employment (000s)	2,103	2,124	2,133	2,162	2,177	2,193	2,197	2,204	2,216	2,226	2,236	2,245	2,130	2,193	2,231
	1.0	*1.0*	*0.4*	*1.4*	*0.7*	*0.7*	*0.2*	*0.3*	*0.6*	*0.4*	*0.5*	*0.4*	*3.3*	*2.9*	*1.7*
Unemployment rate	6.7	5.9	5.8	5.0	4.8	4.5	4.9	5.2	5.2	5.2	5.2	5.2	5.9	4.9	5.2
Retail sales (current $)	48,632	49,579	50,912	50,986	51,947	51,785	52,669	52,650	53,213	53,994	54,618	55,187	50,027	52,263	54,253
	1.1	*1.9*	*2.7*	*0.1*	*1.9*	*−0.3*	*1.7*	*0.0*	*1.1*	*1.5*	*1.2*	*1.0*	*6.0*	*4.5*	*3.8*
Housing starts (units)	33,365	32,536	35,574	37,192	41,907	34,400	33,321	32,970	32,273	31,529	31,261	30,814	34,667	35,650	31,469
	6.1	*−2.5*	*9.3*	*4.6*	*12.7*	*−17.9*	*−3.1*	*−1.1*	*−2.1*	*−2.3*	*−0.8*	*−1.4*	*5.3*	*2.8*	*−11.7*

White area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; Canada Mortgage and Housing Corporation.

Budget and Fiscal Plan 2006/07 – 2008/09

February 21, 2006

BRITISH COLUMBIA
Ministry of Finance

www.gov.bc.ca

Forecast Survey – Participants' Opinions

All figures are based on annual averages	2005 Range	2005 Average[1]	2006 Range	2006 Average[1]	2007 Range	2007 Average[1]	2008 to 2010 Range	2008 to 2010 Average[2]
United States								
Real GDP (% change)	3.4 – 3.6	3.6 (13)[3]	2.8 – 3.7	3.3 (13)	1.7 – 3.5	3.0 (13)	2.2 – 3.5	3.1 (13)
Intended Federal Funds rate (%)	3.10 – 3.50	3.27 (12)	4.07 – 4.75	4.42 (12)	3.50 – 5.25	4.44 (12)	2.50 – 5.25	4.43 (12)
Housing starts (million units)	2.00 – 2.10	2.05 (12)	1.79 – 1.92	1.87 (12)	1.70 – 1.85	1.77 (12)	1.50 – 2.00	1.71 (12)
Canada								
Real GDP (% change)	2.7 – 3.0	2.9 (13)	2.6 – 3.5	3.0 (13)	1.5 – 3.3	2.8 (13)	2.2 – 3.0	2.9 (13)
Bank of Canada Overnight Target rate (%)	2.57 – 2.85	2.70 (12)	3.50 – 4.19	3.81 (12)	2.90 – 4.50	3.89 (12)	2.50 – 4.70	4.06 (12)
Exchange rate (US cents/C$)	82.0 – 84.0	82.6 (13)	81.0 – 87.8	84.8 (13)	80.0 – 90.0	84.8 (13)	81.0 – 87.5	84.3 (13)
Consumer price index (% chg)...	2.2 – 2.5	2.3 (13)	1.8 – 2.7	2.2 (13)	1.4 – 2.8	2.0 (13)	1.2 – 3.0	2.0 (13)
British Columbia								
Real GDP (% change)	3.3 – 4.5	3.8 (13)	3.3 – 4.1	3.6 (13)	2.2 – 3.9	3.2 (13)	2.7 – 3.8	3.2 (13)
Nominal GDP (% change)	4.2 – 7.6	6.4 (12)	4.3 – 7.2	5.8 (12)	3.8 – 6.5	5.1 (12)	4.1 – 6.6	5.2 (12)
GDP Deflator (% change)	1.8 – 3.8	2.9 (12)	0.9 – 3.4	2.4 (12)	0.9 – 3.3	2.1 (12)	1.3 – 3.3	2.1 (12)
Personal Income (% change)	4.8 – 6.6	5.6 (11)	5.0 – 6.6	5.7 (11)	4.1 – 6.7	5.3 (11)	4.3 – 6.8	5.2 (11)
Net Migration (thousand persons)	35.0 – 50.0	41.2 (12)	30.5 – 58.0	42.7 (12)	28.0 – 60.0	45.1 (12)	23.0 – 65.0	47.3 (12)
Employment (% change)	2.0 – 3.3	3.0 (12)	1.8 – 3.1	2.4 (12)	1.0 – 3.0	2.1 (12)	1.0 – 3.0	2.0 (12)
Unemployment rate (%)	5.8 – 6.2	6.0 (13)	4.9 – 6.0	5.4 (13)	4.3 – 6.0	5.3 (13)	4.2 – 5.8	5.1 (13)
Corporate pre-tax profits (% change)	2.0 – 30.0	11.1 (7)	0.4 – 20.0	8.1 (7)	2.0 – 15.0	6.3 (7)	4.0 – 15.0	7.5 (6)
Housing starts (thousand units)	32.0 – 36.0	33.8 (13)	29.6 – 35.5	32.9 (13)	25.8 – 37.0	31.8 (13)	23.6 – 40.0	31.4 (13)
Retail sales (% change)	5.8 – 7.1	6.4 (13)	4.3 – 7.3	5.9 (13)	4.0 – 7.3	5.5 (13)	3.9 – 7.0	5.4 (13)
Consumer price index (% chg)...	2.0 – 2.3	2.1 (13)	1.9 – 2.9	2.2 (13)	1.6 – 3.0	2.1 (13)	1.4 – 3.0	2.2 (13)

[1] Based on responses from participants providing forecasts.
[2] Participants provided an average forecast for 2008 to 2010.
[3] Number of respondents shown in parenthesis.

RBC Financial Group

Provincial Outlook

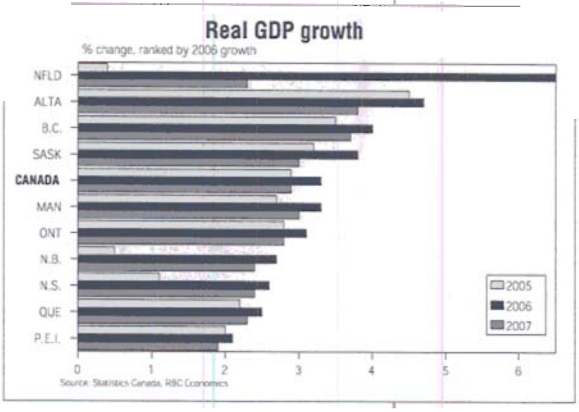
Quarterly forecasts with forecast detail tables for each of Canada's provincial economies.

Some shine taken off resource provinces

June 2006

Recent developments in global financial markets will yield disparate regional economic effects. Our base case assumption is that the recent and rapid correction in a number of commodity prices is justified in removing some speculative excesses. From peaks in mid-May, base metal prices have experienced across the board double-digit percentage declines. Furthermore, oil is 8% off its April peak, and natural gas is down 60% this year.

The impact will first show up through provincial fiscal positions by way of a hit to royalty revenues. The extreme case is Alberta, which is much more sensitive to royalties on natural gas than oil. So far this fiscal year, natural gas prices are averaging C$3.3 per gigajoule lower than the average in FY2005-06, which means a $3.4 billion hit to provincial coffers. The fact that average oil prices are about US$11 per WTI barrel higher this fiscal year compared to last will provide a $1.3 billion offset. The net oil and gas effect is a $2.1 billion hit such that the $7.4 billion surplus in FY2005-06 is best viewed through a rear-view mirror.

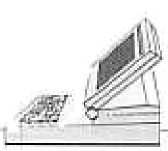


The economic effects, however, will become more widespread in a lagged manner. If commodity price and Canadian dollar corrections are as sustained as we believe they will be, this should rein in growth prospects in resource-intensive parts of the country while providing some relief to the manufacturing heartland of Ontario and Quebec.

It is within this environment that additional risks must be considered. A variety of measures show that housing markets are slowing across the eastern half of the country. The western half will join the slowdown next year as rising mortgage rates and softening commodity prices assist in narrowing the large growth gap between prices and incomes.

Labour markets present further risks. Alberta is draining workers from the rest of Canada at a time when labour markets are tight in most areas, which makes it difficult to do so. Boosting immigration quotas would be an effective way of helping ease this pressing shortage that has cyclical and structural drivers. In the absence of higher quotas, however, labour shortages have translated into higher wages that are raising cost-push inflationary pressures. While British Columbia and Alberta are leading the wage gains, the rest of Canada is not far behind with wage earnings up 4.4% this quarter compared to a year ago.

Against the backdrop of these risks, however, are a geographically diversified investment-led expansion, a strong consumer sector and a sound fiscal policy backdrop. The recent budget season painted a bright fiscal picture that lends support to the domestic economy. Eight of 10 provinces reported surpluses and the remaining two hold onto them by choice but should easily achieve balance next year. Indeed, Canada is the envy of many countries by being well-positioned to absorb shocks to the global economy.



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British Columbia

		1999	2000	2001	2002	2003	2004	2005	2006	2007
Gross domestic product	$ millions	120,921	131,333	133,514	138,252	145,948	157,241	168,011	178,764	189,490
	% change	4.6	8.6	1.7	3.5	5.6	7.7	6.8	6.4	6.0
Real GDP	$1997 millions	119,604	125,145	125,924	130,324	133,888	139,205	144,028	149,789	155,331
	% change	3.2	4.6	0.6	3.5	2.7	4.0	3.5	4.0	3.7
Employment	thousands	1,894.4	1,931.3	1,921.6	1,965.0	2,014.7	2,062.7	2,130.5	2,205.1	2,247.0
	% change	1.9	1.9	-0.5	2.3	2.5	2.4	3.3	3.5	1.9
Labour force	thousands	2,064.8	2,079.9	2,082.6	2,147.6	2,190.7	2,221.9	2,263.4	2,313.2	2,359.5
	% change	1.3	0.7	0.1	3.1	2.0	1.4	1.9	2.2	2.0
Unemployment rate	%	8.3	7.1	7.7	8.5	8.0	7.2	5.9	4.7	4.8
Personal disposable income	$ millions	77,412	81,901	85,332	88,555	91,070	94,724	99,306	107,250	112,828
	% change	4.1	5.8	4.2	3.8	2.8	4.0	4.8	8.0	5.2
Retail sales	$ millions	36,373	38,435	40,719	43,265	44,421	47,217	50,027	53,479	56,902
	% change	1.7	5.7	5.9	6.3	2.7	6.3	6.0	6.9	6.4
Housing starts	units	16,309	14,418	17,234	21,625	26,174	32,925	34,667	37,440	32,573
	% change	-18.2	-11.6	19.5	25.5	21.0	25.8	5.3	8.0	-13.0
Consumer price index	1992=100	111.2	113.3	115.2	117.9	120.4	122.8	125.3	127.8	130.7
	% change	1.1	1.9	1.7	2.3	2.1	2.0	2.0	2.0	2.3

Alberta

		1999	2000	2001	2002	2003	2004	2005	2006	2007
Gross domestic product	$ millions	117,080	144,789	151,274	150,814	171,175	187,152	215,858	237,660	251,919
	% change	9.0	23.7	4.5	-0.3	13.5	9.3	15.3	10.1	6.0
Real GDP	$1997 millions	114,227	121,153	123,250	126,328	130,256	135,837	141,992	148,666	154,315
	% change	1.4	6.1	1.7	2.5	3.1	4.3	4.5	4.7	3.8
Employment	thousands	,544.0	1,584.0	1,630.9	1,670.8	1,716.7	1,757.5	784.4	1,850.4	1,889.3
	% change	2.3	2.6	3.0	2.4	2.7	2.4	1.5	3.7	2.1
Labour force	thousands	1,637.7	1,666.8	1,710.3	1,764.2	1,808.8	1,842.4	,857.5	1,922.5	1,964.8
	% change	2.4	1.8	2.6	3.2	2.5	1.9	0.8	3.5	2.2
Unemployment rate	%	5.7	5.0	4.6	5.3	5.	4.6	3.9	3.7	3.8
Personal disposable income	$ millions	61,845	67,790	75,535	78,022	81,268	86,410	93,384	102,349	108,387
	% change	4.7	9.6	11.4	3.3	4.2	6.3	8.1	9.6	5.9
Retail sales	$ millions	29,454	31,738	34,560	37,663	39,318	43,372	48,758	54,804	60,339
	% change	4.1	7.8	8.9	9.0	4.4	10.3	12.4	12.4	10.1
Housing starts	units	25,447	26,266	29,174	38,754	36,171	36,270	40,847	45,749	38,429
	% change	-6.2	3.2	11.1	32.8	-6.7	0.3	12.6	12.0	-16.0
Consumer price index	1992=100	113.4	117.4	120.1	124.2	129.7	131.5	134.3	138.5	142.3
	% change	2.4	3.5	2.3	3.4	4.4	1.4	2.1	3.1	2.8

REAL GROSS DOMESTIC PRODUCT (GDP)
Annual average per cent change

	2004	2005	2006f	2007f	2008f
CANADA	2.9	2.9	2.8	2.3	3.2
N. & L.	-1.4	0.4	3.6	2.6	2.0
P.E.I.	1.8	2.0	1.8	1.5	2.5
N.S.	1.4	1.1	2.4	2.0	2.7
N.B.	2.0	0.5	2.9	1.4	2.9
Quebec	2.3	2.2	1.9	1.8	3.2
Ontario	2.7	2.8	1.8	2.0	3.6
Manitoba	2.3	2.7	2.7	2.5	3.0
Sask.	3.4	3.2	2.7	2.5	2.7
Alberta	4.3	4.5	6.8	3.6	2.9
B.C.	4.0	3.5	4.0	3.0	3.3

f: forecast by TD Economics as at September 2006
Source: Statistics Canada

TOTAL CONSUMER PRICE INDEX
Annual average per cent change

	2004	2005	2006f	2007f	2008f
CANADA	1.9	2.2	2.4	1.9	2.2
N. & L.	1.8	2.6	2.2	1.7	1.9
P.E.I.	2.1	3.2	3.0	2.0	2.0
N.S.	1.8	2.8	2.3	1.8	2.1
N.B.	1.5	2.4	2.1	1.6	2.1
Quebec	1.9	2.3	2.1	1.7	2.1
Ontario	1.9	2.2	2.1	1.7	2.3
Manitoba	2.0	2.7	2.2	1.9	2.2
Sask.	2.2	2.2	2.3	1.9	2.1
Alberta	1.4	2.1	4.2	3.5	3.0
B.C.	2.0	2.0	2.0	1.8	2.1

f: forecast by TD Economics as at September 2006
Source: Statistics Canada

EMPLOYMENT
Annual average per cent change

	2004	2005	2006f	2007f	2008f
CANADA	1.8	1.4	1.9	1.0	1.2
N. & L.	1.0	-0.1	0.0	0.3	0.5
P.E.I.	1.3	2.0	0.8	0.5	0.6
N.S.	2.6	0.2	0.3	0.5	0.7
N.B.	2.1	0.1	2.0	0.3	0.8
Quebec	1.5	1.0	1.3	0.6	0.8
Ontario	1.7	1.3	1.7	0.8	1.4
Manitoba	1.1	0.6	1.0	0.7	0.8
Sask.	0.8	0.8	0.2	0.8	0.8
Alberta	2.4	1.5	4.0	2.0	1.8
B.C.	2.4	3.3	3.0	1.5	1.7

f: forecast by TD Economics as at September 2006
Source: Statistics Canada

UNEMPLOYMENT RATE
Per cent

	2004	2005	2006f	2007f	2008f
CANADA	7.2	6.8	6.3	6.5	6.4
N. & L.	15.7	15.2	15.6	15.9	16.3
P.E.I.	11.4	10.8	11.1	11.4	11.3
N.S.	8.8	8.4	8.6	9.0	8.9
N.B.	9.8	9.7	9.4	9.9	9.6
Quebec	8.5	8.3	8.4	8.9	8.7
Ontario	6.8	6.6	6.3	6.7	6.3
Manitoba	5.3	4.8	4.5	4.8	5.1
Sask.	5.4	5.1	5.1	5.3	5.4
Alberta	4.6	3.9	3.3	4.0	4.5
B.C.	7.2	5.9	4.6	5.3	5.2

f: forecast by TD Economics as at September 2006
Source: Statistics Canada, TD Economics

HOUSING STARTS
Thousands of units

	2004	2005	2006f	2007f	2008f
CANADA	233.4	225.5	227.0	195.0	170.0
N. & L.	2.9	2.5	2.3	1.9	1.6
P.E.I.	0.9	0.9	0.9	0.7	0.6
N.S.	4.7	4.8	5.5	4.2	4.1
N.B.	3.9	4.0	4.2	3.2	3.0
Quebec	58.4	50.9	44.3	36.0	32.0
Ontario	85.1	78.8	75.0	67.4	64.5
Manitoba	4.4	4.7	5.0	4.5	4.2
Sask.	3.8	3.4	3.3	3.1	2.8
Alberta	36.3	40.8	49.5	42.0	37.0
B.C.	32.9	34.7	37.0	32.0	30.2

f: forecast by TD Economics as at September 2006
Source: Canada Mortgage and Housing Corporation

RESALE HOME PRICES
Annual average per cent change

	2005 (000$)	2005	2006f	2007f	2008f
CANADA	249.3	10.2	9.6	4.8	3.4
N. & L.	141.2	7.4	2.0	2.0	1.6
P.E.I.	117.2	5.8	3.2	2.5	2.2
N.S.	159.6	9.3	10.5	4.0	3.5
N.B.	120.6	6.8	4.3	3.0	2.5
Quebec	184.6	7.9	6.5	2.7	2.0
Ontario	263.0	7.3	5.9	2.9	2.5
Manitoba	133.9	12.3	7.5	5.2	4.0
Sask.	122.8	10.8	8.4	5.5	3.5
Alberta	218.3	12.1	20.5	10.0	5.0
B.C.	332.2	14.9	13.5	7.0	5.0

f: forecast by TD Economics as at September 2006
Source: Canada Mortgage and Housing Corporation

TERASEN GAS INC.

2006 ANNUAL REVIEW
2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

REVISED FORECASTS AND PROJECTIONS FOR
2007 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-3 INDEX

2007 RATE BASE

The 2007 Rate Base for the amalgamated TGI is forecast to be $2.474 billion. Rate Base is composed of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, cash working capital, other working capital, deferred income tax, LILO benefit and TGS' rate base as at December 31, 2006.

The 2007 Rate Base of the amalgamated TGI includes full year impacts of the 2006 projected plant activities including:

- 2006 actual CPCN Opening Additions of $4.3 million
- Formula-Based Capital Additions of $125.9 million
- Plant Accumulated Depreciation and CIAOC Amortization of $85.6 million

Also, the 2007 Rate Base includes 2007 activities including:

- 2007 CPCN Opening Additions assets of $8.1 million
- Base Capital Additions of $129.7 million
- Plant Depreciation and CIAOC Amortization of $87.4 million
- Various changes in deferred charges, working capital and other items decreasing rate base by a net amount of $69.2 million.

Details of the 2006 projected plant balances and the 2007 forecasted plant balances can be found in Section A, Tab 3, Pages 8 and 8.1.

2007 CAPITAL EXPENDITURES

The 2007 Capital Expenditures are based on the capital expenditure formula (approved by Commission Order No. G-51-03) plus forecast CPCNs. The capital expenditure formula is composed of two cost components: Customer Addition Driven Capital and Other Base Capital driven by average number of customers.

Per Commission Order No. G-51-03, base capital expenditure amounts will not be rebased to actual amounts during the term. For the rate setting in subsequent years the formula base capital expenditures from the prior years will be adjusted for projected customer counts and trued up for actual customers as this information becomes known. There is no true up for actual CPI.

During the 2005 annual review, Terasen Gas had forecast 12,692 customer additions along with 804,316 average number of customers for 2006. The current projection for 2006 is 12,726 and 803,686, respectively. Accordingly, the total formula-based capital expenditures for 2006 derived from the projected customer addition numbers has increased from $97.985 million to $98.002 million. Supporting calculations can be found at Tab 3, Page 5.

The 2007 Capital Expenditure for the amalgamated TGI is calculated using the 2007 Forecast Unit Cost multiplied by customer accounts cost drivers as outlined in Tab 2, Page 1. The detail calculation is shown on Tab 3, Page 5.

- 2007 Forecast Unit Cost per Customer =
    - 2006 Unit Cost per Customer x ([1 + (CPI - Adjustment Factor)
- 2007 Capital Expenditure =
    - 2007 Forecast Unit Cost per customer x Cost Driver
    - The Cost Driver for:
        - Customer Addition Driven Capital is Number of Customer Additions
        - Other Base Capital is Average Number of Customers

2007 PLANT ADDITIONS

The 2007 Plant Additions are comprised of TGI's 2007 formula-driven Base Capital plant costs including AFUDC, overhead capitalized for the year, and opening 2007 CPCN Additions. The opening 2007 CPCN plant additions consist of TGS' assets as at December 31, 2006 totaling $8.1 million which will become part of the TGI rate base as part of the TGI-TGS amalgamation process. A reconciliation of capital expenditures to plant additions is shown on Section A, Tab 3, Page 6. Supporting financial details of Squamish Gas can be found under Section A, Tab 8.

The 2007 Plant Additions allowed by the terms of the Settlement, including TGS, is $137.854 million. The Plant Addition summary is shown below:

2007 Plant Additions	
Formula-based Base Capital	$ 101.570 million
Overhead Capitalized	$ 27.535 million
AFUDC and WIP adjustments	$0.612 million
Opening CPCN – Terasen Gas (Squamish) amalgamation	$8.137 million
Total 2007 Plant Additions	$ 137.854 million

Consistent with the terms of the Settlement, the 2007 Contributions in Aid of Construction Additions ("CIAOC") are formula-based. The software tax savings are based on the software plant additions arising from the base capital additions formula. TGI's Service Line Installation Fee is calculated based on $215 per service line. The other CIAOC consisting of main extensions, excess service line charges, billable alterations, meter & regulator equipment work, and other CIAOC have been calculated based on the PBR Formula. TGS' CIAOC as at December 31, 2006 has been included in Tab 3, Page 9, Column 6. CIAOC is subject to the same adjustment and true-up process as base capital additions. Therefore, the CIAOC additions for 2007 have been adjusted based on projected 2006 customer counts. The 2007 CIAOC and 2006 formula updated CIAOC schedules can be found in Section A, Tab 3, Page 9.

AMALGAMATED TGI (Terasen Gas Inc. + Terasen Gas Squamish Inc.)
CAPITAL EXPENDITURES
FOR THE YEARS ENDING DECEMBER 31, 2006 and 2007

Line. No.	Particulars	Terasen Gas Inc. PBR Settlement 2003	Approved 2004	Adjusted 2004	Approved 2005	Adjusted 2005	Approved 2006	Adjusted 2006	TGI + TGS Forecast 2007	TGI Forecast 2007	TGS Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Forecast CPI (BC)		1.70%	1.99%	2.00%	2.04%	2.20%	2.20%	2.00%	2.00%	2.00%
2	Adjustment Factor		0.85%	1.00%	1.00%	1.02%	1.45%	1.45%	1.32%	1.32%	1.32%
3											
4	CPI - Adjustment Factor		100.85%	101.00%	101.00%	101.02%	100.75%	100.75%	100.68%	100.68%	100.68%
5											
6											
7	**CUSTOMER ADDITION DRIVEN CAPITAL EXPENDITURES**										
8											
9	Customer Addition Driven Capital Expenditures Per Customer Addition	$2,093.04	$2,110.83	$2,110.83	$2,131.94	$2,131.94	$2,147.89	$2,147.89	$2,162.50	$2,162.50	$2,162.50
10											
11	Number of Customers Additions		8,604	11,504	10,144	12,345	12,692	12,726	13,385	13,145	240
12											
13	**Target Customer Addition Driven Capital Expenditures ($000)**		**$18,162**	**$24,283**	**$21,626**	**$26,319**	**$27,261**	**$27,334**	**$28,945**	**$28,426**	**$519**
14											
15											
16	**OTHER BASE CAPITAL EXPENDITURES**										
17											
18	Other Base Capital Expenditures Per Customer	$85.69	$86.42	$86.42	$87.28	$87.28	$87.93	$87.93	$88.53	$88.53	$88.53
19											
20	Average Number of Customers		777,779	779,461	790,385	791,593	804,316	803,686	820,347	816,995	3,352
21											
22	**Target Other Base Capital Expenditures ($000)**		**$67,216**	**$67,361**	**$68,985**	**$69,090**	**$70,724**	**$70,668**	**$72,625**	**$72,329**	**$296**
23											
24											
25											
26	**SUMMARY CAPITAL EXPENDITURES ($000)**										
27											
28	Target Customer Addition Driven Capital Expenditures		$18,162	$24,283	$21,626	$26,319	$27,261	$27,334	$28,945	$28,426	$519
29	Target Other Base Capital Expenditures		67,216	67,361	68,985	69,090	70,724	70,668	72,625	72,329	296
30											
31	Total Target Base Capital Expenditures		$85,378	$91,644	$90,611	$95,409	$97,985	$98,002	$101,570	$100,755	$815
32											
33											
34	**Total Base Capital Additions excluding Forecast CPCN Additions ($000)**		**$85,378**	**$91,644**	**$90,611**	**$95,409**	**$97,985**	**$98,002**	**$101,570**	**$100,755**	**$815**
35											

AMALGAMATED TGI (TERASEN GAS INC. + TERASEN GAS SQUAMISH INC.)
CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2006 - 2007
($000)

Line No.	Particulars	TGI Approved 2006	TGI Adjusted 2006	TGI + TGS Forecast 2007	TGI Forecast 2007	TGS Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)
1	**CAPITAL EXPENDITURES**					
2						
3	Base Capital Expenditures					
4	Customer Addition Driven Capital Expenditures	$27,261	$27,334	$28,945	$28,426	$519
5	Other Base Capital Expenditures	70,724	70,668	72,625	72,329	296
6						
7	Total Base Capital Expenditures	$97,985	$98,002	$101,570	$100,755	$815
8						
9	Special Projects - CPCNs					
10	Southern Crossing Pipeline	$0	$0	$0	$0	$0
11	Vancouver LP Replacement		5,674	8,706	8,706	
12	Mission IP System Upgrade		949	7,345	7,345	
13	Gateway Project		187	11,900	11,900	
14	SBSA Seimic Rehab			1,500	1,500	
15	TGS Amalgamation	9,070	0	8,137	0	8,137
16						
17	Total CPCNs	$9,070	$6,810	$37,588	$29,451	$8,137
18						
19						
20	TOTAL CAPITAL EXPENDITURES	$107,055	$104,812	$139,158	$130,206	$8,952
21						
22						
23	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**					
24						
25	Base Capital					
26	Base Capital Expenditures	$97,985	$98,002	$101,570	$100,755	$815
27	Add - Opening WIP	11,951	11,917	12,209	12,209	
28	Less - Opening WIP adjustment	0	0	0	0	
29	Less - Closing WIP	(12,215)	(12,209)	(12,584)	(12,516)	(68)
30						
31	Add - AFUDC	960	959	987	982	5
32	Add - Overhead Capitalized	27,243	27,243	27,535	27,429	106
33						
34	TOTAL BASE CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$125,925	$125,912	$129,717	$128,859	$858
35						
36	Special Projects - CPCNs					
37	CPCNs Expenditures	$9,070	$6,810	$37,588	$29,451	$8,137
38	Add - Opening WIP	4,564	4,336	6,918	6,918	
39	Less - Closing WIP	(9,070)	(6,918)	(37,403)	(37,403)	
40						
41	Add - AFUDC	0	108	1,034	1,034	
42						
43	TOTAL CPCN ADDITIONS TO OPENING GAS PLANT IN SERVICE	$4,564	$4,336	$8,137	$0	$8,137
44						
45						
46	TOTAL PLANT ADDITIONS	$130,489	$130,248	$137,854	$128,859	$8,995

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 Adjustments	2007 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$3,067,485	$3,140,710	$0	$3,140,710	$73,225	- Tab A-3, Page 8.1
2	CPCNs	4,564	8,137	0	8,137	3,573	- Tab A-3, Page 8.1
3							
4	Additions	125,924	129,717	0	129,717	3,793	- Tab A-3, Page 8.1
5	Disposals	(56,345)	(32,918)	0	(32,918)	23,427	- Tab A-3, Page 8.1
6							
7	Plant in Service, Ending	3,141,628	3,245,646	0	3,245,646	104,018	
8							
9	Add - Intangible Plant	837	1,614	0	1,614	777	
10							
11		3,142,465	3,247,260	0	3,247,260	104,795	
12							
13	Contributions In Aid of Construction	(137,019)	(131,162)	0	(131,162)	5,857	- Tab A-3, Page 9
14							
15	Less - Accumulated Depreciation	(671,378)	(744,227)	0	(744,227)	(72,849)	- Tab A-3, Page 15
16							
17							
18	Net Plant in Service, Ending	$2,334,068	$2,371,871	$0	$2,371,871	$37,803	
19							
20							
21	Net Plant in Service, Beginning	$2,302,480	$2,339,687	$0	$2,339,687	$37,207	- Tab A-3, Page 10
22							
23							
24	Net Plant in Service, Mid-Year	$2,318,274	$2,355,779	$0	$2,355,779	$37,505	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(11)	(11)	0	(11)	0	
27	Work in Progress, No AFUDC	11,902	10,771	0	10,771	(1,131)	
28	Unamortized Deferred Charges	13,109	(8,227)	0	(8,227)	(21,336)	- Tab A-3, Page 13.1
29	Cash Working Capital	(29,050)	(25,214)	17	(25,197)	3,853	- Tab A-3, Page 14
30	Other Working Capital	194,361	143,982	0	143,982	(50,379)	- Tab A-3, Page 14
31	Deferred Income Tax, Mid-Year	(364)	(606)	0	(606)	(242)	
32	LILO Benefit	(2,312)	(2,243)	0	(2,243)	69	
33	Utility Rate Base	$2,505,909	$2,474,231	$17	$2,474,248	($31,661)	

GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	Balance 12/31/2005	CPCN'S	2006 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2006	CPCN'S	2007 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	401 Franchise Consents	$99	$0	$0	$0	$0	$99	$0	$0	$0	$0	$99
2	402 Other Intangible Plant	835	0	0	0	0	835	0	0	0	0	835
3	TOTAL INTANGIBLE PLANT	934	0	0	0	0	934	0	0	0	0	934
4												
5	430 Manufact'd Gas - Land	31	0	0	0	0	31	0	0	0	0	31
6	432 Manufact'd Gas - Struct. & Improvements	438	0	0	0	0	438	0	0	0	0	438
7	433 Manufacturing Equipment	139	0	0	0	0	139	0	0	0	0	139
8	434 Gas Holders - Manufacturing	358	0	0	0	0	358	0	0	0	0	358
9	436 Compressed Equipment	53	0	0	0	0	53	0	0	0	0	53
10	437 Measuring and Regulating Equipment	309	0	0	0	0	309	0	0	0	0	309
11	440/441 Land in Fee Simple and Land Rights	927	0	0	0	0	927	0	0	0	0	927
12	442 Structures and Improvements	5,455	0	0	0	0	5,455	0	0	0	0	5,455
13	443 Gas Holders - Storage	17,358	0	600	0	0	17,958	0	611	0	0	18,569
14	446 Compressor Equipment	0	0	0	0	0	0	0	0	0	0	0
15	447 Measuring and Regulating Equipment	0	0	0	0	0	0	0	0	0	0	0
16	448 Purification Equipment	0	0	0	0	0	0	0	0	0	0	0
17	449 Local Storage Equipment	16,734	0	0	0	0	16,734	0	0	0	0	16,734
18	TOTAL MANUFACTURED GAS / LOCAL STORAGE	41,802	0	600	0	0	42,402	0	611	0	0	43,013
19												
20	460 Land in Fee Simple	7,444	0	0	0	0	7,444	0	0	0	0	7,444
21	461 Land Rights	40,804	3	1,324	0	0	42,131	0	1,360	0	0	43,491
22	462 Compressor Structures	15,183	0	410	0	0	15,593	0	418	0	0	16,011
23	463 Measuring Structures	4,363	0	0	0	0	4,363	0	0	0	0	4,363
24	464 Other Structures and Improvements	4,881	0	0	0	0	4,881	0	0	0	0	4,881
25	465 Mains	700,807	4,176	3,271	(164)	0	708,090	0	3,331	(167)	0	711,254
26	466 Compressor Equipment	103,928	0	49	0	0	103,977	0	50	0	0	104,028
27	467 Measuring and Regulating Equipment	44,291	0	5,440	0	0	49,731	0	5,551	0	0	55,282
28	468 Communication Structures and Equipment	1,701	0	698	0	0	2,399	0	712	0	0	3,111
29	469 Other Transmission Equipment	0	0	0	0	0	0	0	0	0	0	0
30	TOTAL TRANSMISSION PLANT	923,402	4,179	11,192	(164)	0	938,609	0	11,423	(167)	0	949,865
31												
32	470 Land	3,249	0	0	0	0	3,249	0	0	0	0	3,249
33	471 Land Rights	679	0	0	0	0	679	125	0	0	0	804
34	472 Structures and Improvements	7,397	0	376	0	0	7,773	234	383	0	0	8,390
35	473 Services	560,956	0	24,466	(3,670)	0	581,752	2,189	25,575	(3,836)	0	605,680
36	474 House Regulators and Meter Installations	148,700	0	9,653	(483)	0	157,870	296	9,911	(496)	0	167,581
37	475 Mains	763,945	0	33,395	(3,339)	0	794,001	4,488	34,423	(3,442)	0	829,470
38	476 Compressor Equipment											0
39												0
40	-All Other	575	0	0	0	0	575	0	0	0	0	575
41	477 Measuring and Regulating Equipment	77,165	0	10,272	(514)	0	86,923	100	10,477	(524)	0	96,976
42	478 Meters	203,520	0	15,932	(797)	0	218,655	292	16,364	(818)	0	234,493
43	479 Other Distribution Equipment	0	0	0	0	0	0	26	0	0	0	26
44	TOTAL DISTRIBUTION PLANT	1,766,186	0	94,094	(8,803)	0	1,851,477	7,750	97,133	(9,116)	0	1,947,244

GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	Balance 12/31/2005	CPCN'S	2006 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2006	CPCN'S	2007 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	480 Land	$20,962	$0	21	0	$0	$20,983	$12	$22	$0	$0	$21,017
2	481 Land Rights	0	0	0	0	0	0	0	0	0	0	0
3	482 Structures and Improvements											
4												
5	-All Other	83,879	0	648	(180)	0	84,347	27	666	0	0	85,040
6	483 Office Furniture and Equipment											
7	-Furniture & Equipment	23,803	0	488	(48)	0	24,243	18	501	(78)	0	24,684
8	-Computers - Hardware	28,951	0	6,705	(5,917)	0	29,739	57	6,885	(7,999)	0	28,682
9	-Computer Software - Non-Infrastructure	34,648	0	2,489	(13,803)	0	23,334	2	2,551	(7,208)	0	18,679
10	-Computer Software - Infrastructure/Custom	94,809	157	6,299	(27,351)	0	73,914	0	6,456	(7,636)	0	72,734
11												
12												
13	484 Transportation Equipment	623	0	49	(7)	0	665	136	51	0	0	852
14												
15	485 Heavy Work Equipment	366	0	0	(83)	0	283	0	0	0	0	283
16	486 Tools and Work Equipment	29,239	0	2,228	(167)	0	31,300	104	2,289	(167)	0	33,526
17	487 Equipment on Customer's Premises	1,813	0	0	0	0	1,813	0	0	0	0	1,813
18	488 Communication Equipment	15,593	0	1,099	(178)	0	16,514	29	1,129	(547)	0	17,125
19	489 Other General Equipment											0
20	-Stores Material, Capital	0	0	0	0	0	0	0	0	0	0	0
21	-All Other	0	0	0	0	0	0	2	0	0	0	2
22												
23	TOTAL GENERAL EQUIPMENT	334,686	157	20,026	(47,734)	0	307,135	387	20,550	(23,635)	0	304,437
24												
25	492 Gas Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
26	496 Unclassified Plant	0	0	0	0	0	0	0	0	0	0	0
27	497 Allowance for Funds Used											0
28	During Construction	0	0	0	0	0	0	0	0	0	0	0
29	498 Overhead Charged To Construction	0	0	0	0	0	0	0	0	0	0	0
30	499 Plant Suspense	153	0	0	0	0	153	0	0	0	0	153
31												
32	TOTAL UNCLASSIFIED PLANT	153	0	0	0	0	153	0	0	0	0	153
33												
34	TOTAL CAPITAL	$3,067,163	$4,336	$125,912	($56,701)	$0	$3,140,710	$8,137	$129,717	($32,918)	$0	$3,245,646
35	ADR Settlement Proposal - 5%/10% Reduction	0	0	0	0	0	0	0				
36	O'H Capitalized Accounting Change (Adj. B1)	0	0	0	0	0	0	0	0	0	0	0
37	O'H Accounting Change Phase-In (Adj. B2)	0	0	0	0	0	0	0	0	0	0	0
38												
39	TOTAL CAPITAL	$3,067,163	$4,336	$125,912	($56,701)	$0	$3,140,710	$8,137	$129,717	($32,918)	$0	$3,245,646

TERASEN GAS INC.

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars		Balance 12/31/2005	2006 Additions	2006 Retirements	TGI Balance 12/31/2006	TGS Amalgamation	2007 Additions	2007 Retirements	Balance 12/31/2007
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	DSEP/GEAP	211-06	$12,671	$0	$0	$12,671	$0	$0	$0	$12,671
2										
3	NGV Conversion Grants	211-07	0	0	0	0	0	0	0	0
4										
5	NGV Station Grants	211-08	0	0	0	0	0	0	0	0
6										
7	Furniture & Equipment	211-10	111	0	0	111	0	0	0	111
8										
9	Software Tax Savings - Non-Infrastructure	211-11	7,613	1,068	(624)	8,057	0	964	(22)	8,999
10	- Infrastructure/Custom	211-11	37,125	2,703	(16,685)	23,143	0	2,441	(15,842)	9,742
11	Service Installation Fee	211-12	19,378	2,736	0	22,114	39	2,878	0	25,031
12										
13	Other	211-00 to 05	67,769	3,054	0	70,823	605	3,180	0	74,608
14										
15	TOTAL		144,667	9,561	(17,309)	136,919	644	9,463	(15,864)	131,162
16										
17										
18										
19	Amortization	211-15 to 22								
20										
21	- Software Tax Savings - Non-Infrastructure		(4,836)	(1,523)	624	(5,735)	0	(1,611)	22	(7,324)
22	- Infrastructure/Custom		(18,111)	(4,641)	16,685	(6,067)	0	(807)	15,842	8,968
23	- Other		(21,782)	(2,198)	0	(23,980)	(66)	(2,340)	0	(26,386)
24										
25										
26	Total Amortization		(44,729)	(8,362)	17,309	(35,782)	(66)	(4,758)	15,864	(24,742)
27										
28	NET		$99,938	$1,199	$0	$101,137	$578	$4,705	$0	$106,420

TERASEN GAS INC.

NET GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2006 TO 2007
($000)

Line No.	Particulars	Projection 2006	Forecast 2007	Reference
	(1)	(2)	(3)	(4)
1	Gas Plant in Service - December 31, Previous Year	$3,067,163	$3,140,710	- Tab A-3, Page 8.1
2				
3	Add: CPCNs on January 1, Beginning of the Year	4,336	8,137	- Tab A-3, Page 8.1
4				
5	Adjusted Opening Gas Plant in Service	3,071,499	3,148,847	
6				
7	Intangible Plant	837	1,614*	- Tab A-3, Page 7
8				
9	Less: Contribution in Aid of Construction	(144,667)	(136,919)	- Tab A-3, Page 9
10				
11	Less: Accumulated Depreciation and Amortization - TGI	(625,613)	(671,865)	- Tab A-3, Page 15
12				
13	Less: Accumulated Depreciation and Amortization - TGS	-	(1,990)	
14				
15	Net Gas Plant in Service as at January 1, Beg of Year	$2,302,056	$2,339,687	- Tab A-1, Page 6

* TGI and TGS amalgamation on January 1, 2007

DEFERRED CHARGES

The 2007 deferred charges and amortization (Section A, Tab 3, Pages 13 and 13.1) have been determined in accordance with the BCUC Decision dated February 4, 2003 on Terasen Gas' 2003 revenue requirements and the 2004-2007 PBR Plan Settlement Terms approved by Commission Order No. G-51-03.

With the implementation of the Commercial Commodity Unbundling Program the GCRA, effective April 1, 2004, was divided into a Commodity Cost Reconciliation Account (CCRA) and a Midstream Cost Reconciliation Account (MCRA).

CCRA is designated to capture and account for costs and recoveries associated with the baseload supply and for all of Terasen Gas' sales customers. MCRA is designated to capture and account for costs and recoveries associated with the remaining resources required to meet design peak day. The CCRA will capture the costs incurred by Terasen Gas to purchase its portion of the baseload gas requirements and the revenue collected by Terasen Gas through gas commodity rates. The MCRA will capture all the costs associated with the Midstream function and the revenue collected by Terasen Gas through midstream rates. The MCRA will also capture the costs associated with the Terasen Gas (Vancouver Island) Inc. Transportation Services Agreement for transportation of gas to Squamish as outlined in Section B, Tab 6.

Future disposition of CCRA/MCRA balances will be determined based on the net-of-tax balance in accordance with Commission Order No. G-34-03.

The corporate income tax rate for 2007 reflects the elimination of the Large Corporations Tax effective January 1, 2006 as announced in the 2006 Federal Budget. As per the 2004 – 2007 PBR Settlement Agreement, the impact of the LCT rate change for calendar 2006 has been deferred and will be refunded to customers over three years beginning in 2007 as shown on Section A, Tab 3, Page 13.3.

As stated under Section B, Tab 7 under Exogenous Factors, Terasen is being assessed provincial sales tax related to the SCP project. Terasen Gas does not agree with the reassessment and is appealing. While these reassessments are being appealed, Terasen Gas will remit a $10 million payment to prevent further accrual of interest, which will be refundable with interest in the event Terasen Gas is successful on appeal. Accordingly, Terasen seeks to collect in a rate base deferral account, the $10 million payment along with cost of the appeal since these are imposed on Terasen Gas by outside authorities over which the Company has no control. When the appeal is resolved, Terasen will seek a Commission order with respect to the disposition of the deferral account.

Consistent with past practice, incremental costs associated with preparing upcoming revenue requirement applications are afforded deferral treatment. Accordingly, a deferral account has been set up in Section A, Tab 3, Pages 13 and 13.3 to capture these expected costs.

To facilitate the TGI-TGS amalgamation, Terasen has set up a deferral account to capture expenses incurred to effect amalgamation as well as the difference in O&M between that of TGS customers under the PBR formula and that which would have been incurred under the TGS formula O&M. The aforementioned deferred costs are shown as part of the 2007 deferred charges and amortization schedule in Section A, Tab 3, Page 13.1. Additional information regarding the TGS amalgamation is available in Section B, Tab 6.

A result of synergies obtained through coordination with Terasen Inc.'s and Kinder Morgan Inc.'s internal audit departments, anticipated on-going costs of OSC compliance have been reduced. Costs in 2007 are estimated to be $352,000 compared to $528,000 included in the 2006 revenue requirements for Terasen Gas. These costs have been determined in accordance with the allocation process as directed by BCUC Order No. G-112-04.

BCUC levies as calculated by the O&M formula in the 2006 rates have exceeded the 2006 actual projected BCUC levies by $371,000. Terasen Gas has deferred this amount in 2006 and will return the full amount of the excess to customers in 2007.

BCUC levies embedded in 2003 Decision	$1,345,000
2006 levies as calculated with O&M formula	$1,439,000
2006 projected BCUC Levies	1,068,000
Amount to return to customers in 2007	($371,000)

The schedule of 2006 projected deferred charges and amortization is found in Section A, Tab 3, Pages 13.2 and 13.3.

TERASEN GAS INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Account	Forecast Balance 12/31/2006	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2007	Mid-Year Average 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($120)	$0	$0	$0	$69	$0	($50)	($85)
1	Deferred Interest - funding benefits via Customer Deposits		(153)		$0	$0	$72		(81)	(117)
2										
3	NGV Conversion Grants	#17977	152	70	(23)	47	(56)	0	143	148
4										
5	2003 Revenue Requirement	#17989	78	0	0	0	(49)	0	29	53
6	2004-2007 Revenue Requirements	#17952	50	0	0	0	(25)	0	25	38
7	Future Revenue Requirements	#18160	67	350	(116)	234	0	0	301	184
8										
9	Demand Side Management	#17916	1,358	1,500	(495)	1,005	(667)	0	1,695	1,527
10	DSM DRIA	#17961	0	0	0	0	0	0	0	0
11										
12	Property Tax Deferral	#17915	(493)	0	0	0	197	0	(297)	(395)
13										
14	M.C.R.A.	#17926	18,948	45,315	(14,954)	30,361	0	(49,309)	(0)	9,474
15	C.C.R.A.	#18137	(54,674)	121,800	(40,194)	81,606	0	(26,932)	(0)	(27,337)
16	C.C.R.A./M.C.R.A Interest	#17973	(2,009)	0	0	0	0	2,009	0	(1,004)
17										
18	RSAM	#17927	33,965	0	0	0	0	(11,322)	22,643	28,304
19	RSAM Interest	#17999	616	(15)	5	(10)	0	(205)	400	508
20										
21	Revelstoke Propane Cost	#27902	93	139	(46)	93	0	(186)	(0)	46
22										
23	Coastal Facilities									
24	- Extraordinary Plant Loss - Lochburn	#17998	93	0	0	0	0	0	93	93
25										
26	2005 BC Tax Rate Reduction Deferral	#17940	(21)	0	0	0	21	0	0	(11)
27										
28	Vehicle Lease Deferral	#17941	716	-	0	0	(358)	0	358	537
29										
30	Note: Lines 14, 15, and 18 are MCRA, CCRA, and RSAM actual activities and balances.									

TERASEN GAS INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Account	Balance 12/31/2006	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2007	Mid-Year Average 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ROE Hearing Costs - 2005	#17985	$449	$0	$0	$0	($150)	$0	$299	$374
2										
3	Earnings Sharing Mechanism	#17982	(8,535)	0	0	0	0	8,535	0	(4,267)
4										
5	NGV Compression Equip. Recovery	#17992	746	0	0	0	(249)	0	497	621
6										
7	Overheads Change - Income Tax Refund	#17995	(140)	0	0	0	140	0	0	(70)
8	CIAOC Software Tax Savings/OH Change	#17995	(807)	0	0	0	807	0	0	(404)
9	Bad Debt Allowance for Rates 14 & 14A	#17949	57	33	(11)	22	0	0	78	68
10	Other Post Employment Benefits	#17991/17993/2	(20,219)	(5,821)	1,921	(3,900)	0	0	(24,119)	(22,169)
11										
12	Deferred 2000 SCP Cost of Service	#17997	62	0	0	0	(62)	0	0	31
13										
14	SCP Net Mitigation Revenues	#17912	(2,757)	(955)	315	(640)	1,028	0	(2,369)	(2,563)
15	SCP West to East Transmission	#17913	189	0	0	0	(300)	0	(112)	39
16	SCP PG&E Contract Cancellation	#17936	1,988	0	0	0	(663)	0	1,325	1,656
17	SCP Provincial Sales Tax Reassessment		10,000	0	0	0	0	0	10,000	10,000
18										
19	CCT Deferral	#17924	(133)	0	0	0	133	0	0	(66)
20	CCT Assessment	#17929	161	0	0	0	(116)	0	45	103
21										
22	Pension Variance	#17946	(1,597)	0	0	0	1,597	0	0	(798)
23	Insurance Variance	#17947	(195)	0	0	0	195	0	(0)	(98)
24										
25	BCUC Levies	#18149	(240)	0	0	0	240	0	1	(120)
26	OSC Certification Compliance	#18148	(123)	352	(116)	236	(113)	0	0	(61)
27										
28	2006 LCT Elimination	#18502	(3,103)	0	0	0	1,034	0	(2,069)	(2,586)
29										
30	TGS O&M Variance		0	158	(52)	106	0	0	106	53
31										
32	TGS Amalgamation		0	200	(66)	134	0	0	134	67
33										
34	Total Deferred Charges for Rate Base		($25,534)	$163,125	($53,832)	$109,293	$2,725	($77,410)	$9,074	($8,227)

Revised: October 18, 2006

TERASEN GAS INC.

Section A
Tab 3
Page 13.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Particulars	Account	Forecast Balance 12/31/2005	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2006	Mid-Year Average 2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($1,901)	$187	($62)	$125	$1,656	$0	($120)	($1,010)
1	Deferred Interest - funding benefits via Customer Deposits		($192)	($36)	12	(24)	$63	$0	(153)	(173)
2										
3	NGV Conversion Grants	#17977	151	85	(28)	57	(56)	0	152	152
4										
5	2003 Revenue Requirement	#17989	142	0	0	0	(64)	0	78	110
6	2004-2007 Revenue Requirements	#17952	73	0	0	0	(23)	0	50	61
7	Future Revenue Requirements	#18160	0	100	(33)	67	0	0	67	34
8										
9	Demand Side Management	#17916	1,006	1,500	(495)	1,005	(654)	0	1,358	1,182
10	DSM DRIA	#17961	(145)	0	0	0	145	0	0	(73)
11										
12	Property Tax Deferral	#17915	(196)	(946)	312	(634)	336	0	(493)	(345)
13										
14	M.C.R.A.	#17926	(26,629)	40,716	(13,436)	27,280	0	18,297	18,948	(3,840)
15	C.C.R.A.	#18137	915	(82,968)	27,379	(55,589)	0	0	(54,674)	(26,880)
16	C.C.R.A./M.C.R.A Interest	#17973	(1,369)	(1,715)	566	(1,149)	0	509	(2,009)	(1,689)
17										
18	RSAM	#17927	38,784	11,450	(3,778)	7,672	0	(12,491)	33,965	36,374
19	RSAM Interest	#17999	358	478	(158)	320	0	(63)	616	487
20										
21	Revelstoke Propane Cost	#27902	208	(173)	57	(116)	0	0	93	151
22										
23	Coastal Facilities									
24	- Extraordinary Plant Loss - Lochburn	#17998	119	0	0	0	(27)	0	93	106
25										
26	2005 BC Tax Rate Reduction Deferral	#17940	(750)	0	0	0	729	0	(21)	(386)
27										
28	Vehicle Lease Deferral	#17941	1,033	-	0	0	(316)	-	716	875
29										
30	Note: Lines 14, 15, and 18 are MCRA, CCRA, and RSAM actual activities and balances.									

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Particulars	Account	Balance 12/31/2005	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2006	Mid-Year Average 2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ROE Hearing Costs - 2005	#17985	$227	$330	($109)	$221	$0	$0	$449	$338
2										
3	Earnings Sharing Mechanism	#17982	(4,860)	(12,738)	4,203	(8,535)	0	4,860	(8,535)	(6,697)
4										
5	NGV Compression Equip. Recovery	#17992	994	0	0	0	(249)	0	746	870
6										
7	Overheads Change - Income Tax Refund	#17995	(278)	0	0	0	138	0	(140)	(209)
8	CIAOC Software Tax Savings/OH Change	#17995	(1,615)	0	0	0	808	0	(807)	(1,211)
9	Bad Debt Allowance for Rates 14 & 14A	#17949	36	32	(11)	21	0	0	57	46
10	Other Post Employment Benefits	#17991/17993	(16,444)	(5,634)	1,859	(3,775)	0	0	(20,219)	(18,332)
11										
12	Deferred 2000 SCP Cost of Service	#17997	126	0	0	0	(64)	0	62	94
13										
14	SCP Net Mitigation Revenues	#17912	(776)	(3,679)	1,214	(2,465)	484	0	(2,757)	(1,767)
15	SCP West to East Transmission	#17913	495	0	0	0	(306)	0	189	342
16	SCP PG&E Contract Cancellation	#17936	2,650	0	0	0	(662)	0	1,988	2,319
17	SCP Provincial Sales Tax Reassessment		0	10,000	0	10,000	0	0	10,000	5,000
18										
19	CCT Deferral	#17924	(265)	0	0	0	133	0	(133)	(199)
20	CCT Assessment	#17929	247	247	(82)	165	(251)	0	161	204
21										
22	Pension Variance	#17946	232	(2,766)	913	(1,853)	24	0	(1,597)	(682)
23	Insurance Variance	#17947	(284)	(259)	85	(174)	263	0	(195)	(240)
24										
25	BCUC Levies	#18149	117	(371)	122	(249)	(108)	0	(240)	(61)
26	OSC Certification Compliance	#18148	4	182	(60)	122	(250)	0	(123)	(59)
27										
28	2006 LCT Elimination	#18502	0	(3,103)	0	(3,103)	0	0	(3,103)	(1,552)
29										
30	Total Deferred Charges for Rate Base		($7,786)	($49,079)	$18,470	($30,610)	$1,750	$11,112	($25,534)	($16,660)

TERASEN GAS INC.

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Cash Working Capital					
2	Cash Required for					
3	Operating Expenses (incl TGS)	($21,047)	($16,420)	($16,403)	$4,644	
4						
5	Customer Deposits - TGI	(2,712)	(2,796)	(2,796)	(84)	
6	Customer Deposits - TGS		(678)	(678)	(678)	
7						
8	Less - Funds Available:					
9						
10	Reserve for Bad Debts - TGI	(3,070)	(2,890)	(2,890)	180	
11	Reserve for Bad Debts - TGS		(14)	(14)	(14)	
12						
13	Withholdings From Employees	(2,221)	(2,416)	(2,416)	(195)	
14						
15	Subtotal	(29,050)	(25,214)	(25,197)	3,853	- Tab A-1, Page 6
16						
17	Other Working Capital Items - TGI					
18	Inventories	6,371	6,296	6,296	(75)	
19	Transmission Line Pack Gas	5,055	3,199	3,199	(1,856)	
20	Gas in Storage	182,935	134,437	134,437	(48,498)	
21						
22	Other Working Capital Items - TGS		50	50	50	
23	Subtotal	194,361	143,982	143,982	(50,379)	- Tab A-1, Page 6
24						
25	Total	$165,311	$118,768	$118,785	($46,526)	

ACCUMULATED DEPRECIATION
FOR THE YEARS ENDING DECEMBER 31, 2006 - 2007
($000)

Line No.	Particulars	Projection 2006	Forecast 2007	Reference
	(1)	(2)	(3)	(4)
1	Balance, Beginning	$670,342	$709,703 *	- Tab A-3, Page 15.3
2				
3	CIAOC Amortization Balance, Beginning	(44,729)	(35,848) *	- Tab A-3, Page 9
4				
5	Gas Plant Held for Future Use			
6	Balance, Beginning	-	-	
7				
8	Retirement Work in Progress	-	-	
9				
10	Utility Accumulated Depreciation			
11	Balance, Beginning	625,613	673,855	- Tab A-3, Page 10
12				
13	Depreciation Provision			
14	Total Plant	94,006	92,184	- Tab A-3, Page 15.3
15	Less - Gas Plant Held for Future Use	-	-	
16	Less Prior Year Adjustments			
17	Less - Amortization of Contributions in			
18	Aid of Construction	(8,362)	(4,758)	- Tab A-3, Page 9
19				
20		85,644	87,426	
21				
22	Plant Retirements	(56,701)	(32,918)	- Tab A-3, Page 15.3
23				
24	CIAOC Retirements	17,309	15,864	- Tab A-3, Page 9
25				
26	Removal Costs	-	-	
27				
28	Proceeds on Disposals	-	-	
29				
30		(39,392)	(17,054)	
31				
32	Balance, Ending	$671,865	$744,227	- Tab A-1, Page 6

* TGI and TGS amalgamation on January 1, 2007.

TERASEN GAS INC.

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Account	Balance 12/31/2006	Annual Depreciation Rate %	Provision 2007 (Cr.)	TGS Adjustment	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2006	Accumulated 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Adjusted for TGS							Adjusted for TGS	
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	886	1.00%	9	0	0	0	0	273	282
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	347	354
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	47	48
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	28	29
7	402-00 Other Intangible Plant - Lease	772	Lease	1	0	0	0	0	115	116
8		2,548		19	0	0	0	0	810	829
9										
10	GAS PLANT HELD FOR FUTURE USE									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	MANUFACTURED GAS / LOCAL STORAGE PLANT									
21	430 Manufact'd Gas - Land	31	0.00%	0	0	0	0	0	0	0
22	432 Manufact'd Gas - Struct. & Improvements									
23	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
24	- Masonry Buildings	438	1.50%	7	0	0	0	0	84	91
25	433 Manufacturing Equipment	139	3.00%	4	0	0	0	0	37	41
26	434 Gas Holders - Manufacturing	358	2.00%	7	0	0	0	0	151	158
27	436 Compressor Equipment	53	3.00%	2	0	0	0	0	20	22
28	437 Measuring & Regulating	309	3.00%	9	0	0	0	0	123	132
29	440/441 Land in Fee Simple and Land Rights	927	0.00%	0	0	0	0	0	1	1
30	442-00 Structures and Improvements	5,455	4.00%	218	0	0	0	0	1,870	2,088
31	443-00 Gas Holders Storage	17,958	4.00%	718	0	0	0	0	7,868	8,586
32	449-00 Local Storage Equipment	16,734	4.00%	669	0	0	0	0	7,757	8,426
33		42,402		1,634	0	0	0	0	17,911	19,545

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Account	Balance 12/31/2006	Annual Depreciation Rate %	Provision 2007 (Cr.)	Provision Adjust-ments	Provision Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2006	Accumulated 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Adjusted for TGS							Adjusted for TGS	
1	TRANSMISSION PLANT									
2	461 Land Rights - Byron Creek	$16	5.00%	$1	$0	$0	$0	$0	$17	$18
3	460-00 / 461-00 Land / Land Rights	49,559	0.00%	0	0	0	0	0	(1,035)	(1,035)
4	462-00 Structures and Improvements - Compressor Stn	15,593	3.00%	468	0	0	0	0	3,989	4,457
5	463-00 Measuring & Regulating	4,363	3.00%	131	0	0	0	0	1,036	1,167
6	464-00 Other Structures - Frame Buildings	4,881	3.00%	146	0	0	0	0	804	950
7	465-00 Mains & Crossings	707,388	2.00%	14,148	0	(167)	0	0	149,890	163,871
8	465-00 Mains & Crossings - Byron Creek	702	5.00%	35	0	0	0	0	723	758
9	466-00 Compressor Equipment	103,977	3.00%	3,119	0	0	0	0	25,632	28,751
10	467-00 Measuring & Regulating	43,736	3.00%	1,312	0	0	0	0	6,614	7,926
11	467-10 Telemetering	5,995	10.00%	600	0	0	0	0	5,823	6,423
12	468-00 Communications Structures & Equip.	2,399	10.00%	240	0	0	0	0	383	623
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		938,609		20,200	0	(167)	0	0	193,876	213,909
15										
16	DISTRIBUTION PLANT									
17	470 Land	3,249	0.00%	0	0	0	0	0	35	35
18	471 Land Rights	803	0.00%	0	0	0	0	0	0	0
19	471 Land Rights - Byron Creek	1	5.00%	0	0	0	0	0	3	3
20	472-00 Structures & Improvements									
21	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
22	-Frame Buildings	8,005	3.00%	240	0	0	0	0	2,075	2,315
23	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
24	-Byron Creek	2	5.00%	0	0	0	0	0	2	2
25	473-00 Services	583,941	2.00%	11,679	0	(3,836)	0	0	94,830	102,673
26	474-00 House Regulator & Meter Installation	158,166	3.57%	5,647	0	(496)	0	0	32,649	37,800
27	475-00 Mains	798,489	2.00%	15,970	0	(3,442)	0	0	196,427	208,955
28	476-00 Compressed Natural Gas									
29										
30	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
31	-All Other	575	6.67%	38	0	0	0	0	288	326
32	477-00 Measuring & Regulating	81,544	3.00%	2,446	0	(524)	0	0	9,731	11,653
33	477-10 Telemetering	5,316	10.00%	532	0	0	0	0	4,855	5,387
34	477-00 Measuring & Regulating - Byron Creek	163	5.00%	8	0	0	0	0	(51)	(43)
35	478 Meters	218,947	3.57%	7,816	0	(818)	0	0	46,071	53,069
36	479 Other Distribution Equipment	26	4.00%	1	0	0	0	0	26	27
37		1,859,227		44,377	0	(9,116)	0	0	386,941	422,202

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Account	Balance 12/31/2006	Annual Depreciation Rate %	Provision 2007 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2006	Accumulated 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Adjusted for TGS							Adjusted for TGS	
1	GENERAL PLANT									
2	470 Land	$20,995	$0	$0	$0	$0	$0	$0	17	17
3	482-00 Structures & Improvements									
4	-Leasehold Alterations	4,086	Term - Lease	540	0	0	0	0	13,945	14,485
5	-Masonry Buildings	75,217	1.50%	1,128	0	0	0	0	(7,877)	(6,749)
6	-Frame Buildings	5,071	3.00%	152	0	0	0	0	(3,086)	(2,934)
7	483-00 Office Furniture & Equipment									
8	-Furniture & Equipment	24,261	5.00%	1,213	0	(78)	0	0	10,898	12,033
9	-Computers - Hardware	29,796	20.00%	5,959	0	(7,999)	0	0	19,999	17,959
10										
11	-Computer Software - Non-Infrastructure	23,336	20.00%	4,667	0	(7,208)	0	0	20,696	18,155
12	-Computer Software - Infrastructure/Custom	73,914	12.50%	9,239	0	(7,636)	0	0	32,569	34,172
13										
14	484-00 Transportation Equipment	801	15.00%	120	0	0	0	0	2,842	2,962
15	485-00 Maintenance & Repair Equipment	283	5.00%	14	0	0	0	0	(374)	(360)
16	486-00 Tools & Work Equipment	31,404	5.00%	1,570	0	(167)	0	0	12,347	13,750
17	487-00 Equipment on Customers' Premises	1,230	5.00%	62	0	0	0	0	799	861
18	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
19	487-XX - VRA Compressor Installation Cost	583	33.33%	194	0	0	0	0	886	1,080
20	488-00 Communication - Structures & Equip.	11,171	5.00%	559	0	(547)	0	0	2,394	2,406
21	488-00 Communication - Radios	5,372	10.00%	537	0	0	0	0	4,107	4,644
22	489-00 Other General Equipment	2	5.00%	0	0	0	0	0	3	3
23		307,522		25,954	0	(23,635)	0	0	110,165	112,484
24										
25	UNCLASSIFIED PLANT									
26	498-00 O&M Expense Charged to Construction	153	0.00%	0	0	0	0	0	0	0
27										
28	TOTAL	$3,150,461		$92,184	$0	($32,918)	$0	$0	$709,703	$768,969
29										
30	Less - Capitalization Policy Change	0	0.00%	0	0	0	0	0	0	0
31	Add - Accounting Change Phase-In	0	0.00%	0	0	0	0	0	0	0
32										
33	TOTALS	$3,150,461		$92,184	$0	($32,918)	$0	$0	$709,703	$768,969

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Account	Balance 12/31/2005	Annual Depreciation Rate %	Provision 2006 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2005	Accumulated 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	47	48
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	340	347
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	46	47
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	27	28
7	402-00 Other Intangible Plant - Lease	772	Lease	0	0	0	0	0	115	115
8		1,771		10	0	0	0	0	575	585
9										
10	GAS PLANT HELD FOR FUTURE USE									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	MANUFACTURED GAS / LOCAL STORAGE PLANT									
21	430 Manufact'd Gas - Land	31	0.00%	0	0	0	0	0	0	0
22	432 Manufact'd Gas - Struct. & Improvements									
23	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
24	- Masonry Buildings	438	1.50%	7	0	0	0	0	77	84
25	433 Manufacturing Equipment	139	3.00%	4	0	0	0	0	33	37
26	434 Gas Holders - Manufacturing	358	2.00%	7	0	0	0	0	144	151
27	436 Compressor Equipment	53	3.00%	2	0	0	0	0	18	20
28	437 Measuring & Regulating	309	3.00%	9	0	0	0	0	114	123
29	440/441 Land in Fee Simple and Land Rights	927	0.00%	0	0	0	0	0	1	1
30	442-00 Structures and Improvements	5,455	4.00%	218	0	0	0	0	1,652	1,870
31	443-00 Gas Holders Storage	17,358	4.00%	694	0	0	0	0	7,174	7,868
32	449-00 Local Storage Equipment	16,734	4.00%	669	0	0	0	0	7,088	7,757
33		41,802		1,610	0	0	0	0	16,301	17,911

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Account	Balance 12/31/2005	Annual Depreciation Rate %	Provision 2006 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2005	Accumulated 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	TRANSMISSION PLANT									
2	461 Land Rights - Byron Creek	$16	5.00%	$1	$0	$0	$0	$0	$16	$17
3	460-00 / 461-00 Land / Land Rights	48,235	0.00%	0	0	0	0	0	(1,035)	(1,035)
4	462-00 Structures and Improvements - Compressor	15,183	3.00%	455	0	0	0	0	3,534	3,989
5	463-00 Measuring & Regulating	4,363	3.00%	131	0	0	0	0	905	1,036
6	464-00 Other Structures - Frame Buildings	4,881	3.00%	146	0	0	0	0	658	804
7	465-00 Mains & Crossings	704,281	2.00%	14,086	0	(164)	0	0	135,968	149,890
8	465-00 Mains & Crossings - Byron Creek	702	5.00%	35	0	0	0	0	688	723
9	466-00 Compressor Equipment	103,928	3.00%	3,118	0	0	0	0	22,514	25,632
10	467-00 Measuring & Regulating	38,296	3.00%	1,149	0	0	0	0	5,465	6,614
11	467-10 Telemetering	5,995	10.00%	600	0	0	0	0	5,223	5,823
12	468-00 Communications Structures & Equip.	1,701	10.00%	170	0	0	0	0	213	383
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		927,581		19,891	0	(164)	0	0	174,149	193,876
15										
16	DISTRIBUTION PLANT									
17	470 Land	3,249	0.00%	0	0	0	0	0	35	35
18	471 Land Rights	678	0.00%	0	0	0	0	0	0	0
19	471 Land Rights - Byron Creek	1	5.00%	0	0	0	0	0	3	3
20	472-00 Structures & Improvements									
21	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
22	-Frame Buildings	7,395	3.00%	222	0	0	0	0	1,776	1,998
23	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
24	-Byron Creek	2	5.00%	0	0	0	0	0	2	2
25	473-00 Services	560,956	2.00%	11,219	0	(3,670)	0	0	86,966	94,515
26	474-00 House Regulator & Meter Installation	148,700	3.57%	5,309	0	(483)	0	0	27,721	32,547
27	475-00 Mains	763,945	2.00%	15,279	0	(3,339)	0	0	183,532	195,472
28	476-00 Compressed Natural Gas									
29										
30	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
31	-All Other	575	6.67%	38	0	0	0	0	250	288
32	477-00 Measuring & Regulating	71,686	3.00%	2,151	0	(514)	0	0	8,062	9,699
33	477-10 Telemetering	5,316	10.00%	532	0	0	0	0	4,323	4,855
34	477-00 Measuring & Regulating - Byron Creek	163	5.00%	8	0	0	0	0	(59)	(51)
35	478 Meters	203,520	3.57%	7,266	0	(797)	0	0	39,576	46,045
36	479 Other Distribution Equipment	0	4.00%	0	0	0	0	0	0	0
37		1,766,186		42,024	0	(8,803)	0	0	352,187	385,408

TERASEN GAS INC.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Account	Balance 12/31/2005	Annual Depreciation Rate %	Provision 2006 (Cr.)	Adjust- ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2005	Accumulated 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	GENERAL PLANT									
2	480 Land	$20,962	$0	$0	$0	$0	$0	$0	$17	$17
3	482-00 Structures & Improvements									
4	-Leasehold Alterations	4,086	Term - Lease	540	0	0	0	0	13,391	13,931
5	-Masonry Buildings	74,722	1.50%	1,121	0	(180)	0	0	(8,818)	(7,877)
6	-Frame Buildings	5,071	3.00%	152	0	0	0	0	(3,238)	(3,086)
7	483-00 Office Furniture & Equipment									
8	-Furniture & Equipment	23,803	5.00%	1,190	0	(48)	0	0	9,751	10,893
9	-Computers - Hardware	28,951	20.00%	5,790	0	(5,917)	0	0	20,021	19,894
10										
11	-Computer Software - Non-Infrastructure	34,648	20.00%	6,930	0	(13,803)	0	0	27,569	20,696
12	-Computer Software - Infrastructure/Custom	94,966	12.50%	11,871	0	(27,351)	0	0	48,047	32,567
13										
14	484-00 Transportation Equipment	623	15.00%	93	0	(7)	0	0	2,630	2,716
15	485-00 Maintenance & Repair Equipment	366	5.00%	18	0	(83)	0	0	(309)	(374)
16	486-00 Tools & Work Equipment	29,239	5.00%	1,462	0	(167)	0	0	11,028	12,323
17	487-00 Equipment on Customers' Premises	1,230	5.00%	62	0	0	0	0	737	799
18	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
19	487-XX - VRA Compressor Installation Cost	583	33.33%	194	0	0	0	0	692	886
20	488-00 Communication - Structures & Equip.	10,221	5.00%	511	0	(178)	0	0	2,047	2,380
21	488-00 Communication - Radios	5,372	10.00%	537	0	0	0	0	3,565	4,102
22	489-00 Other General Equipment	0	5.00%	0	0	0	0	0	0	0
23		334,843		30,471	0	(47,734)	0	0	127,130	109,867
24										
25	UNCLASSIFIED PLANT									
26	499 Plant Suspense	153	0.00%	0	0	0	0	0	0	0
27										
28	TOTAL	$3,072,336		$94,006	$0	($56,701)	$0	$0	$670,342	$707,647
29										
30	Less - Capitalization Policy Change	0	2.27%	0	0	0	0	0	0	0
31	Add - Accounting Change Phase-In	0	2.27%	0	0	0	0	0	0	0
32										
	TOTALS	$3,072,336		$94,006	$0	($56,701)	$0	$0	$670,342	$707,647

TERASEN GAS INC.

2006 ANNUAL REVIEW
2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

REVISED FORECASTS AND PROJECTIONS FOR 2007 REVENUE REQUIREMENTS AND OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-4 INDEX

GAS SALES AND TRANSPORTATION VOLUMES

This Section addresses the forecast of gas sales and transportation volumes for 2007. Included in this Section is a review of the energy forecast methodology, as well as factors influencing customer additions and use per customer. An outline of the residential, commercial and industrial margins and revenues over the forecast period is also provided.

The yearly projections and forecasts, including customer accounts and the use per account used to derive revenues for 2007, reflect the best information available at the time of the Annual Review.

Squamish customers are included in the 2007 Forecast as TGS will be amalgamating with TGI effective January 1, 2007.

The forecast of industrial accounts and associated volumes are updated to reflect the latest industrial survey conducted during the summer of 2006. Similarly, revenue and margin forecasts reflect the most recently approved rates.

1. FORECAST METHODOLOGY

Consistent with previous years, the forecasting process is comprised of three main components:

- the customer additions forecast;
- the average use per customer forecast; and
- the industrial forecast.

The residential and commercial energy forecast consisting of Rate Classes 1, 2, 3 and 23 is driven by the respective account and use per customer forecasts, while the industrial energy forecast incorporates Rate Classes 7, 22, 25 and 27 and is based mainly on customer survey data. Rate Classes 4, 5 & 6 account and demand growth is modelled from market information and historical trends.

The customer additions forecast reflects prevailing macroeconomic circumstances affecting residential and commercial customers. The forecast for industrial customers assumes no net change in the number of customers over the forecast period except where written requests for change of service have been received by Terasen Gas.

Consistent with the methodology used in prior years, the average use per customer is estimated for Rate Classes 1, 2, 3 and 23 and is multiplied by the corresponding forecast of customers in each respective rate class to derive energy consumption. The large volume industrial and transportation customer throughput forecast continues to rely on historical data, sector analyses and customer-specific survey results.

Current rates are applied against the energy forecast to calculate the revenue forecast. The underlying assumptions and components of that forecast are discussed below.

2. UNDERLYING ASSUMPTIONS

The following assumptions were made about external influences when developing this forecast:

- province will continue to experience strong economic growth for the balance of 2006 and 2007;
- provincial population growth continues, with significant contributions from international immigration and inter-provincial migration;
- natural gas commodity prices will moderate from levels experienced in 2005 but will continue to remain high relative to historical levels;
- no change to provincial electricity pricing methodologies;
- natural gas will continue to face competitive challenges compared to electricity and to some degree to alternative energy options;
- energy efficiency will continue to improve driven by appliance renewal and continuing conservation efforts; and
- industrial and transportation sectors will experience limited growth, but much of the growth in natural gas volumes will be offset by switching to alternative fuels and improved energy efficiency.

3. ECONOMIC OUTLOOK FOR BRITISH COLUMBIA

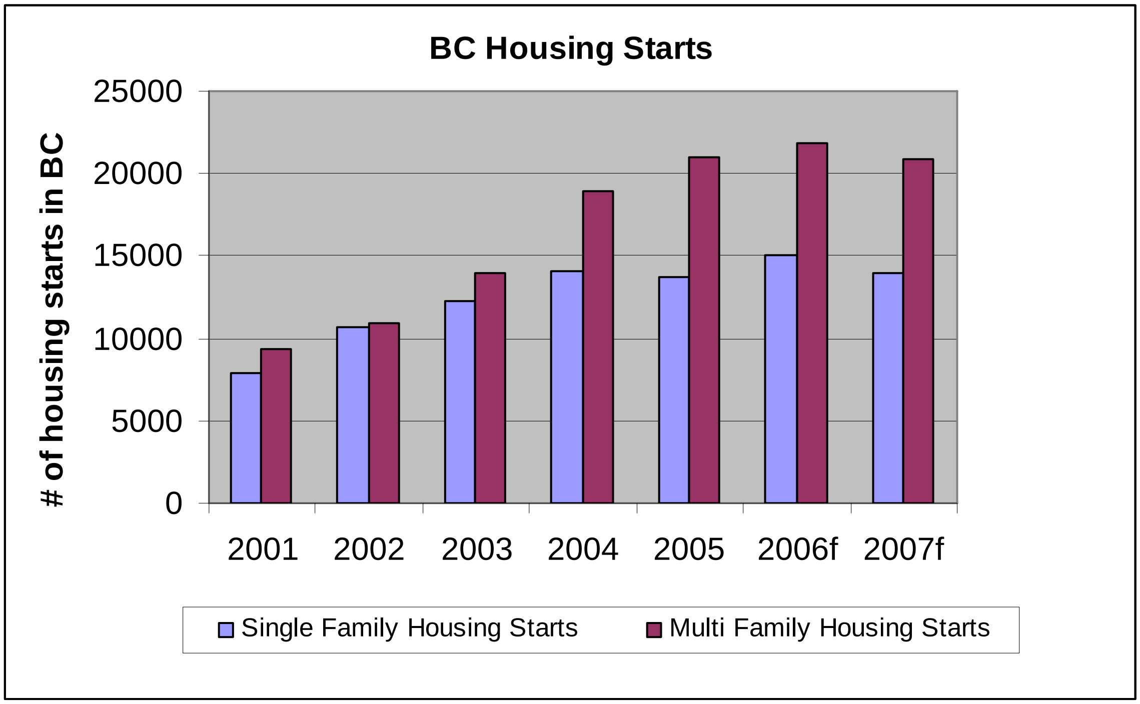
The prospects for the province remain positive for the end of 2006 and into 2007. The consensus among leading economists[1] is that the country will continue to experience growth with British Colombia being among the leading provinces. Though there is acknowledgement that the U.S. economy will slow in 2007 - due in part to a drop in real estate values - none of the economists are calling for a recession. Rather, a slower rate of growth in the U.S. is foreseen which is expected to allow for a decrease in interest rates later in 2007. It is expected that Canada will fare better than its U.S. counterpart due to strong internal consumer demand, elevated commodity prices and spending by business on capital items due to a strong Canadian dollar. The forecast for British Columbia builds on Canada's strengths and adds to it spending by government on major infrastructure projects, low unemployment and continued strength in housing demand.

Housing Market

New home construction in BC is in its sixth consecutive year of growth, marking the longest up-swing since the 1985-1989 expansion and the most consecutive years of growth on record. However, this growth is expected to decline slightly in 2007 from levels experienced in 2006. According to the Canada Mortgage and Housing Corporation (CMHC), the provincial housing sector will benefit from above-average economic growth of 3.5% this year and next. Investment and consumer spending will continue to be the key drivers of growth. High commodity prices will continue to generate jobs and income growth, which will in turn draw people from other countries and provinces. These fundamentals, coupled with high consumer confidence and relatively low mortgage rates, will continue to fuel housing demand.

As of June 2006, single detached housing starts rose 27% to 7,580 units, compared to June 2005. Multiple home starts rose 9 per cent to 10,264 units, compared to June last year.

[1] **BMO Financial Group** – North American Outlook, Aug. 2006; Provincial Outlook, Jul. 17, 2006; **Conference Board of Canada** - Provincial Outlook, Summer 2006; **RBC Financial Group** - Provincial Outlook, June 2006; Economic & Financial Market Outlook, June 2006; **TD Bank Financial Group** – TD Quarterly Economic Forecast, Sept 18, 2006



2005 Actual (CMHC Housing Now - BC 2005 Fourth Quarter Highlights)
2006f and 2007f (CMHC Housing Market Outlook - Canada - Third Quarter 2006)

The latest CMHC housing starts forecast for BC published in the third quarter of 2006 projects 37,000 housing starts for 2006 (a 6.7% increase from last year) and 34,900 for 2007 (a 5.7% decrease from 2006). Multi-Family Dwelling (MFD) starts will reach an eleven-year high of 21,900 units in 2006 as demand for this type of housing continues. Nearly three quarters of these MFD starts will be apartments reflecting rising land costs.

Customer Additions Forecast

The customer addition forecast is derived from broad regional economic forecasts and end-use information. Inputs gathered through industrial associations, research institutes, government agencies and periodic surveys provide the basis for relating economic data to account growth. To forecast residential account additions, actual household formation, estimated market share and historical commodity price are statistically linked with actual account additions to model annual account growth on a service area basis. Household formation and commodity price forecasts are then applied to obtain the expected number of additions, adjusted for actual customer counts to date (June 2006). For the forecast produced in support of the 2006 Annual Review, the BC Statistics 2006 Household Formation Forecast is used as the primary predictor variable to estimate household formations by area over the forecast period, with the near-term forecast validated by current housing start and service request information.

The housing boom sparked by low mortgage rates and strong consumer confidence has added new customer additions at rates somewhat higher than those anticipated in prior forecasts. Although mortgage rates have begun to rise slowly, a very active resale market together with continued population and employment growth are expected to maintain the current boom for the balance of this year and through 2007.

The table below provides a summary of the Residential, Commercial and Industrial & Transportation customer additions for the last 3 years and a projection for the years 2006 and 2007. Yearly information on housing starts and population growth is also provided.

TGI Customer Growth[1]

	2003 Actuals	2004 Actuals	2005 Actuals	2006 Projected	2007 Forecast
Residential[2]	6,306	10,716	11,427	12,280	12,764
Commercial[3]	(762)	756	849	433	235
Industrial & Transportation[4]	2	32	69	13	146
Squamish					240
Total	**5,546**	**11,504**	**12,345**	**12,726**	**13,385**
Year-Ending Customers	775,516	787,020	799,365	812,091	828,700 [7]
Housing Starts[5]	26,174	32,925	34,667	37,000	34,900
Population Growth[6]	1.0%	1.1%	1.3%	1.1%	1.3%

Notes
1. Includes Lower Mainland, Inland, Columbia and Revelstoke service regions only.
2. Rate 1
3. Rates 2, 3 & 23
4. Rates 4, 5, 6, 7, 22, 25 & 27
5. Source: CMHC - Housing Market Outlook (Q2 2006) & CHS Residential Building Activity (April 2006).
6. Source: BC Stats - Provincial Population Projection (P.E.O.P.L.E. 31).
7. Includes 2006 Year-Ending Customer balance for Squamish of 3,224

Even though the CMHC estimate of new housing starts is projected to moderate in 2007, the forecast above reflects a slight increase in customer additions for 2007. There is a time lag between the start of construction (especially for larger MFD developments) and attachment to natural gas service. As such, some of the housing starts forecasted by CMHC will not materialize as new customer additions until 2007. Also, TGI continues to focus on educating existing and prospective customers as to the economic benefits of natural gas for space and water heating relative to other energy sources as well as offer programs to encourage natural gas use.

Finally, natural gas prices have been decreasing over 2006 and the outlook is for prices to stabilize provided there are no significant weather events that threaten supply. Net account additions for 2007 should benefit from lower natural gas prices as compared to the price spikes customers experienced in 2005.

4. USE PER CUSTOMER FORECAST

Individual use per customer projections are developed for each service area and rate class by considering the following factors:

- recent historical normalized use per account;
- efficiency improvements - appliance and insulation upgrades;
- customer migration between rate classes;
- demand side management programs effects; and
- customer reaction to changes in natural gas prices.

In response to changes in customer lifestyle and the provincial demographic profile, TGI expects the proportion of MFDs to continue growing slightly over the next several years. Homeowners' shift toward apartment-style condominiums and townhouses continues to place downward pressure on residential use rates. Other factors causing downward pressure on use rates include space heating efficiency, improved home insulation and setback thermostats.

In spite of the long-term trend of decreasing use rates for residential customers, the forecast calls for a rebound in the 2006 use per customer rates as compared to 2005 when natural gas prices increased sharply. Preliminary data (normalized for weather) for the first half of 2006 is suggesting that residential use rates will come in above those recorded in 2005. This projected outcome is similar to what was experienced in 2002 when residential use rates rose significantly after a sharp drop in 2001 triggered by a spike in natural gas prices during that year. Use per customer rates are then forecasted to decline in 2007 similar to the decrease seen in prior years for which there were no price spikes.

A summary of historic and forecasted use per customer rates are set out below and have been used in the preparation of the 2007 forecast.

Historic and Forecast Usage - Rates 1, 2, 3 & 23 (GJ)

	Normal 2003	Normal 2004	Normal 2005	Projected 2006	Forecast 2007
Rate 1	103.1	102.6	97.4	100.3	99.8
Rate 2	303.6	313.8	305.8	318.1	314.2
Rate 3	3,292.0	3,500.9	3,387.6	3,462.8	3,393.7
Rate 23	4,883.4	5,112.6	4,714.3	4,775.2	4,796.4

5. ENERGY FORECAST

a. Residential and Commercial

The residential and commercial energy forecast is calculated by multiplying the use per customer rate by the total number of customers. Compared with the projection for 2006, the total residential energy consumption is expected to rise from 70.5 to 73.6 PJs in 2007 while commercial consumption is forecast to increase from 43.8 to 44.3 PJs. Lower projected consumption for 2006, with respect to 2007, is primarily caused by the effect of warmer than normal weather experienced over the first 6 months of this year – the energy forecast projections for 2006 are based on 6 months of actual data (not normalized for weather) and 6 months of forecasted data while other years (i.e. ’03 to ’05 & ’07) contain 12 months of normalized data. The forecast for each year is provided in the summary table at the end of this section.

b. Firm Sales and Industrial

As with previous years, the primary source of information for the industrial energy forecast was the industrial survey which was conducted over the summer of 2006. Surveys were faxed to each customer in Rate Classes 7, 22, 25 and 27. Customers were asked to what extent they expected their firm’s natural gas consumption to change from the previous year and to estimate their consumption over the forecast period. The industrial energy forecast was then updated to include these demand estimates and other pertinent feedback.

A total of 353 surveys were completed, representing a response rate of 71% (based on 2005 energy consumption) and 46% (based on the number of accounts). Surveys were gathered from customers across every service region, rate class and industry.

Rate Classes 4, 5 & 6 forecasted volumes are estimated based on the most recent 12 months (July 2005 – June 2006) of metered consumption data. Where statistically acceptable, the forecast consumption for Rate Class 5 was adjusted to reflect a normal weather year.

Total Firm Sales and Industrial energy consumption (excluding Burrard Thermal and TGVI) is expected to decrease from 60.9 PJs in 2006 to 60.4 PJs in 2007. The increase in natural gas prices in 2005 caused some industrial customer to switch to other fuels, but this reaction has abated in 2006 as a result of a decrease in natural gas prices. The small decrease forecasted for 2007 is primarily attributable to the closure of specific industrial accounts.

The following table sets out the energy forecast by Residential, Commercial, Firm Sales, and Industrial customers.

Historic and Forecast Energy (PJ)

	Normal 2003	Normal 2004	Normal 2005	Projected 2006	Forecast 2007
Residential[1]	72.6	72.0	69.3	70.5	73.6
Commercial[2]	45.3	45.2	43.9	43.8	44.3
Firm Sales[3]	6.1	5.3	4.7	4.3	4.1
Industrial[4]	58.8	58.3	58.6	56.6	56.3
Squamish					0.4
Total	**182.8**	**180.8**	**176.5**	**175.2**	**178.8**

Notes
1. Rate 1
2. Rates 2, 3 & 23
3. Rates 4, 5 & 6
4. Rates 7, 22, 25 & 27 (does not include Burrard Thermal & TGVI)

6. REVENUE FORECAST

A revenue forecast for each customer rate class is developed from the total energy forecasts and the applicable rates. The revenue forecast below does not include amounts for Burrard Thermal and TGVI.

The table below summarizes historical and forecast revenues for 2003 to 2007 by customer category.

Historic and Forecast Revenue ($ million)

	Normal 2003	Normal 2004	Normal 2005	Projected 2006	Forecast 2007
Residential[1]	784.3	815.0	864.5	933.0	911.0
Commercial[2]	411.2	421.1	446.9	473.5	446.3
Firm Sales[3]	51.8	47.6	46.7	45.9	41.8
Industrial[4]	44.7	47.1	49.6	51.8	51.8
Squamish					4.6
Total	**1,292.0**	**1,330.8**	**1,407.7**	**1,504.2**	**1,455.5**

Notes
1. Rate 1
2. Rates 2, 3 & 23
3. Rates 4, 5 & 6
4. Rates 7, 22, 25 & 27 (does not include Burrard Thermal & TGVI)

7. MARGIN FORECAST

In 2006 and 2007, total margin is expected to increase driven by approved rate increases, forecast customer growth and a rebound in use rates from 2005 levels. The table below sets out the forecast for Residential, Commercial, Firm Sales and Industrial customers.

Historic and Forecast Margin ($ million)

	Normal 2003	Normal 2004	Normal 2005	Projected 2006	Forecast 2007
Residential[1]	273.2	284.2	277.0	293.2	302.6
Commercial[2]	118.8	123.4	120.4	125.5	126.6
Firm Sales[3]	10.5	10.9	9.4	8.8	8.6
Industrial[4]	43.5	45.4	48.5	49.5	50.1
Squamish					1.5
Total	**446.0**	**463.9**	**455.3**	**477.0**	**489.4**

Notes
1. Rate 1
2. Rates 2, 3 & 23
3. Rates 4, 5 & 6
4. Rates 7, 22, 25 & 27 (does not include Burrard Thermal & TGVI)

8. SOUTHERN CROSSING PIPELINE (SCP) THIRD PARTY REVENUES

For 2007, SCP Third Party firm revenues are forecasted to be $11.1 million which is relatively unchanged from 2006. The revenue forecast for SCP is detailed in the table below.

2007 SCP Revenues

Northwest Natural Gas Co.	$	7,297,102
PG&E Termination	$	(825,000)
MCRA	$	3,600,000
Net Mitigation	$	1,000,000
Total SCP Revenues	**$**	**11,072,102**

Debits from the Midstream Cost Reconciliation Account (MCRA) are expected to continue until November 1, 2010. PG&E Termination fees to PG&E are planned to decrease in 2010 to $145,000 per year and cease at the end of 2018. Net mitigation revenues continue to be forecasted at $1 million per year.

9. MISCELLANEOUS REVENUE

Revenue from service work remains at $85 for customer additions and $25 for account transfers. Late Payment Charges are calculated using the O&M formula methodology as set out in the 2004–2007 Negotiated Settlement document. Annual NSF cheques are estimated at approximately 1% of the beginning of year account base at a rate of $20 per cheque.

Other miscellaneous revenue is estimated at approximately $0.1 million comprising of Non-Regulated Businesses (NRB) recoveries.

10. BURRARD THERMAL REVENUE

Various Burrard Thermal agreements, including the Bypass Transportation Agreement, are forecasted to provide $9.9 million in revenues in 2007. The transportation charge is fixed and independent of energy consumption.

11. TERASEN GAS (VANCOUVER ISLAND) INC. REVENUE

Revenue from wheeling demand charges and odorant cost recovery remains at approximately $4.1 million for 2007.

12. FORECAST RISKS

Although the economic fundamentals that underpin the forecast for 2007 are stronger than they have been in the recent past, a number of risks are present that could affect actual performance over the near term. These risks include but are not limited to:

- an increase in interest rates and a slow-down in new construction;
- rising construction costs and a shortage of skilled trades workers;
- a stronger Canadian dollar and a decrease in the competitiveness of the export market - especially as it affects the forestry industry;
- natural gas price increases impacting its competitive position; and

- a greater than anticipated slowdown in the U.S. economy that spills over into Canada.

13. SUMMARY

The updated Year-End Forecast for 2006 reflects the best currently available information, and incorporates the following changes since the 2006 Forecast was completed:

- Revenues adjusted to reflect current rates including all approved 2006 permanent delivery rates and gas cost increases; and
- Customer counts adjusted to reflect actual results to June 2006.

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2007

Line No.	Particulars	2006 Approved	2007 Terajoules Core and Non-Core	2007 Terajoules Bypass and Special Rates	2007 Terajoules Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(6)
1	SALES						
2	Schedule 1 - Residential	72,934.4	73,565.4	0.0	73,565.4	631.0	
3	Schedule 2 - Small Commercial	22,333.4	23,129.9	0.0	23,129.9	796.5	
4	Schedule 3 - Large Commercial	16,273.6	15,516.2	0.0	15,516.2	(757.4)	
5							
6	Total Schedules 1, 2 and 3	111,541.4	112,211.5	0.0	112,211.5	670.1	
7							
8	Schedule 4 - Seasonal Service	120.6	161.3	0.0	161.3	40.7	
9	Schedule 5 - General Firm Service	4,205.8	3,805.0	0.0	3,805.0	(400.8)	
10							
11	Industrials						
12	Schedule 7 - Interruptible	53.9	53.4	0.0	53.4	(0.5)	
13							
14	Schedule 10	0.0	0.0	0.0	0.0	0.0	
15							
16	Total Industrials	53.9	53.4	0.0	53.4	(0.5)	
17							
18	Schedule 6 - N G V Fuel - Stations	217.8	166.2	0.0	166.2	(51.6)	
19							
20	Total Sales - TGI	116,139.5	116,397.4	0.0	116,397.4	257.9	- Tab A-1, Page 7
21							
22	TRANSPORTATION SERVICE						
23	Schedule 22 - Firm Service	23,550.8	10,664.5	11,499.0	22,163.5	(1,387.4)	
24	- Interruptible Service	15,100.5	11,811.7	1,730.3	13,542.0	(1,558.4)	
25	Schedule 23 - Large Commercial	5,185.7	5,672.4	0.0	5,672.4	486.7	
26	Schedule 25 - Firm Service	15,546.4	14,080.0	1,867.9	15,947.9	401.5	
27	Schedule 27 - Interruptible	6,103.0	5,566.2	0.0	5,566.2	(536.8)	
28	Terasen Gas (Vancouver Island)	32,685.0	0.0	32,385.9	32,385.9	(299.1)	
29	Columbia Service Area - Byron Creek	115.9	0.0	119.4	119.4	3.5	
30							
31	Total Transportation Service	98,287.3	47,794.8	47,602.5	95,397.3	(2,890.0)	- Tab A-1, Page 7
32							
33	TOTAL SALES AND TRANSPORTATION SERVICE - TGI	214,426.8	164,192.2	47,602.5	211,794.7	(2,632.1)	- Tab A-1, Page 7
34							
35	TOTAL SALES - TGS		379.0		379.0	379.0	- Tab A-1, Page 7
36							
37	TOTAL SALES AND TRANSPORTATION SERVICE	214,426.8	164,571.2	47,602.5	212,173.7	(2,253.1)	- Tab A-1, Page 7

TERASEN GAS INC. - AMALGAMATED

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Gas Sales Revenue At Existing Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	SALES						
2	Residential / Residential	$1,012,064	$911,046	$0	$911,046	(101,018)	
3	Schedule 2 - Small Commercial	293,147	266,630	0	266,630	(26,517)	
4	Schedule 3 - Large Commercial	197,097	165,515	0	165,515	(31,582)	
5							
6	Total Schedules 1, 2 and 3	1,502,308	1,343,191	0	1,343,191	(159,117)	
7							
8	Schedule 4 - Seasonal Service	1,324	1,520	0	1,520	196	
9	Schedule 5 - General Firm Service	48,195	38,401	0	38,401	(9,794)	
10		49,519	39,921	0	39,921	(9,598)	
11	Industrials						
12	Schedule 7 - Interruptible	596	519	0	519	(77)	
13							
14	Schedule 10	0	0	0	0	0	
15							
16							
17	Total Industrials	596	519	0	519	(77)	
18							
19	Schedule 6 - N G V Fuel - Stations	2,684	1,867	0	1,867	(817)	
20							
21	Total Sales	1,555,107	1,385,498	0	1,385,498	(169,609)	- Tab A-1, Page 7
22							
23	TRANSPORTATION SERVICE						
24	Schedule 22 - Firm Service	18,445	7,610	11,831	19,441	996	
25	- Interruptible Service	11,228	8,811	1,125	9,936	(1,292)	
26	Schedule 23 - Large Commercial	12,391	14,127	0	14,127	1,736	
27	Schedule 25 - Firm Service	22,886	24,479	829	25,308	2,422	
28	Schedule 27 - Interruptible Service	6,362	6,218	0	6,218	(144)	
29	Terasen Gas (Vancouver Island)	0	0	0	0	0	
30	Columbia Service Area - Byron Creek	48	0	50	50	2	
31							
32	Total Transportation Service	71,360	61,245	13,835	75,080	3,720	- Tab A-1, Page 7
33							
34	TOTAL SALES AND TRANSPORTATION SERVICE - TGI	$1,626,467	$1,446,743	$13,835	$1,460,578	($165,889)	
35	TOTAL SALES AND TRANSPORTATION SERVICE - TGS	0	4,603	0	4,603	4,603	- Tab A-1, Page 7
36							
37	TOTAL SALES AND TRANSPORTATION SERVICE	$1,626,467	$1,451,346	$13,835	$1,465,181	($161,286)	- Tab A-1, Page 7

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CORE AND NON-CORE										
2	Core and Non-Core Sales										
3	Schedule 1 - Residential	54,876.7	$8.2750	$454,102	16,950.3	$8.2524	$139,881	1,738.4	$8.3040	$14,436	$608,419
4	Schedule 2 - Small Commercial	16,710.1	8.3030	138,744	5,719.6	8.3273	47,629	700.2	8.3290	5,832	192,205
5	Schedule 3 - Large Commercial	12,827.4	8.1860	105,005	2,455.6	8.3377	20,474	233.2	8.2230	1,918	127,397
6	Schedules 1, 2 and 3	84,414.2		697,851	25,125.5		207,984	2,671.8		22,186	928,021
7											
8	Schedule 4 - Seasonal	80.0	8.0520	644	81.3	8.0170	652.0	0.0	0.0000	0	1,296
9	Schedule 5 - General Firm	3,141.9	8.0520	25,299	604.0	8.0170	4,842	59.1	8.1020	479	30,620
10											
11	Industrial										
12	Interruptible - Schedule 7	37.6	8.0520	303	15.8	8.0170	127	0.0	0.0000	0	430
13	- Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
14	Total Industrials	37.6		303	15.8		127	0.0		0	430
15											
16	N G V Fuel - Stations - Schedule 6	144.0	7.8740	1,134	22.2	7.8570	174	0.0	0.0000	0	1,308
17											
18	Total NGV	144.0		1,134	22.2		174	0.0		0	1,308
19											
20	Total Core and Non-Core Sales	87,817.7		725,231	25,848.8		213,779	2,730.9		22,665	961,675
21											
22	Core and Non-Core Transportation Service										
23	Schedule 22 - Firm Service	1,022.0	0.0091	9	7,383.8	0.0274	203	2,258.7	0.0916	207	419
24											
25	- Interruptible Service	10,979.2	0.0091	100	813.5	0.0274	23	19.0	0.0916	2	125
26											
27	Schedule 23 - Large Commercial	4,641.0	0.0091	42	983.8	0.0274	27	47.6	0.0924	4	73
28	Schedule 25 - Firm Service	9,412.4	0.0091	86	4,229.5	0.0275	117	438.1	0.0915	40	243
29	Schedule 27 - Interruptible Service	4,815.8	0.0091	44	750.4	0.0280	21	0.0	0.0000	0	65
30	Total Core and Non-Core T-Service	30,870.4		281	14,161.0		391	2,763.4		253	925
31											
32	Total Cost of Gas - TGI	118,688.1		$725,512	40,009.8		$214,170	5,494.3		$22,918	$962,600
33	Total Cost of Gas - TGS	379.0		$3,130							$3,130
34											
35	Cost of Gas Sold	119,067.1		$728,642	40,009.8		$214,170	5,494.3		$22,918	$965,730

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000)	Total Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	BYPASS AND SPECIAL RATES										
2	Bypass and Special Rates Sales										
3	Schedule 4 - Seasonal	0.0	$0.0000	$0	0.0	$0.0000	$0	0.0	$0.0000	$0	$0
4											
5	Large Industrial										
6	Interruptible - Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
7											
8											
9	Total Large Industrial	0.0		0.0	0.0		0.0	0.0		0.0	0
10	Total Bypass and Spec. Rates Sales	0.0		0.0	0.0		0.0	0.0		0.0	0
11											
12	Bypass and Special Rates Transportation Service										
13	Schedule 22 - Firm Service	0.0	0.0091	0	10,109.7	0.0274	277	315.6	0.0916	29	306
14											
15	- Interruptible Service	1,730.3	0.0091	16	0.0	0.0274	0	0.0	0.0916	0	16
16											
17	- Burrard Thermal - Firm	1,073.7	0.0229	25	0.0		0	0.0		0	25
18	Schedule 23 - Large Commercial	0.0	0.0091	0	0.0	0.0274	0	0.0	0.0916	0	0
19	Schedule 25 - Firm Service	0.0	0.0091	0	1,867.9	0.0274	51	0.0	0.0916	0	51
20	Schedule 27 - Interruptible Service	0.0	0.0091	0	0.0	0.0274	0	0.0	0.0916	0	0
21	Byron Creek	0.0	0.0000	0	0.0	0.0000	0	119.4	0.0916	11	11
22	Centra BC (PCEC)	32,385.9	0.0229	741							741
23	Total Bypass and Spec. Rates T-Svc	35,189.9		782	11,977.6		328	435.0		40	1,150
24											
25											
26	Total Bypass and Special Rates Sales and										
27	Transportation Service										
28	Cost of Gas Sold	35,189.9		782	11,977.6		328	435.0		40	1,150
29											
30	Total Sales and Transportation										
31	Transportation Service										
32	Cost of Gas Sold	154,257.0		$729,424	51,987.4		$214,498	5,929.3		$22,958	$966,880

REVENUE UNDER PROPOSED 2006 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Terajoules	Revenue -- At Existing Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Exiisting Rates -- Average $/GJ	Revenue ($000)	Increase / (Decrease) -1.48% $/GJ	of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CAPTIVE										
2	Captive Sales										
3	Schedule 1 - Residential	73,565.4	$12.3840	$911,046	$4.1137	$302,627	($0.0608)	($4,473)	736,535	$12.3232	$906,573
4	Schedule 2 - Small Commercial	23,129.9	11.5280	266,630	3.2177	74,425	(0.0476)	(1,101)	73,476	11.4804	265,529
5	Schedule 3 - Large Commercial	15,516.2	10.6670	165,515	2.4567	38,118	(0.0363)	(563)	4,644	10.6307	164,952
6											
7	Total Schedules 1 , 2 and 3	112,211.5		1,343,191		415,170		(6,137)			1,337,054
8											
9											
10	Schedule 4 - Seasonal Service	161.3	9.4230	1,520	1.3887	224	(0.0186)	(3)	21	9.4044	1,517
11	Schedule 5 - General Firm Service	3,805.0	10.0920	38,401	2.0449	7,781	(0.0305)	(116)	352	10.0615	38,285
12											
13	Industrials										
14	Schedule 7 - Interruptible	53.4	9.7190	519	1.6667	89	(0.0248)	(1)	4	9.6942	518
15											
16	Schedule 10 - Interruptible	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
17											
18	Total Industrials	53.4		519		89		(1)			518
19											
20											
21	Schedule 6 - N G V Fuel - Stations	166.2	11.2330	1,867	3.3634	559	(0.0497)	(8)	38	11.1833	1,859
22	- VRA's	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
23											
24	Total Captive Sales	116,397.4		1,385,498		423,823		(6,266)	815,070		1,379,231
25											
26	Captive Transportation Service										
27	Schedule 22 - Firm Service	10,664.5	0.7140	7,610	0.6743	7,191	(0.0099)	(106)	18	0.7041	7,504
28	- Interruptible Service	11,811.7	0.7460	8,811	0.7355	8,687	(0.0108)	(128)	24	0.7352	8,683
29	Schedule 23 - Large Commercial	5,672.4	2.4900	14,127	2.4774	14,053	(0.0367)	(208)	1,147	2.4533	13,919
30	Schedule 25 - Firm Service	14,080.0	1.7390	24,479	1.7213	24,236	(0.0254)	(358)	619	1.7136	24,121
31	Schedule 27 - Interruptible Service	5,566.2	1.1170	6,218	1.1054	6,153	(0.0163)	(91)	97	1.1007	6,127
32											
33	Total Captive Transportation Service	47,794.8		61,245		60,320		(891)	1,905		60,354
34											
35	Captive Sales - Terasen Gas Squamish	379.0	12.1450	4,603	3.8865	1,473	(0.0554)	(21)	3,352	12.0896	4,582
36											
37	Total Captive Sales & Transportation Service	164,571.2		$1,451,346		$485,616		($7,178)	820,327		$1,444,167

REVENUE UNDER PROPOSED 2006 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

			Revenue -- At Existing Rates --		Gross Margin -- At Existing Rates --		Increase / (Decrease) -1.48% of Margin			Revenue ---- Revised Rates ----	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Revenue ($000)	$/GJ	Revenue ($000)	Average Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Bypass and Special Rates										
2											
3	Bypass and Special Rates - Sales										
4	Residential - Option A	0.0	$0.0000	$0	$0.0000	$0	$0.0000	$0	0	$0.0000	$0
5	Schedule 4 - Seasonal Service	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
6	Schedule 5 - General Firm Service	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
7	Industrials										
8	Schedule 7 - Interruptible	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
9											
10	Schedule 10 - Interruptible	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
11											
12	Total Large Industrial	0.0		0		0		0			0
13											
14	Schedule 6 - N G V Fuel - Stations	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
15	- VRA's	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
16											
17	Total Non-Captive Sales	0.0		0		0		0	0		0
18											
19	Non-Captive Transportation Service										
20	Schedule 22 - Firm Service	10,425.3	0.1950	2,031	0.1654	1,725	0.0000	0	1	0.1950	2,031
21	Schedule 22 - Interruptible	1,730.3	0.6500	1,125	0.6410	1,109	0.0000	0	9	0.6500	1,125
22	Schedule 25 - Interruptible	1,867.9	0.4440	829	0.4165	778	0.0000	0	7	0.4440	829
23	Columbia - Byron Creek	119.4	0.4220	50	0.3298	39	0.0000	0	1	0.4220	50
24	Burrard Transportation - Firm	1,073.7	9.1270	9,800	9.1040	9,775	0.0000	0	1		9,800
25	Terasen Gas (Vancouver Island)	32,385.9	0.1270	4,101	0.1037	3,360	0.0000	0	1	0.1270	4,101
26	SCP Third Party Revenues			11,072		11,072					11,072
27	Total Non-Captive Transportation Service	47,602.5		29,008		27,858		0	20		29,008
28											
29	Total Non-Captive Sales and										
30	Transportation Service	47,602.5		29,008		27,858		0	20		29,008
31											
32	TOTAL CAPTIVE AND NON-CAPTIVE SALES AND										
33	TRANSPORTATION SERVICE	212,173.7		$1,480,354		$513,474		($7,178)	$820,347		$1,473,176

TERASEN GAS INC.

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge (incl TGS)	$5,130	$5,268	$138	
4					
5	Connection Charge and NSF Cheque	4,330	4,339	$9	
6					
7	Total Other Utility Revenue	9,460	9,607	147	
8					
9	**Miscellaneous Revenue**				
10					
11	TGVI Wheeling Charge	4,087	4,101	$14	
12					
13	SCP Third Party Revenue	11,072	11,072	$0	
14					
15	Other	218	130	($88)	
16					
17	Total Miscellaneous	15,377	15,303	(74)	
18					
19	**Total Other Operating Revenue**	$24,837	$24,910	$73	- Tab A-1, Page 7

TERASEN GAS INC.

2006 ANNUAL REVIEW
2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

REVISED FORECASTS AND PROJECTIONS FOR
2007 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-5 INDEX

2007 OPERATING AND MAINTENANCE EXPENSE FOR THE YEAR ENDING DECEMBER 31, 2007

In accordance with the PBR settlement, the 2007 operating and maintenance costs are determined on a formula-based approach that starts from a base of the 2003 Decision O&M, escalated by growth in customers and inflation less an adjustment factor of 66% of CPI (BC). The forecast of 2007 inflation based on CPI (BC) is 2.0% as discussed under Section A, Tab 2.

For the purpose of 2007 rates setting, 2006 formula-based O&M expense has been adjusted based on updated 2006 customer accounts. Per Commission Order No. G-51-03, a true-up does not occur on CPI. Further, a customer count-related true-up for 2006 overhead capitalization does not occur. The detail calculation of adjusted 2006 O&M base is shown on Page 2 of this Tab.

A rate base deferral account has been established to record the difference between the O&M that TGS would have been allowed in 2007 in its cost of service, had it not amalgamated with TGI and the O&M expenses that, under the PBR, are allowed to amalgamated TGI in 2007. An amount of $106,000 after tax has been deferred in 2007 as shown in Tab 3, Page 13.1.

For 2007, the annual operating and maintenance expenses are based on the following formula:

Gross O&M = 2007 Adjusted O&M X [(1 + customer growth) X (1 + CPI – adjustment factor)] + Pension & Insurance Variance

Gross 2007 O&M	$ 199.462 million
Capitalized Overhead	(27.535) million
Fort Nelson O&M and Vehicle Lease	(2.655) million
Net 2007 O&M	$ 169.272 million

Details in support of the above calculation can be found on Page 2 of this Tab.

As per Commission Order No. G-51-03, variances between PBR formula based pension and insurance costs and forecast cost of service based have also been included as 2007 O&M expenses. Based on the calculation shown on Page 3 of this tab, an amount of $1,195,000 is included as a reduction to 2007 O&M expenses. Forecast 2006 cost of service variances are trued up and captured in deferral accounts under Section A, Tab 3, Page 13.3.

Consistent with the 2003 Decision and the terms of the Settlement, the Company has kept the overheads capitalized rate at 16% for the 2007 year.

AMALGAMATED TGI (TERASEN GAS INC. + TERASEN GAS SQUAMISH INC.)

FORMULA CALCULATION OF
OPERATING AND MAINTENANCE EXPENSE
FOR THE YEARS ENDING DECEMBER 31, 2007
($000) - Except where noted

Line No.	Description		TGI 2003 Decision Adjusted for TPIP	TGI Approved 2004	Adjusted Base 2004	TGI Approved 2005	Adjusted Base 2005	TGI Approved 2006	Adjusted Base 2006	Change	TGI+TGS Forecast 2007	TGI Forecast 2007	TGS Forecast 2007
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Average Number of Customers - Forecast		770,368	777,779		790,385		804,316		13,587	820,347	816,995	3,352
2	Percentage Growth in Average Customers									1.68%			
3													
4	Average Number of Customers - True up (Actual/Projection)				779,498		791,647		806,760 *				
5	Percentage Growth in Average Customers												
6													
7	Annual Inflation Rate - CPI									2.00%			
8	Adjustment Factor									1.32%			
9													
10	Total Gross O & M Expense before TPIP		$176,915										
11	TPIP		5,505										
12	Total Gross O & M Expense		182,420	185,740	186,089	190,575	190,888	195,394	196,001	4,656	200,657	199,837	820
13	Pension & Insurance Variance			2,144	2,144	11	11	1,525	1,525	(2,720)	(1,195)	(1,153)	(41)
14	Adjusted Total Gross O&M Expense			187,884	188,233	190,586	190,899	196,919	197,526		199,462	198,684	779
15													
16	Less: Adjustments for Overhead Capitalized Purpose												
17	Fort Nelson	($581)											
18	Vehicle Lease	(1,833)											
19	DRIA	(1,652)											
20	OPEB	(6,329)											
21	Capital-related Portion - CustomerWorks	(8,978)											
22	Total Items Not Subject to Overheads	($19,373)	(19,373)	(19,726)	(19,763)	(20,239)	(20,273)	(20,752)	(20,816)		(21,311)	(21,224)	(87)
23	Less: TPIP Not Subject to Overhead		(5,505)	(5,605)	(5,616)	(5,751)	(5,761)	(5,897)	(5,915)		(6,056)	(6,031)	(25)
24	Total O&M Subject to Capitalized Overhead		157,542	162,553	162,854	164,596	164,865	170,270	170,795	1,300	172,095	171,429	667
25													
26	Capitalized Overhead at 16%		25,207	26,009	26,009	26,335	26,335	27,243	27,243		27,535	27,429	106
27	Gross O&M Less Capitalized Overhead		157,213	161,875	162,224	164,251	164,564	169,676	170,283	1,644	171,927	171,255	672
28													
29	Less: Fort Nelson		(581)	(592)	(593)	(607)	(608)	(622)	(624)	(15)	(639)	(637)	(2)
30	Vehicle Lease		(1,833)	(1,866)	(1,870)	(1,915)	(1,918)	(1,963)	(1,969)	(47)	(2,016)	(2,008)	(8)
31	Total Utility O&M		$154,799	$159,417	$159,761	$161,729	$162,038	$167,091	$167,690	$1,582	$169,272	$168,610	$662
32													
33													

34 **Notes:**

35 * Forecasted average TGI customers 803,686 and average TGS customers 3,074 as at December 31, 2006.

AMALGAMATED TGI (TERASEN GAS INC. + TERASEN GAS SQUAMISH INC.)

FORMULA CALCULATION OF O & M EXPENSE
PENSION AND INSURANCE VARIANCE
FOR THE YEARS ENDING DECEMBER 31, 2007
($000) - Except where noted

Line No.	Particulars	Terasen Gas Inc. Decision 2003	Approved 2004	Adjusted Base 2004	Approved 2005	Adjusted Base 2005	Approved 2006	Adjusted Base 2006	Change	TGI+TGS Forecast 2007	TGI Forecast 2007	TGS Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**Formula Based**											
2	Pension	$5,543	$5,644	$5,654	$5,791	$5,800	$5,937	$5,956	$141	$6,097	$6,072	$25
3	Insurance	3,661	$3,728	$3,735	$3,825	$3,831	$3,921	$3,934	$93	$4,027	$4,011	$16
4	Total	9,204	9,372	9,389	9,615	9,631	9,859	9,889	235	10,124	10,083	41
5												
6	**Cost of Service Based**											
7	Pension		5,616		4,626		6,299			3,862	3,862	0
8	Insurance		5,900		5,000		5,085			5,067	5,067	0
9	Total		11,516		9,626		11,384			8,929	8,929	0
10												
11	**Pension & Insurance Variance**											
12	Pension		(28)		(1,165)		362			(2,235)	(2,235)	0
13	Insurance		2,172		1,175		1,164			1,040	1,040	0
14	**Total Pension and Insurance Variance**		$2,144		$11		$1,525			($1,195)	($1,195)	$0

TERASEN GAS INC.

2006 ANNUAL REVIEW
2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

REVISED FORECASTS AND PROJECTIONS FOR 2007 REVENUE REQUIREMENTS AND OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-6 INDEX

2007 TAXES AND OTHER EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2007

1. PROPERTY TAX EXPENSE

Under the PBR, property taxes will be forecast each year for the Annual Review process. The Property Tax deferral account will collect all variances from the forecast amount included in rates.

The projected 2006 property tax is expected to be lower than previous forecast by $945,900. Under the terms of the Negotiated Settlement, forecast variances are afforded deferral treatment. For 2007, the forecast property tax is $44,452,000, which includes $101,000 for Squamish. Details in support of this amount can be found on Page 4 of this tab.

Property taxes are levied under legislation against the Company by Provincial, Municipal and other local governments.

1% Tax

The 1% tax in lieu of general municipal taxes (“1% tax”) is calculated based on the amount of revenues collected for gas consumed within municipal boundaries multiplied by 1% (1.25% for the City of Vancouver). Payments of the 1% tax to municipalities are lagged relative to increases and decreases in revenues due to provisions in the applicable legislation and agreements. 2007 budget payments are based on actual 2005 revenues, except for Vancouver which will be based on 2006 revenues. It is estimated that Vancouver revenues will increase by 14.7%.

General, School and Other

Property taxes include general, school and other property taxes as well as Oil and Gas Commission fees. Assessed values for land and improvements are estimated using 2006 actual assessments and applying various market adjustments. The 2007 forecast includes:

a) An adjustment of 5% to office improvements and 0% to other improvements except for pipe.

b) An adjustment of 10% to fee-owned land for offices, and 5% for all other fee lands to cover expected increases in land prices.

c) An average increase of 10% to transmission pipeline, based on projected increases in labour, material and other costs.

d) An increase of 3% in distribution pipelines for increased costs such as Polyethylene Pipe, Steel Pipe, Fuel, and labour.

e) Net additions to distribution pipeline are estimated at $22,717,828.

It is expected that Mill rates will generally decrease as a result of rising assessment values. Mill rates used in calculating taxes payable are forecast to change as follows:

a) First Nations: 0.5%

b) General Municipal Rate: 0.5%

c) General Vancouver Rate: -0.5%

d) General Rural Rates: -1.0%

e) General University Endowment Land Rate: 1.0%

f) School Rates: -0.5%

g) Other Rates: 1.0%

Beyond the changes mentioned above and revenue-driven changes in the 1% tax, no additional property tax increases are included. As indicated in the Application section, Terasen Gas seeks continuation of the deferral account treatment for variances in property taxes from forecast.

2. LARGE CORPORATIONS TAX (LCT)

The LCT was eliminated in 2006, therefore no provision for LCT expense has been made for 2007. The LCT of 0.125% which was included in 2006 rates has been deferred in accordance with the terms of the 2004-2007 PBR.

3. INCOME TAX EXPENSE

Income tax expense is determined based on taxable earnings calculated on the basis of revenues and costs in accordance with the applicable provisions of the *Income Tax Act*, multiplied by the combined provincial and federal income tax rates. For regulatory purposes, income tax expense is calculated following the taxes payable method of accounting for income taxes. For 2006 and 2007, the corporate income tax rate is set at 33.00% .

TERASEN GAS INC.

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	B.C.U.C. Account Number	2006 Approved	2007 Total Expenses	2007 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Property Taxes (incl TGS)	305-010					
2							
3	1% in Lieu of General Municipal Tax		12,992	$14,356	$14,356	$1,364	
4							
5	General, School and Other		28,387	30,096	30,096	1,709	
6							
7			41,379	$44,452	$44,452	3,073	
8							
9	B.C. Corporation Capital Tax		0	0	0	0	
10							
11	Total		$41,379	$44,452	$44,452	$3,073	- Tab A-1, Page 7

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 ----Revised Rates----- Revised Revenue	2007 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$186,364	$188,725	($2,767)	$185,958	($406)	- Tab A-1, Page 7
3	Deduct - Interest on Debt	(109,168)	(109,712)	0	(109,712)	(544)	
4	Add- Non-Tax Ded. Expense (Net)	(1,348)	(2,290)	0	(2,290)	(942)	- Tab A-6, Page 6
5							
6	Accounting Income After Tax	75,848	76,723	(2,767)	73,956	(1,893)	
7	Add (Deduct) - Timing Differences	(6,115)	(7,553)	0	(7,553)	(1,438)	- Tab A-6, Page 6
8	Add - Large Corporation Tax	1,885	0	0	0	(1,885)	- Tab A-6, Page 9
9							
10	Taxable Income After Tax	$71,618	$69,170	($2,767)	$66,403	($5,215)	
11							
12	Income Tax Rate (Current Tax)	34.120%	33.000%	33.000%	33.000%	-1.120%	
13	1 - Current Income Tax Rate	65.880%	67.000%	67.000%	67.000%	1.120%	
14							
15	Taxable Income (L10 / L13)	$99,023	$103,238	($4,129)	$99,109	$86	
16							
17							
18	Income Tax - Current (L12 x L15)	$37,092	$34,068	($1,362)	$32,706	($4,386)	
19	- Deferred Income Tax						
20	- Large Corporation Tax	1,885	0	0	0	(1,885)	- Tab A-6, Page 9
21							
22	Total	$38,977	$34,068	($1,362)	$32,706	($6,271)	- Tab A-1, Page 7
23							
24	REVENUE DEFICIENCY						
25	Earned Return	$186,364		($2,767)	$185,958		- Tab A-1, Page 7
26	Add - Income Taxes	38,977		(1,362)	32,706		- Tab A-1, Page 7
27	Deduct - Utility Income Before Taxes,						
28	Present Rates	(205,565)		0	(222,793)		- Tab A-1, Page 7
29	Corporate Capital Tax	0		0	0		
30							
31	Deficiency After Corporate Capital Tax	$19,776		($4,129)	($4,129)		

TERASEN GAS INC.
NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007	Change	Reference
	(1)	(2)	(5)	(4)	(5)
1	ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME				
2					
3	Amortization of Deferred Charges	($1,748)	($2,725)	($977)	- Tab A-3, Page 13.1
4					
5	Non-tax Deductible Expenses	400	435	$35	
6					
7					
8					
9	Total Permanent Differences	($1,348)	($2,290)	($942)	- Tab A-1, Page 8
10					
11	TIMING DIFFERENCE ADJUSTMENTS				
12					
13	Depreciation (incl TGS)	$85,642	$87,426	$1,784	- Tab A-6, Page 7
14	Amortization of Debt Issue Expenses	1,215	1,081	($134)	
15	Debt Issue Costs	(971)	(1,421)	($450)	
16	Capital Cost Allowance (incl TGS)	(81,814)	(83,019)	($1,205)	- Tab A-6, Page 8
17	Cumulative Eligible Capital Allowance	(1,158)	(1,057)	$101	
18	Long Term Compensation	0	1,901	$1,901	
19	Unfunded Pension	1,319	(1,814)	($3,133)	
20	Overheads Capitalized Expensed for Tax Purposes	(10,216)	(10,326)	($110)	
21	Discounts on Debt Issue and Other	(132)	(321)	($189)	
22	Timing Differences - TGI	(6,115)	(7,551)	(1,436)	
23	Timing Differences - TGS (ECE)		(2)	(2)	
24					
25	Total Timing Differences	($6,115)	($7,553)	($1,438)	- Tab A-1, Page 8

TERASEN GAS INC.
DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	Depreciation Provision (incl TGS)				
2					
3	Total Depreciation Expense	$94,012	$92,184	($1,828)	- Tab A-3, Page 15.3
4					
5	Less: Amortization of Contributions in Aid of Construction	(8,370)	(4,758)	$3,612	- Tab A-3, Page 9
6		85,642	87,426	$1,784	
7					
8	Amortization Expense (incl TGS)				
9					
10	Amortization of Deferred Charges	($1,748)	($2,725)	($977)	- Tab A-3, Page 13.1
11					
12					
13		(1,748)	(2,725)	(977)	
14					
15	TOTAL	$83,894	$84,701	$807	- Tab A-1, Page 7

TERASEN GAS INC.
CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Class	CCA Rate %	12/31/2006 UCC Balance	Opening Adjustments	TGS Amalgamation	2007 Net Additions	2007 CCA
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$1,357,427	($16,218)	$5,282	$78,789	($55,435)
2	2	6%	197,644	1	7	0	(11,859)
3	3	5%	3,296	1		0	(165)
4	6	10%	281	0	1	0	(28)
5	7	15%	0	35		43	(8)
6	8	20%	20,666	57	53	4,636	(4,619)
7	9	25%	1	0		0	0
8	10	30%	8,049	(190)	57	59	(2,384)
9	12	100%	0	0		0	0
10	13		6,936	9	15	773	(1,126)
11	14		8	(0)		0	(2)
12	17	8%	287	(0)	0	0	(23)
13	29	100%	0	0		0	0
14	38	30%	35	0		0	(11)
15	39	25%	1	(0)		0	0
16	45	45%	10,256	221		8,066	(6,529)
17	49	8%	0	6,262		8,224	(830)
18		Total	$1,604,887	($9,822)	$5,414	$100,590	($83,019)

CALCULATION OF LARGE CORPORATION TAX
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Reference	2006 Approved	2007 Existing Rates	2007 Revised Rates	Change
	(1)	(2)	(3)	(4)	(5)	(6)
1	Large Corporation Tax					
2						
3	Utility Capital (Line 26)		2,524,015	$2,492,566	$2,492,583	($31,432)
4	Add: Security Deposits		2,712	2,796	2,796	84
5	Long Term Construction Advances		8	8	8	0
6	Deferred Income Tax		364	606	606	242
7	Work in Progress Attracting AFUDC		3,178	42,130	42,130	38,952
8	Sub-total		2,530,277	2,538,106	2,538,123	7,846
9						
10	Utility Portion of $50,000,000 or $0 Deduction					
11	(Line 38 x $50,000,000 or $0)		(47,835)	(47,885)	(47,885)	(50)
12						
13	Taxable Capital		$2,482,442	$2,490,221	$2,490,238	$7,796
14						
15	Large Corporation Tax Rate		0.125%	0.0000%	0.0000%	-0.1250%
16						
17	Large Corporation Tax		$3,103	$0	$0	($3,103)
18	Less: Surtax	1.12%	(1,218)	0	0	1,218
19						
20	Large Corporation Tax		$1,885	$0	$0	($1,885)
21						
22						
23	Net Plant in Service, Ending	- Tab A-1, Page 6	2,334,068	$2,371,871	$2,371,871	$37,803
24	All Other Rate Base Items	- Tab A-1, Page 6	189,947	120,695	120,712	(69,235)
25						
26	Utility Capital		2,524,015	2,492,566	2,492,583	(31,432)
27						
28	Non-Rate Base Items					
29	Net Book Value of Lower Mainland Premium		101,970	97,670	97,670	(4,300)
30	Disallowed Plant Costs		1,990	1,890	1,890	(100)
31	Plant Held for Future Use		55	55	55	0
32	Fort Nelson Division		4,203	4,303	4,303	100
33	Squamish Gas Co. Ltd.		6,050	6,200	6,050	0
34						
35	Total Capital		$2,638,283	$2,602,684	$2,602,551	($35,732)
36						
37						
38	Proportion of Utility Capital to Total Capital		95.67%	95.77%	95.77%	0.10%

TERASEN GAS INC.

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2007 RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2007

Under the terms of the 2004 – 2007 PBR Settlement the short term interest rate and new long term issues will be updated each fall for the Annual Review process. The interest deferral account will collect short term rate variances and all variances with respect to long term issues.

Long-Term Debt

Total long-term debt of $1,470.0 million is entirely TGI related.

The planned June 30, 2006 $100 million long-term debt issue was delayed by three months. On September 25, 2006, $120 million of 30-year debt with a coupon rate of 5.550% was issued.

Medium-term notes Series 13 and Series 20 totaling $250 million are set to mature in 2007. A $230 million 10-year debt issue with a forecast rate of 5.350% is planned for July 31, 2007.

Unfunded Debt

The unfunded debt rate for 2007 is set at 4.75% based on the current outlook for short-term rates in the year.

Of the total amalgamated unfunded debt of $137.9 million, $134.2 million is attributable to TGI while the remaining $3.7 million is attributable to TGS.

Common Equity

The revenue requirement information included is based on the allowed 2006 return on equity ("ROE") of 8.80% plus the effects of the anticipated amalgamation of Squamish to yield an 8.80141% ROE on an amalgamated basis. The common equity component of the amalgamated entity will move from 35% (as it is now for TGI) to a weighted average of TGI and TGS which will be 35.01238% for 2007. The 2007 rates for TGI will be adjusted from those in these Annual Review materials to take into account the Commission's determination of the allowed ROE for the low risk benchmark utility, which determination is expected sometime in late November 2006.

TERASEN GAS INC.

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$58,943	$855	$58,088	12.054%	$58,943	$7,105	
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	2005 Long Term Debt Issue - Coastal Facilities	1-Jan-2005	1-Jan-2008	6.100%	50,300	50	50,250	6.113%	50,300	3,075	
5											
6	Medium Term Note - Series 9	21-Oct-1997	2-Jun-2008	6.200%	55,000	454	54,546	6.308%	55,000	3,469	
7	Med.Term Note - Series 9 (Re-opened)	19-Nov-1998	2-Jun-2008	6.200%	58,000	681	57,319	6.036%	58,000	3,501	
8	Med.Term Note - Series 9 (Re-opening)	21-Sep-1999	2-Jun-2008	6.200%	75,000	2,053	72,947	6.578%	75,000	4,933	
9											
10	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,137	147,863	7.065%	150,000	10,597	
11	Medium Term Note - Series 13	16-Oct-2000	16-Oct-2007	6.500%	100,000	728	99,272	6.632%	78,904	5,233	
12	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,856	148,144	6.595%	150,000	9,893	
13	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970	
14	2005 Medium Term Note - Series 20	31-Oct-2005	31-Oct-2007	3.850%	150,000	474	149,526	4.515%	124,521	5,622	
15	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	1,200	118,800	5.619%	120,000	6,743	
16	2007 Medium Term Debt Issue - Series 22	31-Jul-2007	31-Jul-2017	5.350%	230,000	2,300	227,700	5.481%	97,041	5,319	
17											
18	LILO Obligations - Kelowna							5.846%	29,753	1,739	
19	LILO Obligations - Nelson							7.032%	4,704	331	
20	LILO Obligations - Vernon							7.968%	14,124	1,125	
21	LILO Obligations - Prince George							6.936%	36,028	2,499	
22	LILO Obligations - Creston							6.207%	3,405	211	
23											
24									$1,412,996	$96,817	
25	Debentures:										
26	Series E	8-Jun-1989	7-Jun-2009	10.750%	59,890	637	59,253	10.927%	59,890	6,544	
27									$59,890	$6,544	
28											
29	Sub-Total								$1,472,886	$103,361	
30	Less - Fort Nelson Division Portion of Long Term Debt								(2,835)	(199)	
31	Total								$1,470,051	$103,162	7.018%

TERASEN GAS INC.

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TERASEN GAS (SQUAMISH) INC.

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Core	2007 Non-Core	2007 Bypass and Special Rates	2007 Total	Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RATE CHANGE REQUIRED						
2							
3	Gas Sales and Transportation Revenue,						
4	At Prior Year's Rates	$0	$4,603			$4,603	$4,603
5							
6	Add - Other Revenue Related to SCP Third Party						
7	Revenue / Terasen Gas (Vancouver Island)					0	0
8							
9	Total Revenue	0	4,603	0	0	4,603	4,603
10							
11	Less - Cost of Gas	0	(3,130)			(3,130)	(3,130)
12							
13	Gross Margin	$0	$1,473	$0	$0	$1,473	$1,473
14							
15	Revenue Deficiency (Surplus)	$0	$30	$0	$0	$30	
16							
17	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	2.04%	0.00%	0.00%	2.04%	
18							
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	0.65%	0.00%	0.00%	0.65%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 Adjustments	2007 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$0	$0	$0	$0	$0	
2	CPCNs	0	8,137	0	8,137	8,137	
3							
4	Additions	0	858	0	858	858	
5	Disposals	0	(87)	0	(87)	(87)	
6							
7	Plant in Service, Ending	0	8,908	0	8,908	8,908	
8							
9	Add - Intangible Plant	0	777	0	777	777	
10							
11		0	9,685	0	9,685	9,685	
12							
13	Contributions In Aid of Construction	0	(728)	0	(728)	(728)	
14							
15	Less - Accumulated Depreciation	0	(2,102)	0	(2,102)	(2,102)	
16							
17							
18	Net Plant in Service, Ending	$0	$6,855	$0	$6,855	$6,855	
19							
20							
21	Net Plant in Service, Beginning	$0	$6,924	$0	$6,924	$6,924	
22							
23							
24	Net Plant in Service, Mid-Year (**FORMULA NPIS**)	$0	$6,889	$0	$6,889	$6,889	
25	Adjustment to 13-Month Average	0	0		0	0	
26	Construction Advances	0	0		0	0	
27	Work in Progress, No AFUDC	0	0		0	0	
28	Unamortized Deferred Charges	0	120		120	120	
29	Cash Working Capital	0	(692)	0	(692)	(692)	
30	Other Working Capital	0	50		50	50	
31	Deferred Income Tax, Mid-Year	0	(242)		(242)	(242)	
32	LILO Benefit	0			0	0	
33	Utility Rate Base	$0	$6,125	$0	$6,125	$6,125	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 ----Revised Rates----- Revised Revenue	2007 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	0	379		379	(379)	
3	Transportation	0			0	0	
4		0	379	0	379	(379)	
5							
6	Average Rate per GJ						
7	Sales	$0.000	$12.145	$0.079	$12.224	($12.224)	
8	Transportation	$0.000			$0.000	$0.000	
9	Average	$0.000	$12.145	$0.079	$12.224	($12.224)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$0	$4,603		$4,603	($4,603)	
13	- Increase / (Decrease)	0		30	30	(30)	
14							
15	Transportation - Existing Rates	0			0	0	
16	- Increase / (Decrease)	0			0	0	
17	Total	0	4,603	30	4,633	(4,633)	
18							
19	Cost of Gas Sold (Including Gas Lost)	0	3,130	0	3,130	(3,130)	
20							
21	Gross Margin	0	1,473	30	1,503	(1,503)	
22							
23	Operation and Maintenance (**FORMULA O&M**)	0	662		662	(662)	
24	Vehicle Lease	0			0	0	
25	Property and Sundry Taxes	0	101		101	(101)	
26	Depreciation and Amortization (**FORMULA DEP'N**)	0	199		199	(199)	
27	Other Operating Revenue (**FORMULA LPC**)	0	(21)		(21)	21	
28		0	941	0	941	(941)	
29	Utility Income Before Income Taxes	0	532	30	562	(562)	
30							
31	Income Taxes	0	74	10	84	(84)	- Tab A-8, Page 4
32							
33	EARNED RETURN	$0	$458	$20	$478	($478)	- Tab A-8, Page 5
34							
35	UTILITY RATE BASE	$0	$6,125	($0)	$6,125	($6,125)	- Tab A-8, Page 2
36							
37	RATE OF RETURN ON UTILITY RATE BASE	0.000%	7.47%		7.80%	-7.80%	

TERASEN GAS (SQUAMISH) INC.

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

			2007				
				----Revised Rates-----			
Line No.	Particulars	2006 Approved	Existing Rates	Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$0	$458	$20	$478	$478	- Tab A-8, Page 5
3	Deduct - Interest on Debt	0	(250)	1	(250)	(250)	
4	Add- Non-Tax Ded. Expense (Net)	0			0	0	
5							
6	Accounting Income After Tax	0	208	21	229	229	
7	Add (Deduct) - Timing Differences	0	(57)	0	(57)	(57)	
8	Add - Large Corporation Tax	0			0	0	
9							
10	Taxable Income After Tax	$0	$151	$21	$172	$172	
11							
12	Income Tax Rate (Current Tax)	34.120%	33.000%	33.000%	33.000%	-1.120%	
13	1 - Current Income Tax Rate	65.880%	67.000%	67.000%	67.000%	1.120%	
14							
15	Taxable Income (L10 / L13)	$0	$225	$30	$255	$255	
16							
17	Income Tax - Current (L12 x L15)	$0	$74	$10	$84	$84	
18							
19	- Large Corporation Tax	0			0	0	
20							
21	Total	$0	$74	$10	$84	$84	- Tab A-8, Page 3
22							
23							
24	REVENUE DEFICIENCY						
25	Earned Return	$0		$20	$478	$478	
26	Add - Income Taxes	0		10	84	84	
27	Deduct - Utility Income Before Taxes,						
28	Existing Rates	0			(532)	(532)	
29	Corporate Capital Tax	0			0	0	
30							
31	Deficiency/(Surplus) After Corporate Capital Tax	$0		$30	$30	$30	

TERASEN GAS (SQUAMISH) INC.

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2007 AT 2006 RATES							
2	Long-Term Debt			$3,336	54.46% *	7.018%	3.822%	
3	Unfunded Debt			339	5.54% **	4.750%	0.263%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			2,450	40.00%	9.120%	3.648%	
6								
7				$6,125	100.00%		7.722%	
8								
9	2007 REVISED RATES							
10	Long-Term Debt			$3,336	54.47%	7.018%	3.822%	$234
11	Unfunded Debt		$339					
12	Adjustment, Revised Rates		0	339	5.53%	4.750%	0.263%	16
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			2,450	40.00%	9.300%	3.720%	228
15								
16				$6,125	100.00%		7.804%	$478
17								
18								
19								

20 Notes:
21 * Mirrors TGI's Long Term and Short Term debt financing structure of 59% and 6%, respectively. Long Term Debt 54.46% = 60% * 59% / 65%.
22 ** Mirrors TGI's Long Term and Short Term debt financing structure of 59% and 6%, respectively. Short Term Debt 5.54% = 60% * 6% / 65%.
23

TERASEN GAS INC.

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TERASEN GAS INC.

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Core	2007 Non-Core	2007 Bypass and Special Rates	2007 Total	Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RATE CHANGE REQUIRED						
2							
3	Gas Sales and Transportation Revenue,						
4	At Prior Year's Rates	$1,626,467	$1,384,979	$61,764	$13,835	$1,460,578	($165,889)
5							
6	Add - Other Revenue Related to SCP Third Party						
7	Revenue / Terasen Gas (Vancouver Island)	15,159	0	0	15,173	15,173	14
8							
9	Total Revenue	1,641,626	1,384,979	61,764	29,008	1,475,751	(165,875)
10							
11	Less - Cost of Gas	(1,151,571)	(961,245)	(1,355)	(1,150)	(963,750)	187,821
12							
13	Gross Margin	$490,055	$423,734	$60,409	$27,858	$512,001	$21,946
14							
15	Revenue Deficiency (Surplus)	$19,776	($3,563)	($508)	$0	($4,071)	
16							
17	Revenue Deficiency (Surplus) as a % of Gross Margin	4.04%	-0.84%	-0.84%	0.00%	-0.80%	
18							
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.20%	-0.26%	-0.82%	0.00%	-0.28%	

TERASEN GAS INC.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 Adjustments	2007 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$3,067,485	$3,140,710	$0	$3,140,710	$73,225	- Tab A-9, Page 7.1
2	CPCNs	4,564	0	0	0	(4,564)	- Tab A-9, Page 7.1
3							
4	Additions	125,924	128,859	0	128,859	2,935	- Tab A-9, Page 7.1
5	Disposals	(56,345)	(32,831)	0	(32,831)	23,514	- Tab A-9, Page 7.1
6							
7	Plant in Service, Ending	3,141,628	3,236,738	0	3,236,738	95,110	
8							
9	Add - Intangible Plant	837	837	0	837	0	
10							
11		3,142,465	3,237,575	0	3,237,575	95,110	
12							
13	Contributions In Aid of Construction	(137,019)	(130,434)	0	(130,434)	6,585	- Tab A-9, Page 8
14							
15	Less - Accumulated Depreciation	(671,378)	(742,125)	0	(742,125)	(70,747)	- Tab A-9, Page 12
16							
17							
18	Net Plant in Service, Ending	$2,334,068	$2,365,016	$0	$2,365,016	$30,948	
19							
20							
21	Net Plant in Service, Beginning	$2,302,480	$2,332,763	$0	$2,332,763	$30,283	- Tab A-9, Page 9
22							
23							
24	Net Plant in Service, Mid-Year	$2,318,274	$2,348,890	$0	$2,348,890	$30,616	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(11)	(11)	0	(11)	0	
27	Work in Progress, No AFUDC	11,902	10,771	0	10,771	(1,131)	
28	Unamortized Deferred Charges	13,109	(8,347)	0	(8,347)	(21,456)	- Tab A-9, Page 10.1
29	Cash Working Capital	(29,050)	(24,522)	17	(24,505)	4,545	- Tab A-9, Page 11
30	Other Working Capital	194,361	143,932	0	143,932	(50,429)	- Tab A-9, Page 11
31	Deferred Income Tax, Mid-Year	(364)	(364)	0	(364)	0	
32	LILO Benefit	(2,312)	(2,243)	0	(2,243)	69	
33	Utility Rate Base	$2,505,909	$2,468,106	$17	$2,468,123	($37,786)	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 ----Revised Rates----- Revised Revenue	2007 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	116,140	116,397	0	116,397	257	- Tab A-9, Page 13
3	Transportation	98,287	95,397	0	95,397	(2,890)	- Tab A-9, Page 13
4		214,427	211,794	0	211,794	(2,633)	
5							
6	Average Rate per GJ						
7	Sales	$13.539	$11.903	$0.000	$11.873	($1.666)	
8	Transportation	$0.751	$0.787	$0.000	$0.782	$0.031	
9	Average	$7.677	$6.896	$0.000	$6.877	($0.800)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,555,107	$1,385,498	$0	$1,385,498	($169,609)	- Tab A-9, Page 14
13	- Increase	17,318	0	(3,565)	(3,565)	(20,883)	
14							
15	Transportation - Existing Rates	71,360	75,080	0	75,080	3,720	- Tab A-9, Page 14
16	- Increase	2,458		(506)	(506)	(2,964)	
17	**Total**	1,646,243	1,460,578	(4,071)	1,456,507	(189,736)	
18							
19	Cost of Gas Sold (Including Gas Lost)	1,151,571	963,750	0	963,750	(187,821)	- Tab A-9, Page 15.1
20							
21	**Gross Margin**	494,672	496,828	(4,071)	492,757	(1,915)	
22							
23	Operation and Maintenance	167,091	168,610	0	168,610	1,519	
24	Vehicle Lease	1,804	1,993	0	1,993	189	
25	Property and Sundry Taxes	41,379	44,351	0	44,351	2,972	- Tab A-9, Page 18
26	Depreciation and Amortization	83,894	84,502	0	84,502	608	- Tab A-9, Page 21
27	Other Operating Revenue	(24,837)	(24,889)	0	(24,889)	(52)	- Tab A-9, Page 17
28		269,331	274,567	0	274,567	5,236	
29	Utility Income Before Income Taxes	225,341	222,261	(4,071)	218,190	(7,151)	
30							
31	Income Taxes	38,977	33,978	(1,344)	32,634	(6,343)	- Tab A-9, Page 4
32							
33	**EARNED RETURN**	$186,364	$188,283	($2,727)	$185,556	($808)	- Tab A-9, Page 5
34							
35	**UTILITY RATE BASE**	$2,505,909	$2,468,106	$17	$2,468,123	($37,786)	- Tab A-9, Page 2
36							
37	**RATE OF RETURN ON UTILITY RATE BASE**	7.437%	7.630%		7.518%	0.08%	

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 ----Revised Rates----- Revised Revenue	2007 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$186,364	$188,283	($2,727)	$185,556	($808)	- Tab A-9, Page 5
3	Deduct - Interest on Debt	(109,168)	(109,537)	(1)	(109,538)	(370)	
4	Add- Non-Tax Ded. Expense (Net)	(1,348)	(2,290)	0	(2,290)	(942)	- Tab A-9, Page 20
5							
6	Accounting Income After Tax	75,848	76,456	(2,728)	73,728	(2,120)	
7	Add (Deduct) - Timing Differences	(6,115)	(7,471)	0	(7,471)	(1,356)	- Tab A-9, Page 20
8	Add - Large Corporation Tax	1,885	0	0	0	(1,885)	- Tab A-9, Page 23
9							
10	Taxable Income After Tax	$71,618	$68,985	($2,728)	$66,257	($5,361)	
11							
12	Income Tax Rate (Current Tax)	34.120%	33.000%	33.000%	33.000%	-1.120%	
13	1 - Current Income Tax Rate	65.880%	67.000%	67.000%	67.000%	1.120%	
14							
15	Taxable Income (L10 / L13)	$108,710	$102,963	($4,072)	$98,891	($9,819)	
16							
17	Income Tax - Current (L12 x L15)	$37,092	$33,978	($1,344)	$32,634	($4,458)	
18							
19	- Large Corporation Tax	1,885	0	0	0	(1,885)	
20							
21	Total	$38,977	$33,978	($1,344)	$32,634	($6,343)	- Tab A-9, Page 3
22							
23							
24	REVENUE DEFICIENCY						
25	Earned Return	$186,364		($2,727)	$185,556	($808)	
26	Add - Income Taxes	38,977		(1,344)	32,634	(6,343)	
27	Deduct - Utility Income Before Taxes,						
28	Existing Rates	(205,565)		0	(222,261)	(16,696)	
29	Corporate Capital Tax	0		0	0	0	
30							
31	Deficiency After Corporate Capital Tax	$19,776		($4,071)	($4,071)	($23,847)	

TERASEN GAS INC.

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2007 AT 2006 RATES							
2	Long-Term Debt	- Tab A-9, Page 23		$1,470,051	59.56%	7.018%	4.180%	
3	Unfunded Debt			134,218	5.44%	4.750%	0.258%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			863,837	35.00%	9.120%	3.192%	
6								
7				$2,468,106	100.00%		7.630%	
8								
9	2007 REVISED RATES							
10	Long-Term Debt	- Tab A-9, Page 23		$1,470,051	59.56%	7.018%	4.180%	103,162
11	Unfunded Debt		$134,218					
12	Adjustment, Revised Rates		11	134,229	5.44%	4.750%	0.258%	6,376
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			863,843	35.00%	8.800%	3.080%	76,018
15								
16				$2,468,123	100.00%		7.518%	$185,556
17								
18	2006 APPROVED RATES							
19	Long-Term Debt			$1,432,919	57.18%	7.072%	4.044%	$101,331
20	Unfunded Debt		$195,980					
21	Adjustment, Revised Rates		(58)	195,922	7.82%	4.000%	0.313%	7,837
22	Preference Shares			0	0.00%	0.000%	0.000%	0
23	Common Equity			877,068	35.00%	8.800%	3.080%	77,182
24								
25				$2,505,909	100.00%		7.437%	$186,350
26								
27	CHANGE FROM 2006 APPROVED							
28	Long-Term Debt			$37,132	2.38%	-0.054%	0.136%	$1,831
29	Unfunded Debt		($61,762)					
30	Adjustment, Revised Rates		69	(61,693)	-2.38%	0.750%	-0.055%	(1,461)
31	Preference Shares			0	0.00%	0.000%	0.000%	0
32	Common Equity			(13,225)	0.00%	0.000%	0.000%	(1,164)
33								
34				($37,786)	0.00%		0.081%	($794)

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 Adjustments	2007 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$3,067,485	$3,140,710	$0	$3,140,710	$73,225	- Tab A-9, Page 7.1
2	CPCNs	4,564	0	0	0	(4,564)	- Tab A-9, Page 7.1
3							
4	Additions	125,924	128,859	0	128,859	2,935	- Tab A-9, Page 7.1
5	Disposals	(56,345)	(32,831)	0	(32,831)	23,514	- Tab A-9, Page 7.1
6							
7	Plant in Service, Ending	3,141,628	3,236,738	0	3,236,738	95,110	
8							
9	Add - Intangible Plant	837	837	0	837	0	
10							
11		3,142,465	3,237,575	0	3,237,575	95,110	
12							
13	Contributions In Aid of Construction	(137,019)	(130,434)	0	(130,434)	6,585	- Tab A-9, Page 8
14							
15	Less - Accumulated Depreciation	(671,378)	(742,125)	0	(742,125)	(70,747)	- Tab A-9, Page 12
16							
17							
18	Net Plant in Service, Ending	$2,334,068	$2,365,016	$0	$2,365,016	$30,948	
19							
20							
21	Net Plant in Service, Beginning	$2,302,480	$2,332,763	$0	$2,332,763	$30,283	- Tab A-9, Page 9
22							
23							
24	Net Plant in Service, Mid-Year	$2,318,274	$2,348,890	$0	$2,348,890	$30,616	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(11)	(11)	0	(11)	0	
27	Work in Progress, No AFUDC	11,902	10,771	0	10,771	(1,131)	
28	Unamortized Deferred Charges	13,109	(8,347)	0	(8,347)	(21,456)	- Tab A-9, Page 10.1
29	Cash Working Capital	(29,050)	(24,522)	17	(24,505)	4,545	- Tab A-9, Page 11
30	Other Working Capital	194,361	143,932	0	143,932	(50,429)	- Tab A-9, Page 11
31	Deferred Income Tax, Mid-Year	(364)	(364)	0	(364)	0	
32	LILO Benefit	(2,312)	(2,243)	0	(2,243)	69	
33	Utility Rate Base	$2,505,909	$2,468,106	$17	$2,468,123	($37,786)	

GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	Balance 12/31/2005	CPCN'S	2006 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2006	CPCN'S	2007 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	401 Franchise Consents	$99	$0	$0	$0	$0	$99	$0	$0	$0	$0	$99
2	402 Other Intangible Plant	835	0	0	0	0	835	0	0	0	0	835
3	TOTAL INTANGIBLE PLANT	934	0	0	0	0	934	0	0	0	0	934
4												
5	430 Manufact'd Gas - Land	31	0	0	0	0	31	0	0	0	0	31
6	432 Manufact'd Gas - Struct. & Improvements	438	0	0	0	0	438	0	0	0	0	438
7	433 Manufacturing Equipment	139	0	0	0	0	139	0	0	0	0	139
8	434 Gas Holders - Manufacturing	358	0	0	0	0	358	0	0	0	0	358
9	436 Compressed Equipment	53	0	0	0	0	53	0	0	0	0	53
10	437 Measuring and Regulating Equipment	309	0	0	0	0	309	0	0	0	0	309
11	440/441 Land in Fee Simple and Land Rights	927	0	0	0	0	927	0	0	0	0	927
12	442 Structures and Improvements	5,455	0	0	0	0	5,455	0	0	0	0	5,455
13	443 Gas Holders - Storage	17,358	0	600	0	0	17,958	0	610	0	0	18,568
14	446 Compressor Equipment	0	0	0	0	0	0	0	0	0	0	0
15	447 Measuring and Regulating Equipment	0	0	0	0	0	0	0	0	0	0	0
16	448 Purification Equipment	0	0	0	0	0	0	0	0	0	0	0
17	449 Local Storage Equipment	16,734	0	0	0	0	16,734	0	0	0	0	16,734
18	TOTAL MANUFACTURED GAS / LOCAL STORAGE	41,802	0	600	0	0	42,402	0	610	0	0	43,012
19												
20	460 Land in Fee Simple	7,444	0	0	0	0	7,444	0	0	0	0	7,444
21	461 Land Rights	40,804	3	1,324	0	0	42,131	0	1,355	0	0	43,486
22	462 Compressor Structures	15,183	0	410	0	0	15,593	0	417	0	0	16,010
23	463 Measuring Structures	4,363	0	0	0	0	4,363	0	0	0	0	4,363
24	464 Other Structures and Improvements	4,881	0	0	0	0	4,881	0	0	0	0	4,881
25	465 Mains	700,807	4,176	3,271	(164)	0	708,090	0	3,328	(166)	0	711,252
26	466 Compressor Equipment	103,928	0	49	0	0	103,977	0	50	0	0	104,027
27	467 Measuring and Regulating Equipment	44,291	0	5,440	0	0	49,731	0	5,536	0	0	55,267
28	468 Communication Structures and Equipment	1,701	0	698	0	0	2,399	0	710	0	0	3,109
29	469 Other Transmission Equipment	0	0	0	0	0	0	0	0	0	0	0
30	TOTAL TRANSMISSION PLANT	923,402	4,179	11,192	(164)	0	938,609	0	11,396	(166)	0	949,839
31												
32	470 Land	3,249	0	0	0	0	3,249	0	0	0	0	3,249
33	471 Land Rights	679	0	0	0	0	679	0	0	0	0	679
34	472 Structures and Improvements	7,397	0	376	0	0	7,773	0	382	0	0	8,155
35	473 Services	560,956	0	24,466	(3,670)	0	581,752	0	25,227	(3,784)	0	603,195
36	474 House Regulators and Meter Installations	148,700	0	9,653	(483)	0	157,870	0	9,856	(493)	0	167,233
37	475 Mains	763,945	0	33,395	(3,339)	0	794,001	0	34,171	(3,417)	0	824,755
38	476 Compressor Equipment											0
39												0
40	-All Other	575	0	0	0	0	575	0	0	0	0	575
41	477 Measuring and Regulating Equipment	77,165	0	10,272	(514)	0	86,923	0	10,454	(523)	0	96,854
42	478 Meters	203,520	0	15,932	(797)	0	218,655	0	16,269	(813)	0	234,111
43	479 Other Distribution Equipment	0	0	0	0	0	0	0	0	0	0	0
44	TOTAL DISTRIBUTION PLANT	1,766,186	0	94,094	(8,803)	0	1,851,477	0	96,359	(9,030)	0	1,938,806

TERASEN GAS INC.

GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	Balance 12/31/2005	CPCN'S	2006 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2006	CPCN'S	2007 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	480 Land	$20,962	$0	21	0	$0	$20,983	$0	$22	$0	$0	$21,005
2	481 Land Rights	0	0	0	0	0	0	0	0	0	0	0
3	482 Structures and Improvements											
4												
5	-All Other	83,879	0	648	(180)	0	84,347	0	663	0	0	85,010
6	483 Office Furniture and Equipment											
7	-Furniture & Equipment	23,803	0	488	(48)	0	24,243	0	499	(78)	0	24,664
8	-Computers - Hardware	28,951	0	6,705	(5,917)	0	29,739	0	6,862	(7,999)	0	28,602
9	-Computer Software - Non-Infrastructure	34,648	0	2,489	(13,803)	0	23,334	0	2,547	(7,208)	0	18,673
10	-Computer Software - Infrastructure/Custom	94,809	157	6,299	(27,351)	0	73,914	0	6,445	(7,636)	0	72,723
11												
12												
13	484 Transportation Equipment	623	0	49	(7)	0	665	0	51	0	0	716
14												
15	485 Heavy Work Equipment	366	0	0	(83)	0	283	0	0	0	0	283
16	486 Tools and Work Equipment	29,239	0	2,228	(167)	0	31,300	0	2,280	(167)	0	33,413
17	487 Equipment on Customer's Premises	1,813	0	0	0	0	1,813	0	0	0	0	1,813
18	488 Communication Equipment	15,593	0	1,099	(178)	0	16,514	0	1,125	(547)	0	17,092
19	489 Other General Equipment											0
20	-Stores Material, Capital	0	0	0	0	0	0	0	0	0	0	0
21	-All Other	0	0	0	0	0	0	0	0	0	0	0
22												
23	TOTAL GENERAL EQUIPMENT	334,686	157	20,026	(47,734)	0	307,135	0	20,494	(23,635)	0	303,994
24												
25	492 Gas Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
26	496 Unclassified Plant	0	0	0	0	0	0	0	0	0	0	0
27	497 Allowance for Funds Used											0
28	During Construction	0	0	0	0	0	0	0	0	0	0	0
29	498 Overhead Charged To Construction	0	0	0	0	0	0	0	0	0	0	0
30	499 Plant Suspense	153	0	0	0	0	153	0	0	0	0	153
31												
32	TOTAL UNCLASSIFIED PLANT	153	0	0	0	0	153	0	0	0	0	153
33												
34	TOTAL CAPITAL	$3,067,163	$4,336	$125,912	($56,701)	$0	$3,140,710	$0	$128,859	($32,831)	$0	$3,236,738

TERASEN GAS INC.

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars		Balance 12/31/2005	2006 Additions	2006 Retirements	Balance 12/31/2006	2007 Additions	2007 Retirements	Balance 12/31/2007
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	DSEP/GEAP	211-06	$12,671	$0	$0	$12,671	$0	$0	$12,671
2									
3	NGV Conversion Grants	211-07	0	0	0	0	0	0	0
4									
5	NGV Station Grants	211-08	0	0	0	0	0	0	0
6									
7	Furniture & Equipment	211-10	111	0	0	111	0	0	111
8									
9	Software Tax Savings - Non-Infrastructure	211-11	7,613	1,068	(624)	8,057	964	(22)	8,999
10	- Infrastructure/Custom	211-11	37,125	2,703	(16,685)	23,143	2,441	(15,842)	9,742
11	Service Installation Fee	211-12	19,378	2,736	0	22,114	2,826	0	24,940
12									
13	Other	211-00 to 05	67,769	3,054	0	70,823	3,148	0	73,971
14									
15	TOTAL		144,667	9,561	(17,309)	136,919	9,379	(15,864)	130,434
16									
17									
18									
19	Amortization	211-15 to 22							
20									
21	- Software Tax Savings - Non-Infrastructure		(4,836)	(1,523)	624	(5,735)	(1,611)	22	(7,324)
22	- Infrastructure/Custom		(18,111)	(4,641)	16,685	(6,067)	(807)	15,842	8,968
23	- Other		(21,782)	(2,198)	0	(23,980)	(2,326)	0	(26,306)
24									
25									
26	Total Amortization		(44,729)	(8,362)	17,309	(35,782)	(4,744)	15,864	(24,662)
27									
28	NET		$99,938	$1,199	$0	$101,137	$4,635	$0	$105,772

TERASEN GAS INC.

NET GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2006 TO 2007
($000)

Line No.	Particulars	Projection 2006	Forecast 2007	Reference
	(1)	(2)	(3)	(4)
1	Gas Plant in Service - December 31, Previous Year	$3,067,163	$3,140,710	- Tab A-9, Page 7.1
2				
3	Add: CPCNs on January 1, Beginning of the Year	4,336	0	- Tab A-9, Page 7.1
4				
5	Adjusted Opening Gas Plant in Service	3,071,499	3,140,710	
6				
7	Intangible Plant	837	837	- Tab A-9, Page 2
8				
9	Less: Contribution in Aid of Construction	(144,667)	(136,919)	- Tab A-9, Page 8
10				
11	Less: Accumulated Depreciation and Amortization	(625,613)	(671,865)	- Tab A-9, Page 12
12				
13				
14				
15	Net Gas Plant in Service as at January 1, Beg of Year	$2,302,056	$2,332,763	- Tab A-9, Page 2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Account	Balance 12/31/2006	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2007	Mid-Year Average 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($120)	$0	$0	$0	$69	$0	($51)	($85)
2	Deferred Interest - funding benefit via Customer Deposits		($153)	$0	0	$0	$72	$0	($81)	($117)
3										
4	NGV Conversion Grants	#17977	152	70	(23)	47	(56)	0	143	148
5										
6	2003 Revenue Requirement	#17989	78	0	0	0	(49)	0	29	53
7	2004-2007 Revenue Requirements	#17952	50	0	0	0	(25)	0	25	38
8	Future Revenue Requirements	#18160	67	350	(116)	234	0	0	301	184
9										
10	Demand Side Management	#17916	1,358	1,500	(495)	1,005	(667)	0	1,695	1,527
11	DSM DRIA	#17961	0	0	0	0	0	0	0	0
12										
13	Property Tax Deferral	#17915	(493)	0	0	0	197	0	(297)	(395)
14										
15	M.C.R.A.	#17926	18,948	45,315	(14,954)	30,361	0	(49,309)	(0)	9,474
16	C.C.R.A.	#18137	(54,674)	121,800	(40,194)	81,606	0	(26,932)	(0)	(27,337)
17	C.C.R.A./M.C.R.A Interest	#17973	(2,009)	0	0	0	0	2,009	0	(1,004)
18										
19	RSAM	#17927	33,965	0	0	0	0	(11,322)	22,643	28,304
20	RSAM Interest	#17999	616	(15)	5	(10)	0	(205)	400	508
21										
22	Revelstoke Propane Cost	#27902	93	139	(46)	93	0	(186)	(0)	46
23										
28	- Extraordinary Plant Loss - Lochburn	#17998	93	0	0	0	0	0	93	93
31										
32	2005 BC Tax Rate Reduction Deferral	#17940	(21)	0	0	0	21	0	0	(11)
33										
34	Vehicle Lease Deferral	#17941	716	-	0	0	(358)	0	358	537
35										
36										

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Account	Balance 12/31/2006	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2007	Mid-Year Average 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ROE Hearing Costs - 2005	#17985	$449	$0	$0	$0	($150)	$0	$299	$374
2										
3	Earnings Sharing Mechanism	#17982	(8,535)	0	0	0	0	8,535	0	(4,267)
4										
5	NGV Compression Equip. Recovery	#17992	746	0	0	0	(249)	0	497	621
6										
7	Overheads Change - Income Tax Refund	#17995	(140)	0	0	0	140	0	0	(70)
8	CIAOC Software Tax Savings/OH Change	#17995	(807)	0	0	0	807	0	0	(404)
9	Bad Debt Allowance for Rates 14 & 14A	#17949	57	33	(11)	22	0	0	78	68
10	Other Post Employment Benefits	#17991/93/25154	(20,219)	(5,821)	1,921	(3,900)	0	0	(24,119)	(22,169)
11										
12	Deferred 2000 SCP Cost of Service	#17997	62	0	0	0	(62)	0	0	31
13										
14	SCP Net Mitigation Revenues	#17912	(2,757)	(955)	315	(640)	1,028	0	(2,369)	(2,563)
15	SCP West to East Transmission	#17913	189	0	0	0	(300)	0	(112)	39
16	SCP PG&E Contract Cancellation	#17936	1,988	0	0	0	(663)	0	1,325	1,656
17	SCP Provincial Sales Tax Reassessment		10,000	0	0	0	0	0	10,000	10,000
18										
19	CCT Deferral	#17924	(133)	0	0	0	133	0	0	(66)
20	CCT Assessment	#17929	161	0	0	0	(116)	0	45	103
21										
22	Pension Variance	#17946	(1,597)	0	0	0	1,597	0	0	(798)
23	Insurance Variance	#17947	(195)	0	0	0	195	0	(0)	(98)
24										
25	BCUC Levies	#18149	(240)	0	0	0	240	0	0	(120)
26	OSC Certification Compliance	#18148	(123)	352	(116)	236	(113)	0	0	(61)
27										
28	2006 LCT Elimination	#18502	(3,103)	0	0	0	1,034	0	(2,069)	(2,586)
29										
30	Total Deferred Charges for Rate Base		($25,534)	$162,767	($53,714)	$109,053	$2,725	($77,410)	$8,834	($8,347)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Particulars	Account	Balance 12/31/2005	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2006	Mid-Year Average 2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($1,901)	$187	($62)	$125	$1,656	$0	($120)	($1,011)
2	Deferred Interest - funding benefit via Customer Deposits		($192)	($36)	$12	($24)	$63	$0	($153)	($172)
3										
4	NGV Conversion Grants	#17977	151	85	(28)	57	(56)	0	152	152
5										
6	2003 Revenue Requirement	#17989	142	0	0	0	(64)	0	78	110
7	2004-2007 Revenue Requirements	#17952	73	0	0	0	(23)	0	50	61
8	Future Revenue Requirements	#18160	0	100	(33)	67	0	0	67	34
9										
10	Demand Side Management	#17916	1,006	1,500	(495)	1,005	(654)	0	1,358	1,182
11	DSM DRIA	#17961	(145)	0	0	0	145	0	0	(73)
12										
13	Property Tax Deferral	#17915	(196)	(946)	312	(634)	336	0	(493)	(345)
14										
15	M.C.R.A.	#17926	(26,629)	40,716	(13,436)	27,280	0	18,297	18,948	(3,840)
16	C.C.R.A.	#18137	915	(82,968)	27,379	(55,589)	0	0	(54,674)	(26,880)
17	C.C.R.A./M.C.R.A Interest	#17973	(1,369)	(1,715)	566	(1,149)	0	509	(2,009)	(1,689)
18										
19	RSAM	#17927	38,784	11,450	(3,778)	7,672	0	(12,491)	33,965	36,374
20	RSAM Interest	#17999	358	478	(158)	320	0	(63)	616	487
21										
22	Revelstoke Propane Cost	#27902	208	(173)	57	(116)	0	0	93	151
23										
28	- Extraordinary Plant Loss - Lochburn	#17998	119	0	0	0	(27)	0	93	106
31										
32	2005 BC Tax Rate Reduction Deferral	#17940	(750)	0	0	0	729	0	(21)	(386)
33										
34	Vehicle Lease Deferral	#17941	1,033	-	0	0	(316)	-	716	875
35										
36	Note: Lines 14, 15, and 18 are MCRA, CCRA, and RSAM actual activities and balances.									

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Particulars	Account	Balance 12/31/2005	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2006	Mid-Year Average 2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ROE Hearing Costs - 2005	#17985	$227	$330	($109)	$221	$0	$0	$449	$338
2										
3	Earnings Sharing Mechanism	#17982	(4,860)	(12,738)	4,203	(8,535)	0	4,860	(8,535)	(6,697)
4										
5	NGV Compression Equip. Recovery	#17992	994	0	0	0	(249)	0	746	870
6										
7	Overheads Change - Income Tax Refund	#17995	(278)	0	0	0	138	0	(140)	(209)
8	CIAOC Software Tax Savings/OH Change	#17995	(1,615)	0	0	0	808	0	(807)	(1,211)
9	Bad Debt Allowance for Rates 14 & 14A	#17949	36	32	(11)	21	0	0	57	46
10	Other Post Employment Benefits	#17991/93/25154	(16,444)	(5,634)	1,859	(3,775)	0	0	(20,219)	(18,332)
11										
12	Deferred 2000 SCP Cost of Service	#17997	126	0	0	0	(64)	0	62	94
13										
14	SCP Net Mitigation Revenues	#17912	(776)	(3,679)	1,214	(2,465)	484	0	(2,757)	(1,767)
15	SCP West to East Transmission	#17913	495	0	0	0	(306)	0	189	342
16	SCP PG&E Contract Cancellation	#17936	2,650	0	0	0	(662)	0	1,988	2,319
17	SCP Provincial Sales Tax Reassessment		0	10,000	0	10,000	0	0	10,000	5,000
18										
19	CCT Deferral	#17924	(265)	0	0	0	133	0	(133)	(199)
20	CCT Assessment	#17929	247	247	(82)	165	(251)	0	161	204
21										
22	Pension Variance	#17946	232	(2,766)	913	(1,853)	24	0	(1,597)	(682)
23	Insurance Variance	#17947	(284)	(259)	85	(174)	263	0	(195)	(240)
24										
25	BCUC Levies	#18149	117	(371)	122	(249)	(108)	0	(240)	(61)
26	OSC Certification Compliance	#18148	4	182	(60)	122	(250)	0	(123)	(59)
27										
28	2006 LCT Elimination	#18502	0	(3,103)	0	(3,103)	0	0	(3,103)	(1,552)
29										
30	Total Deferred Charges for Rate Base		($7,786)	($49,079)	$18,470	($30,610)	$1,750	$11,112	($25,534)	($16,660)

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Existing Rates	2007 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	($21,047)	($16,420)	($16,403)	$4,644	
4						
5	Minimum Cash Balances/					
6	Customer Deposits	(2,712)	(2,796)	(2,796)	(84)	
7						
8	Less - Funds Available:					
9						
10	Reserve for Bad Debts	(3,070)	(2,890)	(2,890)	180	
11						
12	Withholdings From					
13	Employees	(2,221)	(2,416)	(2,416)	(195)	
14						
15	Subtotal	(29,050)	(24,522)	(24,505)	4,545	- Tab A-9, Page 2
16						
17	**Other Working Capital Items**					
18	Inventories	6,371	6,296	6,296	(75)	
19	Transmission Line Pack Gas	5,055	3,199	3,199	(1,856)	
20	Gas in Storage	182,935	134,437	134,437	(48,498)	
21						
22						
23	Subtotal	194,361	143,932	143,932	(50,429)	- Tab A-9, Page 2
24						
25	Total	$165,311	$119,410	$119,427	($45,884)	

ACCUMULATED DEPRECIATION
FOR THE YEARS ENDING DECEMBER 31, 2006 - 2007
($000)

Line No.	Particulars	Projection 2006	Forecast 2007	Reference
	(1)	(2)	(3)	(4)
1	Balance, Beginning	$670,342	$707,647	- Tab A-9, Pages 12.3 and 12.6
2				
3	CIAOC Amortization Balance, Beginning	(44,729)	(35,782)	- Tab A-9, Page 8
4				
5	Gas Plant Held for Future Use			
6	Balance, Beginning	-	-	
7				
8	Retirement Work in Progress	-	-	
9				
10	Utility Accumulated Depreciation			
11	Balance, Beginning	625,613	671,865	- Tab A-9, Page 9
12				
13	Depreciation Provision			
14	Total Plant	94,006	91,971	- Tab A-9, Pages 12.3 and 12.6
15	Less - Gas Plant Held for Future Use	0	0	
16	Less Prior Year Adjustments			
17	Less - Amortization of Contributions in			
18	Aid of Construction	(8,362)	(4,744)	- Tab A-9, Page 8
19				
20		85,644	87,227	
21				
22	Plant Retirements	(56,701)	(32,831)	- Tab A-9, Page 12.3
23				
24	CIAOC Retirements	17,309	15,864	- Tab A-9, Page 8
25				
26	Removal Costs	-	-	
27				
28	Proceeds on Disposals	-	-	
29				
30		(39,392)	(16,967)	
31				
32	Balance, Ending	$671,865	$742,125	- Tab A-9, Page 2

TERASEN GAS INC.

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Account	Balance 12/31/2006	Annual Depreciation Rate %	Provision 2007 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2006	Accumulated 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	48	49
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	347	354
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	47	48
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	28	29
7	402-00 Other Intangible Plant - Lease	772	Lease	1	0	0	0	0	115	116
8		1,771		11	0	0	0	0	585	596
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	430 Manufact'd Gas - Land	31	0.00%	0	0	0	0	0	0	0
22	432 Manufact'd Gas - Struct. & Improvements									
23	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
24	- Masonry Buildings	438	1.50%	7	0	0	0	0	84	91
25	433 Manufacturing Equipment	139	3.00%	4	0	0	0	0	37	41
26	434 Gas Holders - Manufacturing	358	2.00%	7	0	0	0	0	151	158
27	436 Compressor Equipment	53	3.00%	2	0	0	0	0	20	22
28	437 Measuring & Regulating	309	3.00%	9	0	0	0	0	123	132
29	440/441 Land in Fee Simple and Land Rights	927	0.00%	0	0	0	0	0	1	1
30	442-00 Structures and Improvements	5,455	4.00%	218	0	0	0	0	1,870	2,088
31	443-00 Gas Holders Storage	17,958	4.00%	718	0	0	0	0	7,868	8,586
32	449-00 Local Storage Equipment	16,734	4.00%	669	0	0	0	0	7,757	8,426
33		42,402		1,634	0	0	0	0	17,911	19,545

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Account	Balance 12/31/2006	Annual Depreciation Rate %	Provision 2007 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2006	Accumulated 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461 Land Rights - Byron Creek	$16	5.00%	$1	$0	$0	$0	$0	$17	$18
3	460-00 / 461-00 Land / Land Rights	49,559	0.00%	0	0	0	0	0	(1,035)	(1,035)
4	462-00 Structures and Improvements - Compressor Stn	15,593	3.00%	468	0	0	0	0	3,989	4,457
5	463-00 Measuring & Regulating	4,363	3.00%	131	0	0	0	0	1,036	1,167
6	464-00 Other Structures - Frame Buildings	4,881	3.00%	146	0	0	0	0	804	950
7	465-00 Mains & Crossings	707,388	2.00%	14,148	0	(166)	0	0	149,890	163,872
8	465-00 Mains & Crossings - Byron Creek	702	5.00%	35	0	0	0	0	723	758
9	466-00 Compressor Equipment	103,977	3.00%	3,119	0	0	0	0	25,632	28,751
10	467-00 Measuring & Regulating	43,736	3.00%	1,312	0	0	0	0	6,614	7,926
11	467-10 Telemetering	5,995	10.00%	600	0	0	0	0	5,823	6,423
12	468-00 Communications Structures & Equip.	2,399	10.00%	240	0	0	0	0	383	623
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		938,609		20,200	0	(166)	0	0	193,876	213,910
15										
16	**DISTRIBUTION PLANT**									
17	470 Land	3,249	0.00%	0	0	0	0	0	35	35
18	471 Land Rights	678	0.00%	0	0	0	0	0	0	0
19	471 Land Rights - Byron Creek	1	5.00%	0	0	0	0	0	3	3
20	472-00 Structures & Improvements									
21	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
22	-Frame Buildings	7,771	3.00%	233	0	0	0	0	1,998	2,231
23	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
24	-Byron Creek	2	5.00%	0	0	0	0	0	2	2
25	473-00 Services	581,752	2.00%	11,635	0	(3,784)	0	0	94,515	102,366
26	474-00 House Regulator & Meter Installation	157,870	3.57%	5,636	0	(493)	0	0	32,547	37,690
27	475-00 Mains	794,001	2.00%	15,880	0	(3,417)	0	0	195,472	207,935
28	476-00 Compressed Natural Gas									
29										
30	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
31	-All Other	575	6.67%	38	0	0	0	0	288	326
32	477-00 Measuring & Regulating	81,444	3.00%	2,443	0	(523)	0	0	9,699	11,619
33	477-10 Telemetering	5,316	10.00%	532	0	0	0	0	4,855	5,387
34	477-00 Measuring & Regulating - Byron Creek	163	5.00%	8	0	0	0	0	(51)	(43)
35	478 Meters	218,655	3.57%	7,806	0	(813)	0	0	46,045	53,038
36	479 Other Distribution Equipment	0	4.00%	0	0	0	0	0	0	0
37		1,851,477		44,211	0	(9,030)	0	0	385,408	420,589

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Account	Balance 12/31/2006	Annual Depreciation Rate %	Provision 2007 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2006	Accumulated 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	470 Land	$20,983	$0	$0	$0	$0	$0	$0	17	17
3	482-00 Structures & Improvements									
4	-Leasehold Alterations	4,086	Term - Lease	540	0	0	0	0	13,931	14,471
5	-Masonry Buildings	75,190	1.50%	1,128	0	0	0	0	(7,877)	(6,749)
6	-Frame Buildings	5,071	3.00%	152	0	0	0	0	(3,086)	(2,934)
7	483-00 Office Furniture & Equipment									
8	-Furniture & Equipment	24,243	5.00%	1,212	0	(78)	0	0	10,893	12,027
9	-Computers - Hardware	29,739	20.00%	5,948	0	(7,999)	0	0	19,894	17,843
10										
11	-Computer Software - Non-Infrastructure	23,334	20.00%	4,667	0	(7,208)	0	0	20,696	18,155
12	-Computer Software - Infrastructure/Custom	73,914	12.50%	9,239	0	(7,636)	0	0	32,567	34,170
13										
14	484-00 Transportation Equipment	665	15.00%	100	0	0	0	0	2,716	2,816
15	485-00 Maintenance & Repair Equipment	283	5.00%	14	0	0	0	0	(374)	(360)
16	486-00 Tools & Work Equipment	31,300	5.00%	1,565	0	(167)	0	0	12,323	13,721
17	487-00 Equipment on Customers' Premises	1,230	5.00%	62	0	0	0	0	799	861
18	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
19	487-XX - VRA Compressor Installation Cost	583	33.33%	194	0	0	0	0	886	1,080
20	488-00 Communication - Structures & Equip.	11,142	5.00%	557	0	(547)	0	0	2,380	2,390
21	488-00 Communication - Radios	5,372	10.00%	537	0	0	0	0	4,102	4,639
22	489-00 Other General Equipment	0	5.00%	0	0	0	0	0	0	0
23		307,135		25,915	0	(23,635)	0	0	109,867	112,147
24										
25	**UNCLASSIFIED PLANT**									
26	498-00 O&M Expense Charged to Construction	153	0.00%	0	0	0	0	0	0	0
27										
28	TOTAL	$3,141,547		$91,971	$0	($32,831)	$0	$0	$707,647	$766,787

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Account	Balance 12/31/2005	Annual Depreciation Rate %	Provision 2006 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2005	Accumulated 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	47	48
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	340	347
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	46	47
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	27	28
7	402-00 Other Intangible Plant - Lease	772	Lease	0	0	0	0	0	115	115
8		1,771		10	0	0	0	0	575	585
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	430 Manufact'd Gas - Land	31	0.00%	0	0	0	0	0	0	0
22	432 Manufact'd Gas - Struct. & Improvements									
23	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
24	- Masonry Buildings	438	1.50%	7	0	0	0	0	77	84
25	433 Manufacturing Equipment	139	3.00%	4	0	0	0	0	33	37
26	434 Gas Holders - Manufacturing	358	2.00%	7	0	0	0	0	144	151
27	436 Compressor Equipment	53	3.00%	2	0	0	0	0	18	20
28	437 Measuring & Regulating	309	3.00%	9	0	0	0	0	114	123
29	440/441 Land in Fee Simple and Land Rights	927	0.00%	0	0	0	0	0	1	1
30	442-00 Structures and Improvements	5,455	4.00%	218	0	0	0	0	1,652	1,870
31	443-00 Gas Holders Storage	17,358	4.00%	694	0	0	0	0	7,174	7,868
32	449-00 Local Storage Equipment	16,734	4.00%	669	0	0	0	0	7,088	7,757
33		41,802		1,610	0	0	0	0	16,301	17,911

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Account	Balance 12/31/2005	Annual Depreciation Rate %	Provision 2006 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2005	Accumulated 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461 Land Rights - Byron Creek	$16	5.00%	$1	$0	$0	$0	$0	$16	$17
3	460-00 / 461-00 Land / Land Rights	48,235	0.00%	0	0	0	0	0	(1,035)	(1,035)
4	462-00 Structures and Improvements - Compressor	15,183	3.00%	455	0	0	0	0	3,534	3,989
5	463-00 Measuring & Regulating	4,363	3.00%	131	0	0	0	0	905	1,036
6	464-00 Other Structures - Frame Buildings	4,881	3.00%	146	0	0	0	0	658	804
7	465-00 Mains & Crossings	704,281	2.00%	14,086	0	(164)	0	0	135,968	149,890
8	465-00 Mains & Crossings - Byron Creek	702	5.00%	35	0	0	0	0	688	723
9	466-00 Compressor Equipment	103,928	3.00%	3,118	0	0	0	0	22,514	25,632
10	467-00 Measuring & Regulating	38,296	3.00%	1,149	0	0	0	0	5,465	6,614
11	467-10 Telemetering	5,995	10.00%	600	0	0	0	0	5,223	5,823
12	468-00 Communications Structures & Equip.	1,701	10.00%	170	0	0	0	0	213	383
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		927,581		19,891	0	(164)	0	0	174,149	193,876
15										
16	**DISTRIBUTION PLANT**									
17	470 Land	3,249	0.00%	0	0	0	0	0	35	35
18	471 Land Rights	678	0.00%	0	0	0	0	0	0	0
19	471 Land Rights - Byron Creek	1	5.00%	0	0	0	0	0	3	3
20	472-00 Structures & Improvements									
21	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
22	-Frame Buildings	7,395	3.00%	222	0	0	0	0	1,776	1,998
23	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
24	-Byron Creek	2	5.00%	0	0	0	0	0	2	2
25	473-00 Services	560,956	2.00%	11,219	0	(3,670)	0	0	86,966	94,515
26	474-00 House Regulator & Meter Installation	148,700	3.57%	5,309	0	(483)	0	0	27,721	32,547
27	475-00 Mains	763,945	2.00%	15,279	0	(3,339)	0	0	183,532	195,472
28	476-00 Compressed Natural Gas									
29										
30	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
31	-All Other	575	6.67%	38	0	0	0	0	250	288
32	477-00 Measuring & Regulating	71,686	3.00%	2,151	0	(514)	0	0	8,062	9,699
33	477-10 Telemetering	5,316	10.00%	532	0	0	0	0	4,323	4,855
34	477-00 Measuring & Regulating - Byron Creek	163	5.00%	8	0	0	0	0	(59)	(51)
35	478 Meters	203,520	3.57%	7,266	0	(797)	0	0	39,576	46,045
36	479 Other Distribution Equipment	0	4.00%	0	0	0	0	0	0	0
37		1,766,186		42,024	0	(8,803)	0	0	352,187	385,408

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Account	Balance 12/31/2005	Annual Depreciation Rate %	Provision 2006 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2005	Accumulated 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	480 Land	$20,962	$0	$0	$0	$0	$0	$0	$17	$17
3	482-00 Structures & Improvements									
4	-Leasehold Alterations	4,086	Term - Lease	540	0	0	0	0	13,391	13,931
5	-Masonry Buildings	74,722	1.50%	1,121	0	(180)	0	0	(8,818)	(7,877)
6	-Frame Buildings	5,071	3.00%	152	0	0	0	0	(3,238)	(3,086)
7	483-00 Office Furniture & Equipment									
8	-Furniture & Equipment	23,803	5.00%	1,190	0	(48)	0	0	9,751	10,893
9	-Computers - Hardware	28,951	20.00%	5,790	0	(5,917)	0	0	20,021	19,894
10										
11	-Computer Software - Non-Infrastructure	34,648	20.00%	6,930	0	(13,803)	0	0	27,569	20,696
12	-Computer Software - Infrastructure/Custom	94,966	12.50%	11,871	0	(27,351)	0	0	48,047	32,567
13										
14	484-00 Transportation Equipment	623	15.00%	93	0	(7)	0	0	2,630	2,716
15	485-00 Maintenance & Repair Equipment	366	5.00%	18	0	(83)	0	0	(309)	(374)
16	486-00 Tools & Work Equipment	29,239	5.00%	1,462	0	(167)	0	0	11,028	12,323
17	487-00 Equipment on Customers' Premises	1,230	5.00%	62	0	0	0	0	737	799
18	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
19	487-XX - VRA Compressor Installation Cost	583	33.33%	194	0	0	0	0	692	886
20	488-00 Communication - Structures & Equip.	10,221	5.00%	511	0	(178)	0	0	2,047	2,380
21	488-00 Communication - Radios	5,372	10.00%	537	0	0	0	0	3,565	4,102
22	489-00 Other General Equipment	0	5.00%	0	0	0	0	0	0	0
23		334,843		30,471	0	(47,734)	0	0	127,130	109,867
24										
25	**UNCLASSIFIED PLANT**									
26	499 Plant Suspense	153	0.00%	0	0	0	0	0	0	0
27										
28	TOTAL	$3,072,336		$94,006	$0	($56,701)	$0	$0	$670,342	$707,647

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2007
(TJ)

Line No.	Particulars	2006 Approved	2007 Terajoules Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(6)
1	SALES						
2	Schedule 1 - Residential	72,934.4	73,565.4	0.0	73,565.4	631.0	
3	Schedule 2 - Small Commercial	22,333.4	23,129.9	0.0	23,129.9	796.5	
4	Schedule 3 - Large Commercial	16,273.6	15,516.2	0.0	15,516.2	(757.4)	
5							
6	Total Schedules 1, 2 and 3	111,541.4	112,211.5	0.0	112,211.5	670.1	
7							
8	Schedule 4 - Seasonal Service	120.6	161.3	0.0	161.3	40.7	
9	Schedule 5 - General Firm Service	4,205.8	3,805.0	0.0	3,805.0	(400.8)	
10							
11	Industrials						
12	Schedule 7 - Interruptible	53.9	53.4	0.0	53.4	(0.5)	
13							
14	Schedule 10	0.0	0.0	0.0	0.0	0.0	
15							
16	Total Industrials	53.9	53.4	0.0	53.4	(0.5)	
17							
18	Schedule 6 - N G V Fuel - Stations	217.8	166.2	0.0	166.2	(51.6)	
19							
20	Total Sales	116,139.5	116,397.4	0.0	116,397.4	257.9	- Tab A-9, Page 3
21							
22	TRANSPORTATION SERVICE						
23	Schedule 22 - Firm Service	23,550.8	10,664.5	11,499.0	22,163.5	(1,387.4)	
24	- Interruptible Service	15,100.5	11,811.7	1,730.3	13,542.0	(1,558.4)	
25	Schedule 23 - Large Commercial	5,185.7	5,672.4	0.0	5,672.4	486.7	
26	Schedule 25 - Firm Service	15,546.4	14,080.0	1,867.9	15,947.9	401.5	
27	Schedule 27 - Interruptible	6,103.0	5,566.2	0.0	5,566.2	(536.8)	
28	Terasen Gas (Vancouver Island)	32,685.0	0.0	32,385.9	32,385.9	(299.1)	
29	Columbia Service Area - Byron Creek	115.9	0.0	119.4	119.4	3.5	
30							
31	Total Transportation Service	98,287.3	47,794.8	47,602.5	95,397.3	(2,890.0)	- Tab A-9, Page 3
32							
33	TOTAL SALES AND TRANSPORTATION SERVICE	214,426.8	164,192.2	47,602.5	211,794.7	(2,632.1)	- Tab A-9, Page 3

TERASEN GAS INC.

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007 Gas Sales Revenue At 2006 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	SALES						
2	Residential / Residential	$1,012,064	$911,046	$0	$911,046	(101,018)	
3	Schedule 2 - Small Commercial	293,147	266,630	0	266,630	(26,517)	
4	Schedule 3 - Large Commercial	197,097	165,515	0	165,515	(31,582)	
5							
6	Total Schedules 1, 2 and 3	1,502,308	1,343,191	0	1,343,191	(159,117)	
7							
8	Schedule 4 - Seasonal Service	1,324	1,520	0	1,520	196	
9	Schedule 5 - General Firm Service	48,195	38,401	0	38,401	(9,794)	
10		49,519	39,921	0	39,921	(9,598)	
11	Industrials						
12	Schedule 7 - Interruptible	596	519	0	519	(77)	
13							
14	Schedule 10	0	0	0	0	0	
15							
16							
17	Total Industrials	596	519	0	519	(77)	
18							
19	Schedule 6 - N G V Fuel - Stations	2,684	1,867	0	1,867	(817)	
20							
21	Total Sales	1,555,107	1,385,498	0	1,385,498	(169,609)	- Tab A-9, Page 3
22							
23	TRANSPORTATION SERVICE						
24	Schedule 22 - Firm Service	18,445	7,610	11,831	19,441	996	
25	- Interruptible Service	11,228	8,811	1,125	9,936	(1,292)	
26	Schedule 23 - Large Commercial	12,391	14,127	0	14,127	1,736	
27	Schedule 25 - Firm Service	22,886	24,479	829	25,308	2,422	
28	Schedule 27 - Interruptible Service	6,362	6,218	0	6,218	(144)	
29	Terasen Gas (Vancouver Island)	0	0	0	0	0	
30	Columbia Service Area - Byron Creek	48	0	50	50	2	
31							
32	Total Transportation Service	71,360	61,245	13,835	75,080	3,720	- Tab A-9, Page 3
33							
34	TOTAL SALES AND TRANSPORTATION SERVICE	$1,626,467	$1,446,743	$13,835	$1,460,578	($165,889)	

TERASEN GAS INC. - SUMMARY BY SERVICE AREA
COST OF GAS BY RATE SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2007

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CORE AND NON-CORE										
2	Core and Non-Core Sales										
3	Schedule 1 - Residential	54,876.7	$8.2750	$454,102	16,950.3	$8.2524	$139,881	1,738.4	$8.3040	$14,436	$608,419
4	Schedule 2 - Small Commercial	16,710.1	8.3030	138,744	5,719.6	8.3273	47,629	700.2	8.3290	5,832	192,205
5	Schedule 3 - Large Commercial	12,827.4	8.1860	105,005	2,455.6	8.3377	20,474	233.2	8.2230	1,918	127,397
6	Schedules 1, 2 and 3	84,414		697,851	25,125.5		207,984	2,671.8		22,186	928,021
7											
8	Schedule 4 - Seasonal	80	8.0520	644	81.3	8.0170	652.0	0.0	0.0000	0	1,296
9	Schedule 5 - General Firm	3,141.9	8.0520	25,299	604.0	8.0170	4,842	59.1	8.1020	479	30,620
10											
11	Industrial										
12	Interruptible - Schedule 7	37.6	8.0520	303	15.8	8.0170	127	0.0	0.0000	0	430
13	- Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
14	Total Industrials	38		303	15.8		127	0.0		0	430
15											
16	N G V Fuel - Stations - Schedule 6	144	7.8740	1,134	22.2	7.8570	174	0.0	0.0000	0	1,308
17		0									
18	Total NGV	144		1,134	22.2		174	0.0		0	1,308
19											
20	Total Core and Non-Core Sales	87,818		725,231	25,848.8		213,779	2,730.9		22,665	961,675
21											
22	Core and Non-Core Transportation Service										
23	Schedule 22 - Firm Service	1,022	0.0091	9	7,383.8	0.0274	203	2,258.7	0.0916	207	419
24											
25	- Interruptible Service	10,979	0.0091	100	813.5	0.0274	23	19.0	0.0916	2	125
26		0									
27	Schedule 23 - Large Commercial	4,641	0.0091	42	983.8	0.0274	27	47.6	0.0924	4	73
28	Schedule 25 - Firm Service	9,412	0.0091	86	4,229.5	0.0275	117	438.1	0.0915	40	243
29	Schedule 27 - Interruptible Service	4,816	0.0091	44	750.4	0.0280	21	0.0	0.0000	0	65
30	Total Core and Non-Core T-Service	30,870		281	14,161.0		391	2,763.4		253	925
31											
32											
33	Total Core and Non-Core Sales and										
34	Transportation Service										
35	Cost of Gas Sold	118,688.1		$725,512	40,009.8		$214,170	5,494.3		$22,918	$962,600

TERASEN GAS INC. - SUMMARY BY SERVICE AREA
COST OF GAS BY RATE SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2007

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	BYPASS AND SPECIAL RATES										
2	Bypass and Special Rates Sales										
3	Schedule 4 - Seasonal	0.0	$0.0000	$0	0.0	$0.0000	$0	0.0	$0.0000	$0	$0
4											
5	Large Industrial										
6	Interruptible - Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
7											
8											
9	Total Large Industrial	0.0		0.0	0.0		0.0	0.0		0.0	0
10	Total Bypass and Spec. Rates Sales	0.0		0.0	0.0		0.0	0.0		0.0	0
11											
12	Bypass and Special Rates Transportation Service										
13	Schedule 22 - Firm Service	0.0	0.0091	0	10,109.7	0.0274	277	315.6	0.0916	29	306
14											
15	- Interruptible Service	1,730.3	0.0091	16	0.0	0.0274	0	0.0	0.0916	0	16
16											
17	- Burrard Thermal - Firm	1,073.7	0.0229	25	0.0		0	0.0		0	25
18	Schedule 23 - Large Commercial	0.0	0.0091	0	0.0	0.0274	0	0.0	0.0916	0	0
19	Schedule 25 - Firm Service	0.0	0.0091	0	1,867.9	0.0274	51	0.0	0.0916	0	51
20	Schedule 27 - Interruptible Service	0.0	0.0091	0	0.0	0.0274	0	0.0	0.0916	0	0
21	Byron Creek	0.0	0.0000	0	0.0	0.0000	0	119.4	0.0916	11	11
22	Centra BC (PCEC)	32,385.9	0.0229	741							741
23	Total Bypass and Spec. Rates T-Svc	35,189.9		782	11,977.6		328	435.0		40	1,150
24											
25											
26	Total Bypass and Special Rates Sales and										
27	Transportation Service										
28	Cost of Gas Sold	35,189.9		782	11,977.6		328	435.0		40	1,150
29											
30	Total Sales and Transportation										
31	Transportation Service										
32	Cost of Gas Sold	153,878.0		$726,294	51,987.4		$214,498	5,929.3		$22,958	$963,750

REVENUE UNDER PROPOSED 2006 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Terajoules	Revenue -- At Existing Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing Rates -- Average $/GJ	Revenue ($000)	Increase / (Decrease) -0.84% $/GJ	of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CAPTIVE										
2	Captive Sales										
3	Schedule 1 - Residential	73,565.4	$12.3840	$911,046	$4.1137	$302,627	($0.0346)	($2,546)	736,535	$12.3494	$908,500
4	Schedule 2 - Small Commercial	23,129.9	11.5280	266,630	3.2177	74,425	(0.0271)	(626)	73,476	11.5009	266,004
5	Schedule 3 - Large Commercial	15,516.2	10.6670	165,515	2.4567	38,118	(0.0206)	(320)	4,644	10.6464	165,195
6											
7	Total Schedules 1 , 2 and 3	112,211.5		1,343,191		415,170		(3,492)			1,339,699
8											
9											
10	Schedule 4 - Seasonal Service	161.3	9.4230	1,520	1.3887	224	(0.0124)	(2)	21	9.4106	1,518
11	Schedule 5 - General Firm Service	3,805.0	10.0920	38,401	2.0449	7,781	(0.0173)	(66)	352	10.0747	38,335
12											
13	Industrials										
14	Schedule 7 - Interruptible	53.4	9.7190	519	1.6667	89	(0.0141)	(1)	4	9.7049	518
15											
16	Schedule 10 - Interruptible	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
17											
18	Total Industrials	53.4		519		89		(1)			518
19											
20											
21	Schedule 6 - N G V Fuel - Stations	166.2	11.2330	1,867	3.3634	559	(0.0283)	(5)	38	11.2047	1,862
22	- VRA's	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
23											
24	Total Captive Sales	116,397.4		1,385,498		423,823		(3,565)	815,070		1,381,933
25											
26	Captive Transportation Service										
27	Schedule 22 - Firm Service	10,664.5	0.7140	7,610	0.6743	7,191	(0.0056)	(60)	18	0.7084	7,550
28	- Interruptible Service	11,811.7	0.7460	8,811	0.7355	8,687	(0.0062)	(73)	24	0.7398	8,738
29	Schedule 23 - Large Commercial	5,672.4	2.4900	14,127	2.4774	14,053	(0.0208)	(118)	1,147	2.4692	14,009
30	Schedule 25 - Firm Service	14,080.0	1.7390	24,479	1.7213	24,236	(0.0144)	(203)	619	1.7246	24,276
31	Schedule 27 - Interruptible Service	5,566.2	1.1170	6,218	1.1054	6,153	(0.0093)	(52)	97	1.1077	6,166
32											
33	Total Captive Transportation Service	47,794.8		61,245		60,320		(506)	1,905		60,739
34											
35	Total Captive Sales and										
36	Transportation Service	164,192.2		$1,446,743		$484,143		($4,071)	816,975		$1,442,672

TERASEN GAS INC.

REVENUE UNDER PROPOSED 2006 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Terajoules	Revenue -- At Existing Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing Rates -- Average $/GJ	Revenue ($000)	Increase / (Decrease) -0.84% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Bypass and Special Rates										
2											
3	Bypass and Special Rates - Sales										
4	Residential - Option A	0.0	$0.0000	$0	$0.0000	$0	$0.0000	$0	0	$0.0000	$0
5	Schedule 4 - Seasonal Service	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
6	Schedule 5 - General Firm Service	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
7	Industrials										
8	Schedule 7 - Interruptible	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
9											
10	Schedule 10 - Interruptible	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
11											
12	Total Large Industrial	0.0		0		0		0			0
13											
14	Schedule 6 - N G V Fuel - Stations	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
15	- VRA's	0.0	0.0000	0	0.0000	0	0.0000	0	0	0.0000	0
16											
17	Total Non-Captive Sales	0.0		0		0		0	0		0
18											
19	Non-Captive Transportation Service										
20	Schedule 22 - Firm Service	10,425.3	0.1950	2,031	0.1654	1,725	0.0000	0	1	0.1950	2,031
21	Schedule 22 - Interruptible	1,730.3	0.6500	1,125	0.6410	1,109	0.0000	0	9	0.6500	1,125
22	Schedule 25 - Interruptible	1,867.9	0.4440	829	0.4165	778	0.0000	0	7	0.4440	829
23	Columbia - Byron Creek	119.4	0.4220	50	0.3298	39	0.0000	0	1	0.4220	50
24	Burrard Transportation - Firm	1,073.7	9.1270	9,800	9.1040	9,775	0.0000	0	1		9,800
25	Terasen Gas (Vancouver Island)	32,385.9	0.1270	4,101	0.1037	3,360	0.0000	0	1	0.1270	4,101
26	SCP Third Party Revenues			11,072		11,072					11,072
27	Total Non-Captive Transportation Service	47,602.5		29,008		27,858		0	20		29,008
28											
29	Total Non-Captive Sales and										
30	Transportation Service	47,602.5		29,008		27,858		0	20		29,008
31											
32	TOTAL CAPTIVE AND NON-CAPTIVE SALES AND										
33	TRANSPORTATION SERVICE	211,794.7		$1,475,751		$512,001		($4,071)	816,995		$1,471,680

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$5,130	$5,247	$117	
4					
5	Connection Charge and NSF Cheque	4,330	4,339	$9	
6					
7	Total Other Utility Revenue	9,460	9,586	126	
6	Other Income	(319)	0		
8					
9	**Miscellaneous Revenue**				
10					
11	TGVI Wheeling Charge	4,087	4,101	$14	
12					
13	SCP Third Party Revenue	11,072	11,072	$0	
14					
15	Other	218	130	($88)	
16					
17	Total Miscellaneous	15,377	15,303	(74)	
18					
19	**Total Other Operating Revenue**	$24,837	$24,889	$52	- Tab A-9, Page 3

TERASEN GAS INC.

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	B.C.U.C. Account Number	2006 Approved	2007 Total Expenses	2007 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Property Taxes	305-010					
2							
3	1% in Lieu of General Municipal Tax		12,992	$14,319	$14,319	$1,327	
4							
5	General, School and Other		28,387	30,032	30,032	1,645	
6							
7			41,379	$44,351	$44,351	2,972	
8							
9	B.C. Corporation Capital Tax		0	0	0	0	
10							
11	Total		$41,379	$44,351	$44,351	$2,972	- Tab A-9, Page 3

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Particulars	2006 Approved	2007 Existing Rates	2007 ----Revised Rates----- Revised Revenue	2007 ----Revised Rates----- Total	Change	Reference
(1)	(2)	(3)	(4)	(5)	(6)	(7)
CALCULATION OF INCOME TAXES						
Earned Return	$186,364	$188,283	($2,727)	$185,556	(808)	- Tab A-9, Page 3
Deduct - Interest on Debt	(109,168)	(109,537)	(1)	(109,538)	(370)	
Add- Non-Tax Ded. Expense (Net)	(1,348)	(2,290)	0	(2,290)	(942)	- Tab A-9, Page 20
Accounting Income After Tax	75,848	76,456	(2,728)	73,728	(2,120)	
Add (Deduct) - Timing Differences	(6,115)	(7,471)	0	(7,471)	(1,356)	- Tab A-9, Page 20
Add - Large Corporation Tax	1,885	0	0	0	(1,885)	- Tab A-9, Page 23
Taxable Income After Tax	$71,618	$68,985	($2,728)	$66,257	(5,361)	
Income Tax Rate (Current Tax)	34.120%	33.000%	33.000%	33.000%	(0)	
1 - Current Income Tax Rate	65.880%	67.000%	67.000%	67.000%	0	
Taxable Income (L10 / L13)	$99,023	$102,963	($4,072)	$98,891	(132)	
Income Tax - Current (L12 x L15)	$37,092	$33,978	($1,344)	$32,634	(4,458)	
- Deferred Income Tax						
- Large Corporation Tax	1,885	0	0	0	(1,885)	
Total	$38,977	$33,978	($1,344)	$32,634	(6,343)	- Tab A-9, Page 3
REVENUE DEFICIENCY						
Earned Return	$186,364		($2,727)	$185,556		- Tab A-9, Page 3
Add - Income Taxes	38,977		(1,344)	32,634		- Tab A-9, Page 3
Deduct - Utility Income Before Taxes, Present Rates	(205,565)		0	(222,261)		- Tab A-9, Page 3
Corporate Capital Tax	0		0	0		
Deficiency After Corporate Capital Tax	$19,776		($4,071)	($4,071)		

($000)

Line No.	Particulars	2006 Approved	2007	Change	Reference
	(1)	(2)	(5)	(4)	(5)
1	ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME				
2					
3	Amortization of Deferred Charges	($1,748)	($2,725)	($977)	- Tab A-9, Page 10.1
4					
5	Non-tax Deductible Expenses	400	435	$35	
6					
7					
8					
9	Total Permanent Differences	($1,348)	($2,290)	($942)	- Tab A-9, Page 4
10					
11	TIMING DIFFERENCE ADJUSTMENTS				
12					
13	Depreciation	$85,642	$87,227	$1,585	- Tab A-9, Page 21
14	Amortization of Debt Issue Expenses	1,215	1,081	($134)	
15	Debt Issue Costs	(971)	(1,421)	($450)	
16	Capital Cost Allowance	(81,814)	(82,780)	($966)	- Tab A-9, Page 22
17	Cumulative Eligible Capital Allowance	(1,158)	(1,057)	$101	
18	Long term compensation	0	1,901	$1,901	
19	Unfunded Pension	1,319	(1,814)	($3,133)	
20	Overheads Capitalized Expensed for Tax Purposes	(10,216)	(10,286)	($70)	
21	Discounts on Debt Issue and Other	(132)	(321)	(189)	
22					
23	Total Timing Differences	($6,115)	($7,471)	($1,356)	- Tab A-9, Page 4

TERASEN GAS INC.
DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	2006 Approved	2007	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	Depreciation Provision				
2					
3	Total Depreciation Expense	$94,012	$91,971	($2,041)	- Tab A-9, Page 12.3
4					
5	Less: Amortization of Contributions in Aid of Construction	(8,370)	(4,744)	$3,626	- Tab A-9, Page 8
6		85,642	87,227	$1,585	
7					
8	Amortization Expense				
9					
10	Amortization of Deferred Charges	($1,748)	($2,725)	($977)	- Tab A-9, Page 10.1
11					
12					
13		(1,748)	(2,725)	(977)	
14					
15	TOTAL	$83,894	$84,502	$608	- Tab A-9, Page 3

TERASEN GAS INC.
CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Class	CCA Rate %	12/31/2006 UCC Balance	Opening Adjustments	2007 Net Additions	2007 CCA	12/312007 UCC Balance
	(1)	(2)	(3	(4)	(5)	(6)	(7)
1	1	4%	$1,357,427	($16,218)	$78,789	($55,224)	$1,364,774
2	2	6%	197,644	1	0	(11,859)	185,786
3	3	5%	3,296	1	0	(165)	3,132
4	6	10%	281	0	0	(28)	253
5	7	15%	0	35	43	(8)	70
6	8	20%	20,666	57	4,636	(4,608)	20,751
7	9	25%	1	0	0	0	1
8	10	30%	8,049	(190)	59	(2,367)	5,551
9	12	100%	0	0	0	0	0
10	13		6,936	9	773	(1,126)	6,591
11	14		8	(0)	0	(2)	6
12	17	8%	287	(0)	0	(23)	264
13	29	100%	0	0	0	0	0
14	38	30%	35	0	0	(11)	24
15	39	25%	1	(0)	0	0	1
16	45	45%	10,256	221	8,066	(6,529)	12,014
17	49	8%	0	6,262	8,224	(830)	13,656
18		Total	$1,604,887	($9,822)	$100,590	($82,780)	$1,612,874

CALCULATION OF LARGE CORPORATION TAX
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Reference	2006 Approved	2007 Existing Rates	2007 Revised Rates	Change
	(1)	(2)	(3)	(4)	(5)	(6)
1	Large Corporation Tax					
2						
3	Utility Capital (Line 26)		2,524,015	$2,486,475	$2,486,492	(37,523)
4	Add: Security Deposits		2,712	2,796	2,796	84
5	Long Term Construction Advances		8	8	8	0
6	Deferred Income Tax		364	364	364	0
7	Work in Progress Attracting AFUDC		3,178	42,130	42,130	38,952
8	Sub-total		2,530,277	2,531,773	2,531,790	1,513
9						
10	Utility Portion of $50,000,000 or $0 Deduction					
11	(Line 38 x $50,000,000 or $0)		(47,835)	(47,880)	(47,880)	(45)
12						
13	Taxable Capital		$2,482,442	$2,483,893	$2,483,910	1,468
14						
15	Large Corporation Tax Rate		0.125%	0.0000%	0.0000%	(0)
16						
17	Large Corporation Tax		$3,103	$0	$0	(3,103)
18	Less: Surtax	1.12%	(1,218)	(1,153)	(1,108)	110
19						
20	Large Corporation Tax		$1,885	$0	$0	(2,993)
21						
22						
23	Net Plant in Service, Ending	- Tab A-9, Page 2	2,334,068	$2,365,016	$2,365,016	30,948
24	All Other Rate Base Items - Lines 26 - 31 of	- Tab A-9, Page 2	189,947	121,459	121,476	(68,471)
25						
26	Utility Capital		2,524,015	2,486,475	2,486,492	(37,523)
27						
28	Non-Rate Base Items					
29	Net Book Value of Lower Mainland Premium		101,970	97,670	97,670	(4,300)
30	Disallowed Plant Costs		1,990	1,890	1,890	(100)
31	Plant Held for Future Use		55	55	55	0
32	Fort Nelson Division		4,203	4,303	4,303	100
33	Squamish Gas Co. Ltd.		6,050	6,200	6,050	0
34						
35	Total Capital		$2,638,283	$2,596,593	$2,596,460	(41,823)
36						
37						
38	Proportion of Utility Capital to Total Capital		95.67%	95.76%	95.76%	0.09%

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	33,210	42,277	11.800%	$58,943	$855	$58,088	12.054%	$58,943	$7,105	
2	Series B Purchase Money Mortgage	33,572	42,704	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	2005 Long Term Debt Issue - Coastal Facilities	38,353	39,448	6.100%	50,300	50	50,250	6.113%	50,300	3,075	
5											
6	Medium Term Note - Series 9	35,724	39,601	6.200%	55,000	454	54,546	6.308%	55,000	3,469	
7	Med.Term Note - Series 9 (Re-opened)	36,118	39,601	6.200%	58,000	681	57,319	6.036%	58,000	3,501	
8	Med.Term Note - Series 9 (Re-opening)	36,424	39,601	6.200%	75,000	2,053	72,947	6.578%	75,000	4,933	
9											
10	Medium Term Note - Series 11	36,424	47,382	6.950%	150,000	2,137	147,863	7.065%	150,000	10,597	
11	Medium Term Note - Series 13	36,815	39,371	6.500%	100,000	728	99,272	6.632%	78,904	5,233	
12	2004 Long Term Debt Issue - Series 18	38,106	49,065	6.500%	150,000	1,856	148,144	6.595%	150,000	9,893	
13	2005 Long Term Debt Issue - Series 19	38,408	49,365	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970	
14	2005 Medium Term Note - Series 20	38,656	39,386	3.850%	150,000	474	149,526	4.515%	124,521	5,622	
15	2006 Medium Term Debt Issue - Series 21	38,985	49,943	5.550%	120,000	1,200	118,800	5.619%	120,000	6,743	
16	2007 Medium Term Debt Issue - Series 22	39,294	42,947	5.350%	230,000	2,300	227,700	5.481%	97,041	5,319	
17											
18	LILO Obligations - Kelowna							5.846%	29,753	1,739	
19	LILO Obligations - Nelson							7.032%	4,704	331	
20	LILO Obligations - Vernon							7.968%	14,124	1,125	
21	LILO Obligations - Prince George							6.936%	36,028	2,499	
22	LILO Obligations - Creston							6.207%	3,405	211	
23											
24									$1,412,996	$96,817	
25	Debentures:										
28											
29	Sub-Total								$1,472,886	$103,361	
30	Less - Fort Nelson Division Portion of Long Term Debt								(2,835)	(199)	
31	Total								$1,470,051	$103,162	7.018%

TERASEN GAS INC.

2006 ANNUAL REVIEW
2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN

REVISED FORECASTS AND PROJECTIONS FOR 2007 REVENUE REQUIREMENTS AND OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-10 INDEX

2006 PROJECTIONS

Terasen Gas is projecting a 2006 return on common equity of 10.098%, or 1.298% higher than the authorized return of 8.800%. This is due primarily to productivity improvements made possible by the integration activities of the Company with TGVI which were facilitated by the performance based rate regulation (PBR) settlement. Under the PBR, which includes an earnings sharing mechanism, Terasen Gas is to share pre-tax earnings variances between authorized level of earnings as determined annually under the settlement and the actual earnings of the utility on a 50:50 basis with its customers. Accordingly, the customers' portion of the 2006 incentive earnings surplus is projected to be $8.2 million on a pre-tax basis. Details in support of this calculation can be found on Page 6 of this Tab.

Terasen Gas proposes to distribute $12.7 million to customers, representing the projected 2006 earnings surplus sharing plus a true up of prior year's earnings sharing, in 2007 via a rider.

TERASEN GAS INC.
UTILITY RATE BASE
SCHEDULE II
($000)

Line No.	Description	2006 Approved	2006 Projected	Difference	Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in service, Beginning	$3,067,485	$3,020,621	($46,864)	
2	CPCN's	4,564	4,336	(228)	
3					
4	Additions/Transfers	125,924	112,022	(13,902)	
5	Disposals/Retirements	(56,345)	(70,336)	(13,991)	
6	Plant in service, Ending	$3,141,628	$3,066,643	($74,985)	
7					
8	Add - Intangible plant	837	837	0	
9		$3,142,465	$3,067,480	($74,985)	
10					
11	Contributions in aid of construction	(137,019)	(141,559)	(4,540)	
12					
13	Less - Accumulated depreciation / amortization	(671,378)	(635,900)	35,478	
14					
15	Net plant in service, Ending	$2,334,068	$2,290,022	($44,046)	
16					
17	Net plant in service, Beginning	$2,302,480	$2,266,600	($35,880)	
18					
19	Net plant in service, Mid-year	$2,318,274	$2,278,311	($39,963)	
20	Adjustment to 13-month average	0	(9,574)	(9,574)	
21	Work in progress, no AFUDC	11,902	5,012	(6,890)	
22	Sub-total	2,330,176	2,273,749	(56,427)	
23					
24	Construction advances	(11)	(3)	8	
25	Unamortized deferred charges	13,109	11,118	(1,991)	
26	Cash working capital	(29,050)	(21,789)	7,261	
27	Other working capital	194,361	167,373	(26,988)	
28	Deferred income tax, mid-year	(364)	(364)	0	
29	LILO Benefit	(2,312)	(2,411)	(99)	
30	**Utility rate base**	$2,505,909	$2,427,673	($78,236)	

TERASEN GAS INC.
UTILITY INCOME AND EARNED RETURN
($000)

Line No.	Description	2006 Approved	2006 Projected	Difference	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUMES (TJ)**				
2	Sales	116,140	113,092	(3,048)	
3	Transportation	98,287	98,407	120	
4	Total	214,427	211,499	(2,928)	
5					
6	Average Rate per GJ				
7	Sales	$13.539	$12.705	($0.834)	
8	Transportation	$0.751	$0.761	$0.010	
9	Average	$7.677	$7.148	($0.529)	
10					
11	**UTILITY REVENUE**				
12	Sales - Present Rates	$1,555,107	$1,436,889	($118,218)	
13	- Increase / (Decrease)	17,318	0	(17,318)	
14	Transportation - Present Rates	71,360	74,925	3,565	
15	- Increase / (Decrease)	2,458	0	(2,458)	
16	**Total Revenue**	1,646,243	1,511,814	(134,429)	
17					
18	Cost of Gas Sold (Including Gas Lost)	1,151,571	1,027,996	(123,575)	
19	**Gross Margin**	494,672	483,818	(10,854)	
20	RSAM Revenue	0	9,563	9,563	
21	**Adjusted Gross Margin**	494,672	493,381	(1,291)	
22					
23	Operation & Maintenance	167,091	158,559	(8,532)	
24	Vehicle Leases	1,804	1,872	68	
25	Property Tax	41,379	41,379	0	
26	Depreciation and Amortization	83,894	79,488	(4,406)	
27	Other Operating Revenue	(24,837)	(22,999)	1,838	
28		269,331	258,299	(11,032)	
29	Utility Income before Income Taxes	225,341	235,082	9,741	
30	Income Taxes	38,977	42,148	3,171	- Tab A-10, Page 4
31	**EARNED RETURN**	$186,364	$192,934	$6,570	
32	**UTILITY RATE BASE**	$2,505,909	$2,427,673	($78,236)	- Tab A-10, Page 2
33					
34	**RETURN ON RATE BASE**	7.437%	7.947%	0.510%	

TERASEN GAS INC.
INCOME TAXES
SCHEDULE III
($000)

Line No.	Description	2006 Approved	2006 Projected	Difference	Reference
	(1)	(2)	(3)	(4)	(5)
1	CALCULATION OF INCOME TAXES				
2	Earned Return	$186,364	$192,934	$6,570	
3	Deduct - Interest on Debt	(109,168)	(107,133)	$2,035	
4	Add - Non-Tax Deductible Expense (Net)	(1,348)	(1,315)	33	
5					
6	Accounting Income After Tax	$75,848	$84,486	$8,638	
7	Deduct: Timing Differences	(6,115)	(8,316)	(2,201)	
8	Add: Large Corporation Tax	1,885	1,778	(107)	
9					
10	Taxable Income After Tax	$71,618	$77,948	$6,330	
11					
12	Income Tax Rate (Current Tax)	34.120%	34.120%	0.000%	
13	1 - Current Income Tax Rate	65.880%	65.880%	0.000%	
14					
15	Taxable Income Before Income Tax	$108,710	$118,318	$9,608	
16	Add - Amount Required to Provide for				
17	Deferred Income Tax	0	0	0	
18					
19	Taxable Income	$108,710	$118,318	$9,608	
20					
21	Income Tax				
22	Current	$37,092	$40,370	$3,278	
23	Deferred Income Tax	0	0	0	
24	Large Corporation Tax	1,885	1,778	(107)	
25					
26	Total	$38,977	$42,148	$3,171	- Tab A-10, Page 3

TERASEN GAS INC.
RETURN ON CAPITAL
SCHEDULE IV
($000)

Line No.	Description	2006 Approved	2006 Projected	Difference	Reference
	(1)	(2)	(3)	(4)	(5)
1	Unfunded debt	$195,922	$145,068	($50,854)	
2	proportion	7.82%	5.98%	-1.84%	
3	rate of return	4.000%	4.000%	0.000%	
4	return component	0.31%	0.24%	-0.08%	
5					
6	Long term debt	$1,432,919	$1,432,919	$0	
7	proportion	57.18%	59.02%	1.84%	
8	rate of return	7.072%	7.072%	0.000%	
9	return component	4.04%	4.17%	0.12%	
10					
11	Preference shares	$0	$0	$0	
12	proportion	0.00%	0.00%	0.00%	
13	rate of return	0.000%	0.000%	0.000%	
14	return component	0.00%	0.00%	0.00%	
15					
16	Common equity	$877,068	$849,686	($27,382)	
17	proportion	35.00%	35.00%	0.00%	
18	rate of return	8.800%	10.098%	1.298%	
19	return component	3.08%	3.53%	0.45%	
20					
21					
22		$2,505,909	$2,427,673	($78,236)	
23					
24					
25	Return on rate base	7.437%	7.947%	0.510%	- Tab A-10, Page 3
26					
27					
28	Utility rate base	$2,505,909	$2,427,673	($78,236)	- Tab A-10, Page 2

TERASEN GAS INC.
EARNINGS SHARING CALCULATION
($000)

Line No.	Description		2006 Projected	Reference
	(1)		(2)	(3)
1	Utility rate base		$2,427,673	- Tab A-10, Page 2
2				
3	Common Equity Component	35.0%	849,686	- Tab A-10, Page 5
4				
5				
6	Achieved ROE on Common Equity		10.098%	- Tab A-10, Page 5
7				
8	Authorized ROE on Common Equity		8.800%	- Tab A-10, Page 5
9				
10	ROE Surplus / (Deficit)		1.298%	
11				
12	After Tax Surplus Available for Sharing		$11,029	
13				
14				
15	Customers' 50% Share of Surplus (net-of-tax)		$5,514	
16				
17				
18	**Customers' 50% Share of Surplus (pre-tax)**		**$8,231**	

Other Advance Information Pertaining to the Terms of the 2004-2007 PBR Settlement

FIVE YEAR MAJOR CAPITAL PLAN

1.0 INTRODUCTION

This section constitutes Terasen Gas' Five Year Major Capital Plan. In addition to this information, Terasen Gas has also submitted its capital budget and forecast for 2006.

Terasen Gas has segmented Capital Plans as follows:

Regular Capital Plan

- Customer Driven Capital, and
- Non-Customer Driven Capital.

Major Capital Plan

- Capital Projects that do not require a Certificate of Public Convenience and Necessity ("CPCN"),
- Approved CPCN Capital Projects, and
- Anticipated CPCN Capital Projects.

Regular Capital includes forecast Capital Expenditures for non-CPCN projects that are both above and below $1 million. These expenditures have been categorized into either customer driven capital or non-customer driven capital. Regular Capital excludes Capitalized Overheads, Contributions In Aid of Construction ("CIAC"), and Allowance for Funds Used During Construction ("AFUDC").

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. As outlined on page 31 of the Decision accompanying Order G-7-03 in respect of the Terasen Gas 2003 Revenue Requirement, *"Projects with budgets greater than $5 million are generally reviewed through a CPCN process and are excluded from regular capital."*

1.1 Five Year Regular Capital Plan

The following table identifies the cost forecasts for regular capital expenditures in the current year, 2006 and 2007 to 2011. For the purposes of this Five Year Capital Plan, Regular Capital has categorized capital expenditures as follows:

Capital Additions "Customer Driven" Capital

- Mains
- Services
- Meters for New Customer Additions

Other Regular Capital

- Meter Replacements
- Transmission Plant
- Distribution Plant
- IT Capital
- Non-IT Capital

Table 1 includes a comparison of the 2006 Budget versus Projection for 2006 as well as capital expenditure forecasts for the period 2007 to 2011.

Table 1 - Forecast of Regular Capital Expenditure Targets (2006 - 2011)

	2006 Budget	2006 Projection	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast
Forecasted Year End Customer Additions	12,718	12,755	13,160	12,399	12,633	13,285	14,276
Customer Driven Capital							
Mains	6,611	6,964	7,728	7,428	7,722	8,285	9,083
Services	12,143	14,247	15,552	15,005	15,655	16,858	18,550
Meters (Customer Additions)	3,913	4,324	4,172	4,048	4,249	4,602	5,093
	22,667	**25,536**	**27,452**	**26,481**	**27,625**	**29,744**	**32,727**
Other Regular Capital							
Meters - Replacement	12,292	11,404	12,327	19,063	19,976	20,933	21,936
Transmission Plant	6,363	10,037	6,401	11,652	4,841	5,063	5,164
Distribution Plant	16,921	10,555	8,806	9,184	7,793	7,949	8,108
IT	10,500	9,920	12,742	10,736	11,038	11,246	11,471
Non-IT	11,692	13,640	11,946	12,222	12,466	12,716	12,970
	57,767	**55,556**	**52,222**	**62,857**	**56,113**	**57,906**	**59,649**
Total Regular Capital	**80,435**	**81,092**	**79,673**	**89,339**	**83,739**	**87,650**	**92,376**

Figures exclude AFUDC and Capitalized Overheads.

1.2 Revisions to the 2006 & 2007 forecast since the 2005 Annual Review

Terasen Gas is aware that the figures provided for 2006 and subsequent years differ from those presented in the 2005 Annual Review. For the convenience of readers, a high level explanation of how costs differ from the 2005 Annual Review Major Capital Plan - Scenario A, ("2005 Five Year Capital Plan") is provided below for the remaining years of the current PBR (2006 and 2007). The comparison to Scenario A, as opposed to Scenario B has been used because Scenario A was based upon the assumption that the long-term commodity price growth pattern would follow a growth rate roughly corresponding with the three year period leading up to Autumn 2005 at which point supply shortfalls caused the natural gas commodity price to significantly increase.

Scenario B assumed that the significant increase in natural gas commodity prices experienced during and after the 2005 hurricane season would be sustained. While a commodity spike for Natural Gas was experienced in Autumn 2005, natural gas commodity prices have significantly decreased since that period and at the time of submission appear to be following a growth rate consistent with the period prior to Autumn 2005. For reference, a copy of the Terasen Gas 2005 Annual Review, Five Year Capital Plan (Scenarios A and B) can be found in Section B-1, Attachment A.

When compared with the figures presented in the 2005 Five Year Capital Plan, Total Regular Capital, the year-end forecast for 2006 and 2007 is higher by 0.8% and 5.1% respectively. On an aggregate basis over the remaining years left in the current PBR (2006 & 2007), the increase in anticipated capital required when compared with the 2005 Five Year Capital Plan is approximately 2.9% or $4.6 million. Below is an explanation of the primary driver(s) of forecast revisions.

Current net customer addition forecasts for Terasen Gas can be found in Table 1 above. When compared with the forecasts presented in the 2005 Five Year Capital Plan, Section 4.1, Scenario A, Customer Driven Capital is forecast to be approximately $2.8m and $4.9 million higher for 2006 and 2007 respectively. These increases are driven in part by changes from the customer forecasts presented at the Annual Review in 2005. Terasen Gas now forecasts an additional 37 customers in 2006 and an additional 884 customers in 2007. However, the increase in Customer Driven Capital is primarily driven by an increase in the recently experienced and anticipated mains and service expenses. This increase is attributed to a number of factors, most notably contractor price increases. The impact of these higher forecast costs is anticipated to be partially offset by increased CIAC associated with the new customer additions.

For 2006, total expenditures for Other Regular Capital are expected to be approximately $2.2 million lower than anticipated for 2006 in the 2005 Five Year Capital Plan. This difference is due to a number of factors, three of which account for most of the difference.

Firstly, Distribution Plant is currently forecast at a level approximately $6.2 million less than previously forecast. The reduction in distribution plant expenditures is attributed to the following:

- $4.9 million was budgeted to perform upgrades to the Vancouver Low Pressure System. This work later became part of a CPCN project to replace the Vancouver

Low Pressure system, which was approved by Commission on June 26, 2006 in Order No. C-2-06.

- $2.3 million in Distribution System Improvements were budgeted for completion in 2006. However, the capital improvements identified were misallocated and should have been allocated to the Transmission system. The transfer of these expenditures from Distribution to Transmission results in a $2.3 million decrease to Distribution costs and an equal offsetting increase in the 2006 Transmission expenditure forecast.
- All other Distribution System Integrity expenditures are forecast to be approximately $1 million higher than last years forecast. This variance is primarily caused by increases to forecast regulator station expenditures in 2006.

Secondly, replacement meter costs are currently forecast to be $0.9 million less in 2006 than was originally anticipated.

Thirdly, forecast cost reductions are partially offset by approximately $3.6 million in unforeseen Transmission system integrity costs, which relates to the following unanticipated expenditures and allocations:

- $2.3 million increase due to the transfer of projects from Distribution to Transmission system categorization,
- $0.7 million for replacement of electrostop equipment,
- $0.2 million for reinforcement of unplanned pipeline washout near Creston, and
- $0.5 million required for Transmission Line relocation in Surrey at 176th Street and Fraser Highway.

For 2007, Other Regular Capital expenditures are expected to be approximately $1 million lower than anticipated in the 2005 Five Year Capital Plan. This decrease is primarily due to a $0.5 million decrease in anticipated replacement meter costs, an $0.8 million reduction in IT expenditures, and a $0.2 million reduction in Distribution expenditures. These reductions are offset by a $0.5 million increase in non-IT expenditures, which is primarily attributable to an upgrade of its Supervisory Control And Data Acquisition ("SCADA") systems, of which $0.4 million has been budgeted in 2007 for that project. This project is discussed in further detail in 2.1.7.

2. Five Year Major Capital Plan

2.1 Major Capital Projects that do not require a CPCN

Table 2 identifies the forecast of costs for major capital projects not subject to CPCN applications for the current year and the period 2007 - 2011.

In the table below, Transmission and Distribution projects are differentiated as either capacity shortfall projects required to maintain minimum gas system pressures in the respective gas systems or as system modification projects. IT projects are categorized as either upgrades/enhancements, replacements, or new applications.

Table 2 – Forecast of Major Capital Projects not requiring a CPCN (2006 – 2011)

Project Description	Project Category	2006 Budget	2006 Projected	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast
Transmission Plant								
Prince George #2 Lateral Replacement	Capacity Shortfall	1,020	625	1,100	-	-	-	-
Tilbury LNG Plant - Coldbox Upgrade	Replacement	-	100	750	2,250	-	-	-
Secondary Containment	System Modification	2,389	2,484	-	-	-	-	-
Golden Ears Bridge Project (Transmission Portion)	System Modification	-	-	600	700	-	-	-
Kootenay River Crossing at Shoreacres	Replacement		100	50	2,950			
Columbia River Crossing at Brilliant	Replacement		100	50	2,950			
Scada Upgrade	Upgrade/Enhancement	-	-	400	1,200	-		
Distribution Plant								
Clearbrook-Riverside Road Loop, Abbotsford	Capacity Shortfall	-	-	-	1,192	-	-	-
Golden Ears Bridge Project (Distribution Portion)	System Modification	-	-	300	300	-	-	-
IT								
Order Fulfillment Enhancement (Annual Program)	Upgrade/Enhancement	1,010	446	520	116	-	-	-
Mobile UP Replacement	Replacement	1,863	225	3,600	270	-	-	-
AM/FM GIS for Transmission	New Application	547	547	-	-	-	-	-
Desktop & Laptop Refresh (Annual Program)	Replacement	1,070	1,070	591	950	-	1,767	
Café (Customer Attraction Front End)	New Application	290	360	-	-	-	-	-
SAP Core Application Upgrade	Upgrade/Enhancement	-	-	250	2,250	-	-	-
Non-IT								
No Projects Identified								
		8,188	**6,057**	**8,211**	**15,128**	**-**	**1,767**	**-**

2.1.1 Transmission Plant - Prince George #2 Lateral Replacement

Construction on this project is planned to commence in 2006 and be completed in 2007. It consists of replacing a 4.0 km section of the existing 168.3 mm Outside Diameter ("OD") pipeline with 219.1 mm OD pipeline to support firm load growth and address operating concerns such as shallow pipe, proximity to road ditches and lack of a dedicated right of way. The estimated cost of this project is approximately $1.7 million (excluding AFUDC) and is expected to be in service in 2007. A discussion of this project can be found in Section B-1, Page 5 of the Terasen Gas 2005 Annual Review materials.

2.1.2 Transmission Plant – LNG Coldbox Upgrade

The Liquefied Natural Gas ("LNG") Coldbox is part of the plant component at the Terasen Gas Tilbury LNG Facility. The LNG Coldbox is the plant component that reduces gas temperature to -260 F, thereby converting natural gas into LNG. The existing plant was built in 1970-1971.

The LNG Coldbox consists of a number of very complex shell and tube, spiral-wound heat exchanges. A number of the tubes in one heat exchanger failed in early 2005. Repairs were successful but very challenging. A materials engineering investigation was completed as to cause and likelihood of additional failures in future. This report stated that further tube failures will occur.

As a non-operational Coldbox will result in Terasen Gas not being able to produce LNG, Terasen Gas plans to spend approximately $3.1 million (excluding AFUDC) for replacement of this plant. Preliminary work is expected to commence in 2006 and be completed by 2008.

2.1.3 Transmission Plant - Secondary Containment

In 2002 Terasen Gas embarked on a five year program to construct secondary containment facilities. The total estimated cost of this project is approximately $9.4 million (excluding AFUDC) and is expected to be complete in 2006. The 2006 expenditure is forecasted to be approximately $2.5 million (excluding AFUDC). A discussion of this project can be found in Section B-1, Page 7 of the Terasen Gas 2005 Annual Review materials.

2.1.4 Transmission and Distribution Plant - Golden Ears Bridge Project

TransLink, the Greater Vancouver Transportation Authority, is developing a new six-lane bridge across the Fraser River in the 200th Street corridor to improve the movement of people and goods in the Greater Vancouver region and is being designed to link communities on the south side of the Fraser River (Langley and Surrey) with the north-side communities of Maple Ridge and Pitt Meadows. Construction of the Golden Ears Bridge commenced on June 27, 2006 and the bridge is expected to open to traffic in mid 2009.

TransLink and Terasen Gas have been involved in ongoing discussions regarding this project and as a result Terasen Gas has conducted conceptual and preliminary investigations into system modification which will be required as a result of this project. Based upon this information, Terasen Gas currently projects that total system modifications will cost approximately $1.9 million (excluding AFUDC).
Of particular significance are two replacements of the 323 mm Livingston – Coquitlam transmission pressure pipeline, costing approximately $1.3 million (excluding AFUDC), due to encroachment of the bridge works near the pipeline in areas of soft soils. The other alterations to the gas system are routine relocations of distribution pressure mains and services.

As this system modification is being driven by TransLink, Terasen Gas will attempt to minimize the total costs to be incurred by the Company by charging back TransLink a portion of the total overall costs. At this time, Terasen Gas has insufficient information to forecast the total amount it expects to recover from TransLink.

2.1.5 Transmission Plant - Kootenay River Crossing near Shoreacres

An aerial crossing of the Kootenay River on the Savona – Nelson Mainline between Castlegar and Nelson near Shoreacres has been identified as requiring extensive rehabilitation. This structure was constructed in 1957 and has extensive cable and pipe corrosion. This structure must be repaired or replaced in order to ensure continued gas service to Nelson. Horizontal Directional Drilling (“HDD”) is currently being considered as an alternative to an aerial crossing and preliminary investigations are being conducted in 2006. Preliminary project planning is anticipated to commence in late 2006 with work being completed in 2008. Preliminary cost estimates are approximately $3.1 million (excluding AFUDC).

2.1.6 Transmission Plant - Columbia River Crossing near Brilliant

An aerial crossing of the Columbia River on the Savona – Nelson Mainline between Castlegar and Nelson near Brilliant has been identified as requiring extensive rehabilitation. This structure was constructed in 1957 and has extensive cable and pipe corrosion. This structure must be repaired or replaced in order to ensure continued gas service to Nelson. HDD is also being considered as an alternative to an aerial crossing in this location. Preliminary investigations are being conducted in 2006. Preliminary project planning is anticipated to commence in late 2006 with work being completed in 2008. Preliminary cost estimates are approximately $3.1 million (excluding AFUDC).

2.1.7 Transmission Plant - SCADA System Upgrade

The SCADA system operates controls and monitors Terasen Gas' transmission and compression facilities in British Columbia. Vendor support of the current version (6.0) of the SCADA application is expected to expire at the end of 2008. An upgrade to the next supported version is therefore required to be in service in 2008. The total estimated cost of this project is $1.6 million (excluding AFUDC). Implementation is expected to begin in 2007 and will be in service in 2008. A discussion of this project can be found in Section B-1, Page 15 of the Terasen Gas 2005 Annual Review materials.

2.1.8 Distribution Plant – Clearbrook, Riverside Road, Abbotsford

This project consists of a 1.6 km loop of NPS 12 (323mm OD) pipeline operating at 275 psig (1,900 kPa). The estimated cost of this project is $1.2 million (excluding AFUDC). This project is currently planned to be constructed and in service in 2008. A discussion of this project can be found in Section B-1, Page 5 of the Terasen Gas 2005 Annual Review materials.

2.1.9 IT Capital – Order Fulfilment Upgrades

The Order Fulfilment business process is modelled within SAP and is planned to provide upgraded functionality to bridge process gaps and to streamline the receipt and processing of customer generated orders. The estimated cost of this project is $1.1 million (excluding AFUDC). Originally, this project was anticipated to be completed in 2006 at a cost of $1.0 million. It is now expected to be rolled out in smaller increments and completed by the end of 2008. A discussion of this project can be found in Section B-1, Page 13 of the Terasen Gas 2005 Annual Review materials.

2.1.10 IT Capital - MobileUP Replacement

The MobileUP application is currently used for the Mobile Data Dispatch of customer service activities and the transfer of customer meter and billing information to the Energy Customer Information System. In 2006 Terasen Gas is conducting a preliminary scoping exercise which is expected to continue into 2007. In 2007 and 2008, following the completion of that exercise, Terasen Gas is intending to replace the current application in order to align customer service activities with construction activities and to implement a consistent set of processes supported by a single system.

Costs associated with this program are currently estimated to be approximately $4.6 million (excluding AFUDC). Based upon a 90% allocation of total costs, Terasen Gas costs are approximately $4.1 million*. A discussion of this project can be found in Section B-1, Page 14 of the Terasen Gas 2005 Annual Review materials.

** In 2006, Terasen Gas began to allocate capital costs for IT projects which are of benefit to both Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. to both companies. For projects in support of ongoing customer service and support activities, allocations have based upon a 90% / 10% apportionment respectively for customers. This split was based in part on the number of staff members at both companies and on the number of customers served by each company. For projects supporting new customer attachment activities, an 80% / 20% apportionment has been used. This apportionment is based upon customer growth projections for each company over a 5 year period and is currently only applicable to one project, Café (Customer Attraction Front End). See 2.1.13.*

2.1.11 IT Capital AM/FM GIS for Transmission

Automated Mapping/Facilities Management ("AM/FM") for Transmission is an integrated Geographical Information System ("GIS") and facilities management solution for the basic Transmission records and business processes. It will support business processes for: Pipeline Operations; Right of Way Property Management; Transmission Planning and Transmission Support. The proposed solution is intended to extend the existing as-built paper and computer-assisted drafting ("CAD") based record system with the enhanced features of an Automated Mapping system. The current estimated total costs for this project is approximately $1.7 million (excluding AFUDC) and it is anticipated to be complete in 2006.

2.1.12 IT Capital – Desktop and Laptop Refresh

This is an annual recurring program to replace desktop and laptop computers. The number of units replaced on an annual basis varies depending of how long the computers have been in service. The estimated cost of units to be refreshed in 2006 is $1.1 million (excluding AFUDC) and the 2006 program is expected to be completed in 2006.

The next projected year that the number of desktop and laptop units required to be replaced exceeds $1.0 million is in 2010. The current forecast expenditure for 2010 is $1.8 million (excluding AFUDC). A discussion of this program can be found in Section B-1, Page 14 of the Terasen Gas 2005 Annual Review materials.

2.1.13 IT Capital – Café

Customer Attraction Front End ("Café") supports a number of key business units and processes in meeting customer growth targets. The technology functionality includes lead capture and tracking, distribution of marketing content and improved construction order processing for all companies. In 2006, this application was rolled out to the appropriate business units. Total costs attributable to the project are in process of being finalized and Terasen Gas anticipates total project costs to be approximately $1.8 million (excluding AFUDC). Based upon the allocation policy for growth IT projects of benefit to both Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. ("TGVI"), total costs attributable to Terasen Gas are estimated to be approximately $1.5 million, with the remainder to be allocated to TGVI.

2.1.14 IT Capital – SAP Core Application Upgrade

SAP is the enterprise application that supports business processes to: Operate and Maintain; Order Fulfilment; Meter Management and Supply Chain. It also supports other back-office functions such as: Payroll; Finance and Performance Reporting. Vendor support of the current version of the SAP application (R3 v4.6C) expires in the fourth quarter of 2006. An upgrade to the next supported version is therefore required to be in service in 2007. The total estimated cost of this project is $2.5 million (excluding AFUDC). This project is expected to be completed in 2008. A discussion of this project can be found in Section B-1, Page 14 of the Terasen Gas 2005 Annual Review materials.

2.2 Major Capital Projects that require a CPCN

Table 3 identifies the forecast of costs for major capital projects subject to CPCN applications for 2006 to 2011.

Table 3 Forecast of Major Capital Projects subject to CPCN Applications (2006 – 2011)

Project Description	2006 Budget	2006 Projected	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast
Approved CPCN's & Deferral Accounts							
Vancouver LP Replacement	-	5,674	8,706	8,723			
Residential Unbundling	9,000	5,140	7,063	-	-	-	-
	9,000	**10,814**	**15,769**	**8,723**	**-**	**-**	**-**
Anticipated CPCN's & Deferral Accounts							
Mission IP Pipeline System Upgrade	5,800	949	7,345	76	-	-	-
Gateway Project	-	187	11,900	9,300			
Fraser River SBSA Rehabilitation	-	-	1,500	7,500	-		
	5,800	**1,136**	**20,745**	**16,876**	**-**	**-**	**-**
Total CPCN's & Deferrals	**14,800**	**11,950**	**36,513**	**25,599**	**-**	**-**	**-**

2.2.1 Approved CPCN – Vancouver LP System Replacement

Approximately 95km of Low Pressure ("LP") mains are still in service in densely populated and established areas of Vancouver. The LP system serves approximately 7,100 customers including: commercial establishments; residences; schools and hospitals. It is planned to replace the steel/iron LP system with a polyethylene system, operating at Distribution Pressure of 420 kPa (60 psig), over a 3 year period commencing in 2006 with completion in late 2008.

In May 2006, Terasen Gas submitted a CPCN Application to complete this work. In its application, Terasen Gas projected that it would cost approximately $23.1 million (excluding AFUDC) to complete the 3 year replacement program. This CPCN application was approved by Commission on June 26, 2006 in Order No. C-2-06.

2.2.2 Approved CPCN - Residential Unbundling Program

Since the release of the BC Energy Policy in 2002, Policy Action #19 stating that "Natural gas marketers will be allowed to sell directly to small volume customers", Terasen Gas has been facilitating providing commodity choice for small volume customers. The Commercial Commodity Unbundling program was launched in November 2004 with Residential Commodity Unbundling tentatively targeted to start in 2007.

With direction from the Commission, Terasen Gas completed a detailed design review and cost estimate using external consultants as part of its Pre-Scoping and Scoping Phases for Residential Unbundling between July 2005 and March 2006. To complete this work, the Commission approved $1.4 million in funding in 2005 to be recorded in a deferral account. On April, 2006, Terasen Gas submitted an application to enhance its business processes and systems as required to support the provision of commodity choice to residential customers in the Terasen Gas service area. In its application it specifically requested the following:

- Implement Commodity Unbundling for all residential customers in its service territory, excluding Fort Nelson and Revelstoke, effective November 1, 2007.
- Capital Expenditures of $11.1 million (in addition to the $1.4 million approved for the pre-scoping and scoping phases) to implement the Residential Unbundling program.

On August 14, 2006 Commission issued Order C-6-06 approving this CPCN. In total, this project is currently estimated at $12.5 million and is scheduled for implementation in 2007.

2.2.3 Current CPCN Application - Mission IP System Upgrade

It has been determined that portions of the existing Intermediate Pressure (“IP”) pipeline adjacent to the Mission Highway Bridge as well as the Mission Regulator Station are at risk due to ground movement from seismic induced soil liquefaction and slippage associated with a seismic event of less than 1:100.

Terasen Gas believes that potential consequences of a relatively minor seismic event could result in a pipeline rupture and loss of gas service for approximately 10,000 Terasen Gas customers. Such an event would also trigger an extensive requirement for resources, both human and material, to undertake repairs. Terasen Gas is of the view that this situation poses increased safety risks to customers, employees, its contractors, and the general public.

On June 20, 2006, Terasen Gas applied for approval of a CPCN to complete a Seismic Upgrade of the Mission IP System. In order to address these seismic concerns, Terasen Gas is seeking approval of the following:

- Replacement of approximately 2 km of existing 168 mm (NPS 6) and 219 mm (NPS 8) OD IP pipeline, a portion, 219 mm (NPS 8), being on the Mission Highway Bridge, with approximately 2 km of 323 mm (NPS 12) OD IP pipeline installed across the Fraser River using HDD technology;
- Installation of approximately 1000 metres of 219 mm (NPS 8) polyethylene distribution pressure main; and
- Removal of the Mission Regulator Station.

Terasen Gas is currently conducting a feasibility assessment on the proposed HDD route. Based upon the assumption that this CPCN application is approved in 2006, Terasen Gas estimates that the project will be completed in November, 2007. Terasen Gas currently forecast that the project will cost approximately $8.4 million (excluding AFUDC).

2.2.4 Anticipated CPCN - Gateway Project

The Gateway Project was established by the Province of British Columbia in response to the impact of growing regional congestion, and to improve the movement of people, goods and transit throughout Greater Vancouver. The Gateway Program includes three components:

- Port Mann / Highway 1 Project – This proposal includes twinning the Port Mann Bridge, upgrading interchanges and improving access and safety on Highway 1 from Vancouver to Langley.
- The South Fraser Perimeter Road Project is a proposed new four-lane, 80 km/h route along the south side of the Fraser River extending from Deltaport Way in southwest Delta to the Golden Ears Bridge connector road in Surrey/Langley.
- The North Fraser Perimeter Road Project is a proposed set of improvements on existing roads to provide an efficient, continuous route from New Westminster to Maple Ridge.

The Gateway Project is being managed by the Ministry of Transportation ("MoT"). The MoT and Terasen Gas have been involved in ongoing discussions regarding this project and as a result Terasen Gas has conducted conceptual and preliminary investigations into system modification which will be required. Based upon this preliminary information, Terasen Gas currently projects that total system modifications will cost approximately $21.4 million (excluding AFUDC). Terasen Gas will attempt to minimize the costs to be incurred by the Company through negotiations with the MoT. Generally due to permit conditions, Terasen Gas incurs the costs of alteration of its existing facilities located in land already under MoT jurisdiction. When Terasen Gas must alter facilities outside of lands under the jurisdiction of the MoT, it is often able to have the MoT assume responsibility for some or all of the costs. At this time, Terasen Gas is not in a position to fully validate nor quantify the extent to which the MoT will assume costs attributable to this project.

Terasen Gas facilities are impacted by all three components of the Gateway Program; however the most significant impact is caused by the construction of the South Fraser Perimeter Road Project through the municipality of Delta. The modifications to Terasen Gas's systems will include:

- Relocation of the Benson Regulator Station and the associated inlet and outlet pipelines as a result of the construction of a major highway interchange in an area of soft soil. Preliminary cost estimates are forecast to be approximately $6.1 million (excluding AFUDC).

- Relocation of transmission lines at 76th Street, Alexander Rd, and Nordel Way due to nearby highway encroachment and construction in areas of soft soils. Preliminary cost estimates are forecast to be approximately $11.4 million (excluding AFUDC).

Terasen Gas is not in a position to file a CPCN for this project at this time. Terasen Gas anticipates filing a CPCN in early 2007.

2.2.5 Anticipated CPCN – Fraser River South Bank South Arm (“SBSA”) Crossing

Following an engineering assessment of the current 20” & 24” underwater Transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver & Richmond, an opinion from the firm who conducted the assessment indicated in 2006 that both the underwater crossings and the adjacent south bank require extensive rehabilitation to ensure they do not pose a risk in the event of a seismic occurrence. Terasen Gas is seeking a second opinion on the matter. Should rehabilitation work be deemed necessary, Terasen Gas intends to file a CPCN by mid-2007 with an expected completion in 2008. Project costs are currently estimated to be $9 million (excluding AFUDC).

TAB B-1 FIVE YEAR MAJOR CAPITAL PLAN

ATTACHMENT A – 2005 ANNUAL REVIEW, FIVE YEAR CAPITAL PLAN (SCENARIOS A AND B)

4.0 COST PROJECTIONS FOR REGULAR CAPITAL AND CPCN'S

4.1 Cost Projections for Regular Capital

This section identifies the cost projections for regular capital expenditures in 2006 – 2010. The projections of capital expenditures are based on the Company's internal challenge targets, which differ from the formulaic driven capital expenditures that are added to rate base (as per Section A, Tab 3, Page 4).

The economic outlook for the Province over the next 5 years is predicted to be fairly strong with GDP growing annually at approximately 3%. Based on this, it is anticipated that housing starts will continue at rates similar to those projected for 2006. However, it is also expected that the trend will continue whereby the proportion of multi-family dwellings will increase and the proportion of single family dwellings will decrease over time. Additionally, Terasen Gas believes that uncertainty with respect to commodity costs and resulting competitiveness v. alternative energy sources, will continue to place pressure on the Company's customer capture rates. Although current long term forward strip prices and long term gas costs forecasts suggest that commodity prices may fall off somewhat from their current levels, the forecast long term prices are significantly greater than what they were even one year ago. The effect that sustained higher gas prices will have on customer capture is uncertain. However, the Company anticipates that customer additions would fall off in the event of a sustained higher gas price environment.

In response to this degradation of the competitiveness vs. alternative energy sources, the Company has been pursuing strategies and focusing sales and marketing efforts in an attempt to maintain or increase customer capture rates in certain market segments. The Company anticipates that it will have some success in these efforts and has reflected in its challenge targets modest improvements in customer capture, although there is a large degree of uncertainty with respect to the potential success of these efforts.

The Company presents below two alternative scenarios with respect to customer growth and corresponding capital additions. The Company submits that each forecast is reasonable in light of the tremendous uncertainty facing the company and its competitive landscape over the next 5 years and beyond. The difference between the two scenarios is the underlying gas cost forecasts and resulting impacts on customer capture rates that the Company anticipates may occur. Under both scenarios it is assumed that the Company will continue pursuing its sales and marketing efforts, with modest success, in increasing customer capture in certain market segments, and as such the additions forecast represents the Company's challenge targets.

In the first scenario (Scenario A below), longer term commodity drop and customer capture rates for the period are consistent with levels currently experienced, with some modest increases reflecting sales and marketing efforts.

In the second scenario, it is assumed that commodity prices are sustained at the current high levels with the result that customer capture rates will be eroded. Accordingly, Terasen Gas has prepared this alternative forecast of customer additions and capital expenditures (Scenario B below) that reflects a reduction in the number of customers captured of approximately 25%. The modest increases in customer capture over the forecast period related to the sales and marketing strategies described above are included in this scenario.

SCENARIO A

Cost Projections for Regular Capital Expenditure 2006-2010 - Challenge Targets

Forecasted Customer Additions - Challenge Targets	12,718	12,276	12,903	13,575	14,043
Customer Driven Capital	**2006**	**2007**	**2008**	**2009**	**2010**
Mains	6,611	6,573	7,116	7,711	8,216
Services	12,143	12,073	13,070	14,163	15,091
Meters - Customer Additions	3,913	3,890	4,212	4,564	4,863
	22,667	**22,536**	**24,398**	**26,438**	**28,170**
Other Regular Capital	**2006**	**2007**	**2008**	**2009**	**2010**
Meters - Replacement	12,292	12,865	15,983	16,792	17,659
System Integrity & Reliability					
Transmission Plant	6,363	5,932	5,145	4,841	5,063
Distribution Plant	16,921	8,999	9,449	7,793	7,949
Other Regular Capital					
Non - IT	11,692	11,946	12,222	12,466	12,716
IT	10,500	13,500	11,400	11,700	11,900
	57,768	**53,242**	**54,199**	**53,592**	**55,287**
Total Regular Capital	**80,435**	**75,778**	**78,597**	**80,030**	**83,457**

Note: All estimates exclude AFUDC

SCENARIO B

Cost Projections for Regular Capital Expenditure 2006-2010 - Challenge Targets

Forecasted Customer Additions - Challenge Targets	12,718	9,206	9,677	10,181	10,532
Customer Driven Capital	**2006**	**2007**	**2008**	**2009**	**2010**
Mains	6,611	4,929	5,337	5,783	6,162
Services	12,143	9,054	9,802	10,622	11,318
Meters - Customer Additions	3,913	2,917	3,159	3,423	3,647
	22,667	**16,900**	**18,298**	**19,828**	**21,127**
Other Regular Capital	**2006**	**2007**	**2008**	**2009**	**2010**
Meters - Replacement	12,292	12,865	15,983	16,792	17,659
System Integrity & Reliability					
Transmission Plant	6,363	5,932	5,145	4,841	5,063
Distribution Plant	16,921	8,999	9,449	7,793	7,949
Other Regular Capital					
Non - IT	11,692	11,946	12,222	12,466	12,716
IT	10,500	13,500	11,400	11,700	11,900
	57,767	**53,242**	**54,199**	**53,592**	**55,286**
Total Regular Capital	**80,435**	**70,142**	**72,497**	**73,421**	**76,413**

Note: All estimates exclude AFUDC

4.2 Cost Projections for CPCN's

The following table identifies the cost projections for major capital projects subject to CPCN applications for 2006 – 2010:

Cost Projections for Major Capital Projects Subject to CPCN Applications 2006-2010

CPCN Applications	**2006**	**2007**	**2008**	**2009**	**2010**
4.2.1 Mission Bridge IP Directional Drill	5,800	-	-	-	-
4.2.2 Residential Unbundling	9,000	16,000	-	-	-
4.2.3 Vancouver LP System Replacement	-	5,202	5,306	5,412	-
4.2.4 Nichol to Port Mann Loop	-	-	-	-	15,766
	14,800	**21,202**	**5,306**	**5,412**	**15,766**

Note: All estimates exclude AFUDC

SERVICE QUALITY ASSURANCE MECHANISM

1 INTRODUCTION

In 2003, the Commission approved the 2004 – 2007 PBR Settlement that Terasen Gas negotiated with its stakeholders. This agreement includes a commitment to maintaining specified levels of service as measured by Service Quality Indicators ("SQIs").

Terasen Gas has ten SQIs that are measured and compared against benchmarks on an annual basis. Additionally there are two directional indicators that do not have benchmarks but are designed to give an understanding of trends that may develop in these particular areas relating to customer service.

Beginning in March 2006, following the conversion of the Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW") customers to the Terasen Gas outsourced customer care and billing environment, the customer care metrics described below represent the combined experience for Terasen Gas, TGVI, and TGW customers. Terasen Gas does not believe the addition of these customers to the outsourcing arrangement will materially impact the specified service levels as the systems and processes used to support the additional customers are the same as those used to provide service to TGI customers.

2 COMPONENTS OF THE SERVICE QUALITY ASSURANCE MECHANISM

The Service Quality Assurance Mechanism includes four components:

1. A set of ten SQIs;
2. Benchmarks for each indicator, where applicable;
3. Two directional indicators; and
4. A process for reviewing Terasen Gas performance.

2.1 Service Quality Indicators and Benchmarks

2.1.1 Choice of Service Quality Indicators

SQIs are generally based on the following criteria:

- Value to customer: The indicator must represent a service or service attribute that the customer thinks is important.
- Controllable by the utility: Only those indicators over which the utility has control should be included. SQIs should not be linked to exogenous events over which management decisions have little or no influence.
- Cost effective: The information collection activities associated with the indicator must be cost effective.
- Regulated service: The indicator must represent a regulated service provided by the utility that is not generally available from competitors.
- Simplicity and transparency: The indicator should be simple to administer and results should be easy to understand and interpret.
- Prior tracking: The indicators should have been previously tracked to ensure they are stable over time and this should be considered in future evaluations.
- Quantification: The indicators must be quantifiable.
- Flexibility: The indicators should allow sufficient flexibility to allow modifications, additions and deletions as required over time.

2.1.2 History of Service Quality Indicators

The criteria described in the previous section were taken into account in establishing the SQIs for the PBR settlement in 1997. Five SQIs were used between 1998 and 2002:

1. Response time to site for emergency calls (only for the Coastal region).
2. Percent of responses within 30 seconds by a person at a call centre (only for the Coastal region).
3. Leaks per kilometre of Distribution mains due to system deterioration.
4. Transmission system annual reportable incidents.
5. Number of third party distribution system damage incidents per 1,000 housing starts.

During the 2004-2007 PBR Settlement process, the Service Quality Indicators were reviewed and substantially changed. The criteria described in the previous section were also taken into account in establishing the SQIs for the 2004 – 2007 period.

2.1.3 Choice of Benchmarks

Benchmarks are reference points against which levels of service quality can be compared. Benchmarks typically reflect either industry standards or the utility's performance over a recent prior period. Use of the utility's recent historical performance to establish a benchmark is generally used as this has the advantage of being realistic, verifiable, and representative.

2.1.4 Service Quality Indicators and Benchmarks

There were changes and additions to the SQIs as part of the 2004 – 2007 PBR Settlement. The following are individual explanations for each of the ten SQIs that were established during the 2004 – 2007 PBR Settlement to be used throughout the PBR period. Please refer to the table at the end of this section for a summary of the SQIs.

1. Emergency Response Time (Response Time Dispatched to Site for Emergency Calls)

This indicator is the average length of time after notification for a qualified utility representative to arrive on the scene of the emergency (i.e. a pulled main or a situation where gas is blowing) at any location on the Terasen Gas system both during and after working hours, including weekends. The benchmark was set at the average for the three years from 2000 to 2002: 21.1 minutes.

Year	Response Time Dispatched to Site for Emergency Calls
2006 (Jan – Aug)	21.4 minutes
2005	21.7 minutes
2004	21.6 minutes
2003	22.0 minutes
Benchmark	≤ 21.1 minutes

The 2006 current year-to-date response time of 21.4 minutes is just 18 seconds longer, or 1.4% greater, than the benchmark of 21.1 minutes. Terasen Gas expects to be at or near the 21.1 minute benchmark at year end despite the increased construction activity and corresponding increase in actual number of hit lines.

2. Speed of Answer – Emergency (Percent of Responses Within 30 Seconds by a Person - Emergency Calls)

Call answer time is a common service quality indicator for distribution utilities. Emergency Call Handling for the Lower Mainland Call Centre was a Service Quality Indicator from 1998 to 2002. The introduction of the Interior call centre allowed Terasen Gas to track the percent of responses within 30 seconds by a person for emergency calls for both the Coast and Interior since 2000. The benchmark of 95.0% is included as a performance clause in the contract with CustomerWorks. The current service level is an improvement over the three-year historical average and there has been a year over year improvement during the settlement period.

Year	Percent of Responses Within 30 Seconds by a Person for Emergency Calls
2006 (Jan - Aug)	99.0%
2005	98.8%
2004	97.9%
2003	96.3%
Benchmark	≥ 95.0%

Year to date the average speed to answer for calls in the emergency queue is 99.0%. Terasen Gas expects to be at or near this level at the end of 2006.

3. Speed of Answer – Non-Emergency (Percent Responses Within 30 Seconds by a Person – Non-Emergency Calls)

This SQI tracks the percent of responses within 30 seconds by a person for non-emergency calls including general, bill inquiries and service applications. B.C. Hydro answered the majority of Lower Mainland non-emergency inquiries prior to repatriation in July 2002. The introduction of the Interior call centre allowed Terasen Gas to track the percent of responses within 30 seconds by a person for non-emergency calls for both the Coast and Interior since 2000. The Benchmark of 75.0% is included as a performance clause in the contract with CustomerWorks and is based on the average for the three years from 2000 to 2002.

Year	Percent of Responses Within 30 Seconds by a Person for a Non-Emergency Call
2006 (Jan - Aug)	77.9%
2005	76.9%
2004	77.5%
2003	76.4%
Benchmark	≥ 75.0%

The 2006 year-to-date percentage for non-emergency speed of answer at 77.9% is an improvement over the 2005 result of 76.9% and is better than the benchmark of 75.0%. Terasen Gas is forecasting that the year end result will exceed the target of 75%.

4. Transmission System Integrity (Transmission System Annual Reportable Incidents)

This indicator is presently tracked manually and this is expected to continue, as it covers several different kinds of incidents that are reported to government.

Year	Transmission System Annual Reportable Incidents
2006 (Jan - Aug)	0
2005	3
2004	3
2003	3
Benchmark	≤ 2

The 2006 year-to-date transmission system reportable incidents of 0 compares favourably with the benchmark level of 2.

5a. Residential & Commercial Customer Billing Activity (Customer Bills Produced Meeting Activity Criteria)

This indicator is new for the 2004 – 2007 PBR. The contract with CustomerWorks contains three performance measures that are included together as sub-measures and combined to form a single service quality indicator. These sub-measures are generally described as accuracy, timeliness, and completion. The tolerance requirements for the first measure are significantly higher than the second and third, 99.9% v. 95%. As such, in order to align these sub-measures, an index score is used. The objective is to achieve a score of 5.0 or less. No historical information is available prior to 2003 but the benchmark was set based on the performance measures in the contract with CustomerWorks.

	Billing Sub-Measure	Percent Achieved (“PA”)	Adjustment Factors	Result
1	Percentage of bills accurate based upon input data	99.9%	IF [PA≥99.9%, 5000*(1-PA), 100*(1.05-PA)]	5.0
2	Percentage of bills delivered to Canada Post within two days of date that the statement file is created	95%	100 – PA	5.0
3	Percentage of customers billed within two business days of the scheduled billing date	95%	100 – PA	5.0
Benchmark	Billing Service Quality Indicator (arithmetic average of sub-measures 1 to 3)			5.0

The Adjustment Factors allow the computation of an index score using a simple average of the three results (5.0 or less is desirable).

Year	Customer Bills Produced Meeting Activity Criteria
2006 (Jan - Aug)	0.70
2005	1.97
2004	1.93
2003	2.63
Benchmark	≤ 5.0

The 2006 year-to-date result for customer bills meeting the billing composite score at 0.70 which compares very favourably to the benchmark of 5.0 and reflects an improvement over the 2005 level of 1.97. This improving trend is expected to continue through to the end of 2006. Beginning in March 2006, the determination of this score includes the experience of the TGVI and TGW customers, a base volume increase of approximately 10% over the previous reporting year. The improved results achieved to date in 2006 reflect the seamless transition of the TGVI and TGW customers into the outsourced billing environment and the quality of the conversion initiative from a billing perspective.

5b. Industrial Customer Billing Activity (Percent of Industrial Customer Bills Accurate)

This indicator is new for the 2004-2007 PBR. Historical information is only available beginning in 2003. This service quality indicator tracks the accuracy of billing for Industrial customers.

Year	Percent of Industrial Customer Bills Accurate
2006 (Jan - Aug)	99.9%
2005	99.9%
2004	96.6%
2003	99.8%
Benchmark	≥ 99.5%

The 2006 year-to-date percentage of industrial bills accurate of 99.9% is an increase over the benchmark of 99.5% and continues the strong performance in this area reflected in the 2005 results.

6. Meter Exchange Appointment Activity (Percent of Appointments Met for Meter Exchange)

This indicator is new for the 2004-2007 PBR and it tracks the percent of appointments met for meter exchange. Terasen Gas started to track this information with the introduction of the Integrated Resource Management project in late 2001, so historical information is available only since 2002. The benchmark is set at the 2002 level.

Year	Percent of Appointments Met for Meter Exchange
2006 (Jan - Aug)	94.5%
2005	94.3%
2004	93.5%
2003	92.6%
Benchmark	≥ 92.2%

The 2006 year-to-date result of 94.5% of meter exchange appointments met compares favourably to the benchmark of 92.2% and is an improvement over the 2005 level of 94.3%.

7. Industrial Meter Measurement (Industrial Meter Measurement First Report Under 10%)

This indicator is new for the 2004 – 2007 PBR. This service quality indicator tracks the percent of time when the deviation is less than 10% between the preliminary billing estimate that is first reported to an industrial customer, compared to the final amount that is billed to the customer. Industrial Shipper Agents are interested in both their daily balanced groups and their monthly balanced groups. This SQI for Industrial Meter Measurement contains both an accuracy measure (percent deviation) and a frequency measure, applied to both daily and monthly groups on a GJ-weighted basis. Customers who do not provide Terasen with a metering phone line are not included in this measure. Historical information is only available beginning in 2003. The benchmark is set at 90%.

Year	Industrial Meter Measurement First Report Under 10%
2006 (Jan - Aug)	99.2%
2005	99.5%
2004	98.0%
2003	97.4%
Benchmark	≥ 90.0%

The 2006 year-to-date result of 99.2% for industrial meter measurement far exceeds the benchmark of 90.0% and similar to the 2005 level of 99.5%.

8. Customer Satisfaction (Independent Customer Satisfaction Survey)

This indicator is new for the 2004-2007 PBR. Prior to 2005, this service quality indicator tracked customer satisfaction using three surveys conducted by parties outside Terasen Gas. A Residential Survey was conducted quarterly, while a Large Commercial Survey and a Builder/Developer Survey were conducted annually. In order to arrive at the Service Quality Indicator for the Independent Customer Satisfaction Survey, these three surveys were weighted as follows: 80% Residential, 10% Commercial and 10% Builder/Developer.

Starting in 2005, a fourth customer satisfaction study with small commercial customers[1] is included in the calculation of the Service Quality Indicator. Additionally, the formula for deriving the Residential score has been updated to reflect the level of importance customers currently place on various service attributes. The four surveys are weighted as follows: 75% Residential, 10% Large Commercial, 10% Builder/Developer, 5% Small Commercial.

High gas costs and other events beyond the control of Terasen Gas can influence this SQI. It was agreed during the 2004 – 2007 PBR Settlement that there is no performance threshold for

[1] Small commercial customers represent approximately 20% of Terasen Gas' annual revenue and approximately 9% of the total customer base.

this SQI, but that results would be considered in the context of previous results and that consideration would be given to external factors that can influence satisfaction scores.

Year	Independent Customer Satisfaction Survey[2]
2006 (Jan – Aug)	77.0%
2005	77.2%
2004	75.3%
2003	73.9%
Benchmark	N/A – results to be compared to prior years

The 2006 year-to-date Independent Customer Satisfaction Survey score of 77.0% is an improvement over the 2003 benchmark comparative of 73.9% and in line with the 2005 level of 77.2%.

9. Customer Satisfaction (Number of Customer Complaints to BCUC)

This service quality indicator is new for the 2004-2007 PBR. This indicator tracks the number of customer complaints submitted to the BCUC that the Commission then requests, either by Commission Letter or by a Complaint/Inquiry Record, that Terasen Gas provide a written response. Historical information is only available beginning in 2003. High gas costs and other events beyond the control of Terasen Gas can influence the number of complaints to the BCUC. It was agreed during the 2004 – 2007 PBR Settlement, that there is no performance threshold for this SQI, but that results would be considered in the context of previous results and consideration would be given to external factors and any relevant uncontrollable events that can influence results.

[2] The 2004 Service Quality Indicator (SQI) was originally reported as 73.9%. This figure was calculated using the formula in place at that time. In 2005, the 2004 SQI was recalculated using a formula adopted in 2005. This was to ensure that the 2004 SQI could be directly compared to the SQI for 2005 and subsequent years.

Year	Number of Customer Complaints to BCUC
2006 (Jan - Aug)	114
2005	121
2004	191
2003	101
Benchmark	N/A – results to be compared to prior years

The 2006 results indicate an increase over the previous year. Gas rate volatility through the heating season contributed to this increase as well as significant staff turnover in the call centre resulting from a restructuring initiative. Additionally, beginning in March of 2006 the statistics include the results for the combined Terasen gas customers including TGVI and TGW, a 10% increase in the base level of customers as compared to prior years. The 2006 year end results are expected to reflect an increase over the prior year although the number of complaints is not expected to reach the level experienced in 2004.

10. Customer Satisfaction (Number of Prior Period Adjustments)

This service quality indicator is new for the 2004-2007 PBR. This indicator tracks the number of prior period adjustments for Industrial Transportation Service customers. A prior period adjustment is a billing inaccuracy that is identified after a bill has been issued; if this occurs, the bill is adjusted with any necessary corrections. Historical information is only available beginning in 2003. It was agreed during the 2004 – 2007 PBR Settlement, that there is no performance threshold for this SQI but that results would be considered in the context of previous results.

Year	Number of Prior Period Adjustments
2006 (Jan - Aug)	15
2005	14
2004	18
2003	24
Benchmark	N/A – results to be compared to prior years

The 2006 year-to-date prior period adjustments result of 15 is less than the benchmark of 24.

2.1.5 Directional Indicators

Two of the previous SQIs were not effective as measures but they are included as Directional Indicators.

1. Number of Third Party Damages

Terasen Gas continues its efforts in preventing third party damages to the distribution system. There is no direct link between Third Party Damages and housing starts, so "Number of Third Party Damages" is tracked and reported as a Directional Indicator, with no benchmark.

Year	Number of Third Party Damages
2006 (Jan - Aug)	1023 incidents
2005	1457 incidents
2004	1492 incidents
2003	1459 incidents

The 2006 year-to-date number of third party damages at 1,023 incidents is projected by year-end to be slightly higher than the past three years due to the current high levels of construction, particularly major provincial infrastructure projects such as Gateway and the Ravline.

2. Leaks per Kilometre of Distribution Mains

The number of leaks may measure integrity to a certain extent, but in practice, there is an apparent incentive to lengthen the frequency between surveys in order to reduce the number of leaks detected. Each year approximately one-fifth of the Distribution System is surveyed for leaks. The number of leaks found will vary, in the short term, more because of the condition of the portion of the system being surveyed in the given year than it will be affected by the quality of the current maintenance program. This statistic will only become valid over a much longer time horizon; probably 15 to 25 years. Terasen Gas believes it should be detecting as many existing leaks as reasonably possible so the results of this measure may run somewhat contrary to the true objective. This measure will continue to be tracked manually and reported as a Directional Indicator, with no benchmark.

Year	Leaks per Km of Distribution Mains
2006 (Jan - Aug)	0.0016 (58 leaks)
2005	0.0034 (120 leaks)
2004	0.0045 (150 leaks)
2003	0.0040 (134 leaks)

The 2006 year-to-date number of leaks per km of distribution mains of 58 leaks is projected by year-end to be within the range of previous years.

2.1.6 Conclusion

It is Terasen Gas' submission that service quality continues to be maintained in 2006 and, moreover, has been maintained throughout the settlement period.

2.2 Summary of Service Quality Indicators

	Performance Measure	Service Quality Indicator	Benchmark
1	Emergency Response Time	Response Time Dispatched to Site for Emergency Calls	21.1 minutes
2	Speed of Answer - Emergency	Percent of Responses Within 30 Seconds by a Person for Emergency Calls	95.0%
3	Speed of Answer - Non-Emergency	Percent of Responses Within 30 Seconds by a Person for Non-Emergency Calls	75.0%
4	Transmission System Integrity	Transmission System Annual Reportable Incidents	2
5a	Residential & Commercial Customer Billing Activity	Index Based on the Percent of Customer Bills Produced Meeting Accuracy, Timeliness, and Completion	5.0
5b	Industrial Customer Billing Activity	Percent of Industrial Customer Bills Accurate	99.5%
6	Meter Exchange Appointment Activity	Percent of Appointments Met for Meter Exchange	92.2%
7	Industrial Meter Measurement	Industrial Meter Measurement First Report under 10%	90.0%
8	Customer Satisfaction	Independent Customer Satisfaction Survey	N/A – results to be compared to prior years
9	Customer Satisfaction	Number of Customer Complaints to BCUC	N/A – results to be compared to prior years
10	Customer Satisfaction	Number of Prior Period Adjustments	N/A – results to be compared to prior years

2.3 Summary of Directional Indicators

	Directional Measure	Directional Indicator
1	Distribution System Integrity	Number of Third Party Damages
2	Distribution System Integrity	Leaks per Kilometre of Distribution Mains

2006 DEMAND SIDE MANAGEMENT STATUS REPORT

1. INTRODUCTION

Under the terms of the 2004 – 2007 Multi-Year PBR Settlement, Terasen Gas is required to submit an annual Demand Side Management ("DSM") Status Report to the Commission as part of the Annual Review process. This report follows the 2005 Status report in form and content and provides an overview of Terasen Gas' DSM activities in 2006 with details pertaining to the progress of individual DSM programs against forecasted targets and objectives for the year, and details pertaining to other DSM initiatives. As in prior years, Terasen Gas has offered several types of programs most of which are in progress at the time of this writing; therefore, impacts are estimated rather than actual results.

2. GENERAL OVERVIEW OF DSM PROGRAMS AT TERASEN GAS

In 2006, Terasen Gas continued efforts to promote natural gas conservation and efficiency to its customers through a combination of awareness, education and incentive programs. Very few changes were made to program offerings from 2005.

Energy conservation and efficiency is also being promoted by a number of other utilities, agencies and industry members. Terasen Gas continues, whenever feasible, to partner with others to leverage its DSM funds. For example, Terasen Gas was able to enter into a Contribution Agreement with the Ministry of Energy, Mines and Petroleum Resources ("MEMPR" or the "Ministry') in March 2006 for the amount of $2.4 million. This Contribution Agreement, which terminates on March 31, 2007, details the Ministry's contribution to both program and incentive costs for a market survey of gas contractors, for Energy Star furnace/boiler upgrades in residential new construction and retrofits, for a Commercial Boiler program, and for sponsorship of the 2006 BC Energy Forum. The majority of Terasen Gas initiatives to which the Ministry is making a financial contribution support the Government of British Columbia's strategy around "Energy Efficient Buildings: A Plan for BC". More information on this strategy can be found at http://www.em.gov.bc.ca/AlternativeEnergy/EnergyEfficiency/buildings.htm. However, at the time of writing, there is considerable uncertainty as to the nature and extent of federal funding for promoting energy efficiency. If the Government of Canada chooses to scale down investment in promoting energy efficiency, the opportunities to benefit ratepayers by continuing to leverage Terasen Gas' investment with funding partners such as Natural Resources Canada ("NR Can") and Environment Canada, and with the Ministry may be limited.

Another strategy which Terasen Gas and its partners adopted this year was to take a "bundling" approach, where incentives from Terasen Gas and its partners are offered in one "bundle" aimed at a particular market segment. By adopting a bundling approach to offerings and incentives, it is expected customer interest and participation will increase as the perceived total amount of incentives will be higher than stand-alone incentives and the application process will be much simpler and easier as there will be only one application required for the multiple incentives available. The success of this approach will be evaluated in 2007.

As in past years, programs are subjected to economic cost-benefit tests (most notably a standardized Total Resource Cost ("TRC") test) prior to launch. Terasen Gas did not have any programs conclude during the first half of 2006, however several programs are due to conclude by the end of the year and in 2007, and those programs will be evaluated by third parties at the time that they conclude. The planned evaluations will provide insight into opportunities for future improvement and assist in measuring actual natural gas savings against projections. In the case of programs where the projected energy-saving measures adopted by the customer are significant, as would be the case if a furnace or boiler is changed to a high efficiency model, Terasen Gas will utilize analysis of customer billing data to support projected gas savings.

DSM initiatives may also produce benefits for the utility, the customer, and society in general which are not considered part of the TRC test. Of particular interest are the emission reductions which essentially lead to a reduction in Greenhouse Gas ("GHG") emissions and improved local air quality (the latter arising from Criteria Air Contaminant ("CAC") emission reductions). GHG emission reductions from Terasen Gas programs were tracked and information gathered in 2006, however, projected CAC emission reductions are not actively tracked, because at this time, there does not appear to be a valuation and trading mechanism on the horizon for Canada for CAC emissions.

3. EDUCATION AND OUTREACH INITIATIVES

Destination Conservation

Destination Conservation ("DC") is a K-12 school program involving students, teachers and school facilities management staff.

The program is organized by the Pacific Resource Conservation Society, a BC based not-for-profit group, and offered to school districts. It features energy conservation curricula and support materials for participating teachers and technical assistance to school facilities management staff. The DC program includes an energy monitoring component which allows school districts to monitor, analyze and report energy usage information. Utilizing software programs such as 'Utility Manager 4.0 Pro' coupled with operator training, schools are able to report weather-normalized energy savings resulting from implementation of energy efficiency measures. Terasen Gas considers this approach to be a cost-effective means of monitoring program impacts.

Terasen Gas has contributed a portion of the first year operating costs for the program to a number of school districts in prior years. In 2006 school districts in the province experienced considerable uncertainty related to the teachers' contracts, thus non-core initiatives such as DC were pushed to one side, likely leading to lower participation by fewer schools than previously projected. However, Terasen Gas anticipates greater activity with more school districts adopting DC in 2007, and is evaluating a proposal from the Pacific Resource Conservation Society for "DC at Home", which would carry the DC messaging into students' homes.

Commercial Energy Utilization Advisory

This program is being offered to larger Rate 3/23 and Rate 5/25 commercial customers by the Terasen Gas Commercial Energy Services group. The offer includes an initial benchmarking consultation and an onsite assessment of natural gas conservation and efficiency opportunities along with recommendations and estimated savings. To date there have been 48 completed assessments in 2006, and an expected total of 60 by year end. Typically, 25% of the customers who receive the assessment implement the recommended measures and average 600 GJs in annual savings.

Publications

On an ongoing basis, Terasen Gas publishes a number of brochures and pamphlets to encourage residential customers to adopt energy savings measures and practices. These would include such items as our "Hot Tips" booklet, which contains a number of energy saving tips that homeowners can readily perform themselves.

Mass Media Communication

In 2006, Terasen Gas continued with the use of television commercials as a way to promote its energy efficiency programs and to draw attention to the importance of energy efficiency. For Fall 2006, the television campaign will contain program-related DSM "tags" at the end of the commercials. Further, Terasen Gas will be launching a series of radio "tags" as a means of promoting the Energy Star Heating Upgrade program, which should further reinforce the importance to consumers of energy efficiency measures to assist them in managing energy costs.

Community Energy Planning Participation

Terasen Gas continues to be an active participant in community-based conservation initiatives (i.e. the Community Energy Association) and collaborates with the provincial and federal governments to review and to implement energy efficiency standards. Terasen Gas is an active supporter of British Columbia's "Community Action on Energy Efficiency" strategy (http://www.em.gov.bc.ca/AlternativeEnergy/EnergyEfficiency/default.htm).

2006 BC Energy Forum

Terasen Gas in cooperation with BC Hydro, MEMPR and NR Can organized the 2006 BC Energy Forum, held at the Wosk Centre for Dialogue in Vancouver on January 24 and 25. The Forum brought together a number of experts in the fields of energy efficiency, alternative energy, transportation, as well as government and regulatory experts for two days of presentations and panel discussions. The purpose of the forum was to increase understanding and collaboration related to energy issues in British Columbia; it was well-received.

Trade Show Activity

Terasen Gas will be participating in the 2006 Vancouver Home and Interior Design Show, being held October 12 to 15 at BC Place Stadium in Vancouver. A major focus of our activity at this trade show will be promoting energy efficiency in general, focussed on Energy Star and specifically on our Residential Heating Upgrade incentive program for winter 2006.

Other Activities

Terasen Gas engages in a number of demand side management related activities designed to enhance energy efficiency-related outcomes in British Columbia. Some of them are described below:

- Terasen Gas participated and continues to participate on the Steering Committee for BC Hydro's Conservation Potential Review and on BC Hydro's Electricity Conservation and Efficiency Advisory Committee.
- Terasen Gas sponsored the Douglas College program called "Building Operator Training" which is designed to address ongoing maintenance and upgrades to commercial building operations by training facilities staff in efficiency techniques.
- Terasen Gas sponsored the Building Owners and Managers Association's development of an on-line training course related to energy efficiency.
- Terasen Gas supported the development of a consumer education campaign by the Hearth, Patio and Barbeque Association designed to increase consumer understanding of fireplace efficiencies.
- Terasen Gas supported Code Green Canada, a reality television show in which participants competed in making energy efficient upgrades to their homes.
- Terasen Gas participated in Natural Resources Canada's annual Energy Star meetings in Toronto, where Terasen Gas received an Energy Efficiency Recognition Award.

4. 2006 INCENTIVE PROGRAM DESCRIPTIONS

Energy Star Heating System Upgrade

Originally launched on September 1, 2005, and scheduled to expire December 31, 2006, the 2006 program represents a continuation of the original program. As in previous years, this year's Residential Heating System Upgrade program once again offers financial incentives to residential customers to replace older furnaces and boilers with ENERGY STAR qualified high efficiency natural gas models. The "Winter 2006" version of the program will be officially launched October 1, 2006, and has been extended from an original termination date of December 31, 2006 to March 31, 2007. This extension was implemented to coincide with the termination of Terasen Gas' agreement with the MEMPR. Other partners on this program include NR Can (to March 31, 2006), MEMPR, BC Hydro, FortisBC, and 15 participating brands (for Winter 2006). These partners are contributing funds to promotional costs and customer incentives.

Under this program, residential customers are offered a $250 utility bill credit towards the purchase of an ENERGY STAR qualified high efficiency natural gas furnace or boiler of which Terasen Gas is contributing $100, MEMPR is contributing $150, and BC Hydro and FortisBC are jointly funding an additional $100 incentive with MEMPR if the selected furnace has a variable speed motor.

Additional supplier-funded incentives ranging from $150 to $1,000 in value toward the purchase of 15 brands of ENERGY STAR qualified furnaces and boilers are being promoted by Terasen Gas as part of this program. Most of the major suppliers of high efficiency heating systems in BC are participating—contributing $2,000 towards the direct promotional costs of the campaign and, in some cases, conducting their own independent promotional campaigns. The manufacturers are responsible for administering their own coupons and, with the coupons only, valid for redemption between October 1, 2006 and January 31, 2007.

The program design for the 2006/7 program estimates the average annual natural gas savings at 13.8 GJ per participant and 3,300 participants overall. This results in a cumulative GJ savings of 45,540 GJ/annum, a cumulative CO2e savings of 2,308 tonnes, and a TRC of 1.82.

<u>New Construction Energy Star Heating System/Power Smart New Home Program</u>

The Residential New Construction Heating program originally launched January 1, 2005, has been bundled into the PowerSmart New Home Program, and extended through to March 31, 2007. The PowerSmart New Home Program was launched in July 2006, bundling the Terasen Gas incentives, BC Hydro incentives, and MEMPR incentives to offer builders and developers up to $3,000 for the installation of Energy Star equipment and a new home that achieves a rating of 80 on the Energuide for New Homes scale. BC Hydro and Terasen Gas are sharing the administration of the program with program inquiries handled by Terasen Gas staff while incentive processing is handled by BC Hydro Power Smart staff. For a single family dwelling (“SFD”), the customer incentives are as follows:

Incentive Description	Incentive Amount
Energy Star Windows Program	$1/square foot – generally approx. $500 in SFD
Energy Star Gas Heating	$500
Basic Appliance Rebate – Energy Star Fridge, Dishwasher, Vent Fan, 40% CFL lighting OR Full Appliance Rebate – As above plus Energy Star Clothes Washer, Natural Gas Range and Natural Gas Dryer (must have Gas Domestic Hot Water)	$150 or $600
Energuide for New Homes Rating of 77 OR Energuide for New Homes Rating of 80 with Electric Heat OR Energuide for New Homes Rating of 80 with Gas Heat	$200 OR $900 OR $1,400

Should a builder wish to select only the incentive for Energy Star Natural Gas heating, on a stand-alone basis, the builder may do so. The same is true of the appliance bundle, and the windows incentive. There are also incentives available for townhomes and high-rise condominiums, although the incentive amounts are lower because they typically do not have as much window space, lowering the incentive contribution from BC Hydro for Energy Star windows. In addition, many condominiums also do not have individual space heating appliances, eliminating the incentive for Energy Star Natural Gas Heating. The PowerSmart New Home program is Terasen Gas' first experience with bundling its incentives with partners' incentives, with the first opportunity to evaluate the effectiveness of this approach in late spring 2007.

To date there are about 176 applications for the Residential New Construction Program, and about 450 signed up for Power Smart New Home Program. The Residential New Construction program is tracking to expectations with a program goal for 2006 of 750 participants and most of those participants are expected to apply once the prime construction season is complete.

For the Residential New Construction Program, the program design for the 2006/7 program estimates the average annual natural gas savings at 9.1 GJ per participant and 750 participants overall. This results in a cumulative GJ savings of 6,825 GJ/annum, a cumulative CO_2e savings of 346 tonnes/annum, and a TRC of 1.45.

For the Power Smart New Home Program, the program design for the 2006/7 program estimates the average annual natural gas savings at 30 GJ per participant and 300 participants overall. This results in a cumulative GJ savings of 9,000 GJ/annum, a cumulative CO2e savings of 456 tonnes/annum, and a TRC of 1.49.

Efficient Boiler Program

This program was modified from that which was offered in previous years. This program is jointly funded by Terasen Gas, NR Can and MEMPR. Due to run-ups in the commodity price of metals, purchase prices for boilers have significantly increased. The incentives offered under the Efficient Boiler Program were correspondingly increased, with the result that the market responded strongly to the program. The program consists of a base incentive plus a variable incentive calculated on boiler capacity. Incentive updates were as follows:

- Near-condensing boilers: $4,000 plus $3.00/MBH (an increase of $1/MBH).
- Condensing boilers: $6,000 plus $9.00/MBH (a $2,000 increase in the fixed incentive plus an increase of $3/MBH).

For condensing boilers, the increase in the fixed incentive is designed to address the additional cost of venting high efficiency boilers in new construction applications; in both cases, the incentives contribute about 50% of the incremental cost of an efficient boiler. At the time of writing (September 2006), this program which was originally designed to run to the end of 2006, was fully subscribed.

This program has been highly successful, such that NR Can is contemplating launching a national version of the program based on Terasen Gas' design.

The program design for the 2006 Efficient Boiler program estimates the average annual natural gas savings at 850 GJ per participant and 98 participants overall. This results in a cumulative GJ savings of 83,300 GJ/annum, a cumulative CO2e savings of 4,222 tonnes/annum, and a TRC of 2.43.

5. SUMMARY OF 2006 RESULTS

Total Resource Cost Test and DSM Incentive Status

The TRC test is a measure of the net benefits of a utility's DSM programs. Terasen Gas calculates overall TRC impact on a 'portfolio' basis, that is, by examining the impact of the combined group of programs for the year.

For the 2006 portfolio (as identified in the table below), the TRC net benefit for specific programs is forecasted to be approximately $6.5 million with a combined TRC ratio of 2.0. The numbers presented in the table below reflect only total projected incentive applications received in calendar year 2006 with some of the programs running into 2007. The TRC net benefit from programs, less the non-program specific DSM costs incurred for salaries, administration, overhead, research, and non-program related education, outreach and promotion is forecasted to be approximately $5.7 million.

Program Name	# of Participants	GJ saved per Participant	GJ saved per year	CO2e saved (tonnes) per year	TRC result	TRC Net Benefit
Energy Star Heating Upgrade	3300	13.8	45,540	2,308	1.82	$ 1,141,525
New Construction Heating Program	750	9.1	6,825	346	1.45	$ 162,158
Power Smart New Home Program	300	30	9,000	456	1.49	$ 604,529
Efficient Boiler Program	98	850	83,300	4,222	2.43	$ 4,101,737
Utilization Advisory	60 with 25% implementing	600	9,000	456	2.4	$ 366,204
Destination Conservation	18	113	2,034	103	2.21	$ 76,298
Totals			**155,699**	**7,892**	**1.97**	**$ 6,452,451**

Greenhouse Gas Reduction

In its demand side management incentive offers, Terasen Gas informs participating customers of its intent to record resulting emission reductions as part of the company's GHG Management Program. The net GHG savings resulting from Terasen Gas energy efficiency incentive programs is estimated to be 7,892 tonnes per year.

DSM Incentive Mechanism

To qualify for the DSM Incentive, a threshold of 75% of the established energy savings target of 177,425 GJs must be achieved, entitling Terasen Gas to an incentive of 3% of the TRC net benefits. Where the energy savings meet or exceed the threshold target of 177,425 GJs, the incentive percentage increases to 5% of the TRC net benefits. Given the projected energy savings and net TRC benefits for 2006, Terasen Gas would be eligible for a DSM incentive of approximately $170,000 (i.e. 3% of $5.7 million).

As the projections provided are estimates only at this time, Terasen Gas will be confirming the actual 2006 customer participation rates and energy savings in 2007 prior to submitting a final incentive payment request.

6. SUMMARY OF COSTS

Program and administration costs as well as customer incentive costs are forecasted to remain within the allowed levels in 2006.

	Allowed ($000)	Projected ($000)
Administration, marketing and research	1,624	1,600
Customer Incentives	1,500	1,500

7. PROPOSED 2007 INITIATIVES

In the absence of increased funding from that approved for DSM to support new programs, Terasen Gas will continue with its “core” initiatives in 2007; the Residential New Construction and Energy Star Heating Upgrades and the Commercial Efficient Boiler Program as these programs have been successful with residential and commercial customers. In addition, Terasen Gas intends to investigate the feasibility of expanding the Energy Star appliance program. Further, Terasen Gas is currently undertaking a feasibility study around offering a smaller efficient boiler program aimed at commercial customers served under Rate Schedules 2 and 3/23, as well as exploring areas of interest in the lodging and food processing sectors. It should be noted that effective January 1, 2008, MEMPR will be regulating Energy Star furnaces and boilers for residential new construction, so Terasen Gas intends to end its incentive program for Energy Star furnaces and boilers in single family new construction at that time.

8. RESEARCH INITIATIVES

Multi-Utility Studies

Terasen Gas continues to participate in a number of multi-utility research initiatives led primarily by the Canadian Gas Association. An example of this is Terasen Gas' financial participation in Canadian Gas Association's "DSM Protocol Study". Terasen Gas is also participating with Enbridge Gas in a study of domestic hot water appliances.

Gas Contractors Survey

Terasen Gas engaged Synovate to conduct a survey of BC Safety Authority-registered Gas Contractors to collect information about the type of work gas contractors do, and to determine how contractors prefer to receive training. The general result from the survey was that Gas Contractors prefer ½ day or breakfast seminars. This approach was tested at a training meeting for gas contractors in Kelowna in 2006, and it was positively received by the gas contractors who attended.

Conservation Potential Review

In 2006, Terasen Gas received the completed Conservation Potential Review ("CPR") conducted by Marbek Resource Consultants. Marbek was also the lead consultant on the 2002 BC Hydro CPR and was, therefore, able to leverage developed models, market profiles, data classifications and archetypes.

Key Deliverables of the CPR

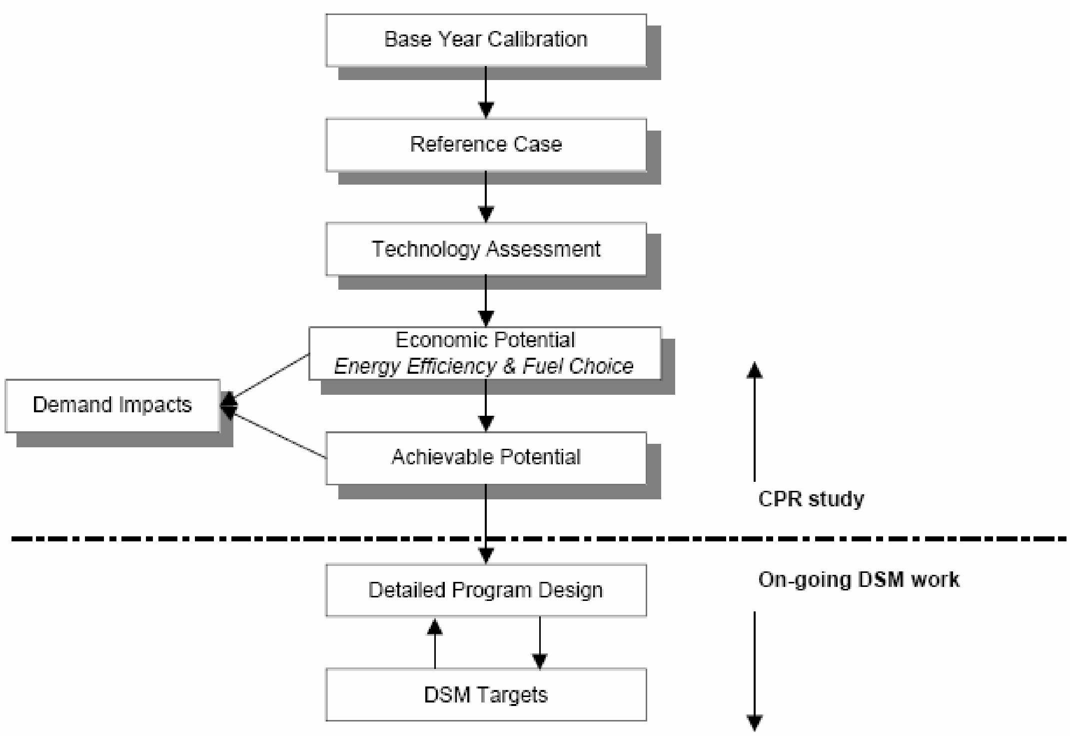
The CPR focuses on economic screening of natural gas and fuel-independent technologies as well as the combined utility economic analysis of *fuel substitution* (from electric to natural gas). It examines resource potential for efficiency at specified milestones, by specific market and end-use, over the 2005 - 2015 forecast period.

The deliverables for each of the outcomes are defined in the following table:

Outcome	Content
Analysis of natural gas DSM measures by geographical area	• Stock definition and update of technologies • technology profiles • economic potential • Sensitivity analysis (uncertain fuel costs) • GHG Impact
Analysis of fuel substitution economics by geographical area	• base year calibration • reference case development • impact on peak demand for gas and electric • consider costs of the marginal source of electrical supply based on geographical area* • GHG Impacts
DSM Achievable potential	• A set of multi-participant workshops to consider delivery, timing and funding constraints

Overview of CPR Process

The flow chart below describes the work process undertaken by Marbek in arriving at the conclusions found in the CPR.



Conclusions of the CPR

The high-level results of the CPR are presented below. Cumulative potential GJ amounts in the table below are comprised of a portfolio of potential measures for each sector and geographic region. A more detailed discussion follows of current thinking in British Columbia around energy efficiency, the results of the CPR and the potential for a broader DSM initiative at Terasen Gas.

By 2015/2016, GJ per year	TGVI	Lower Mainland	Interior	Total
Residential EE	-369,000	-5,298,000	-1,847,000	-7,514,000
Commercial EE	-385,000	-1,396,000	-431,000	-2,212,000
Industrial EE	-32,430	-933,064	-924,210	-1,889,704
Subtotal	-786,430	-7,627,064	-3,202,210	-11,615,704
Residential Fuel Sub				1,453,000
Potential Annual Impact				-10,162,704

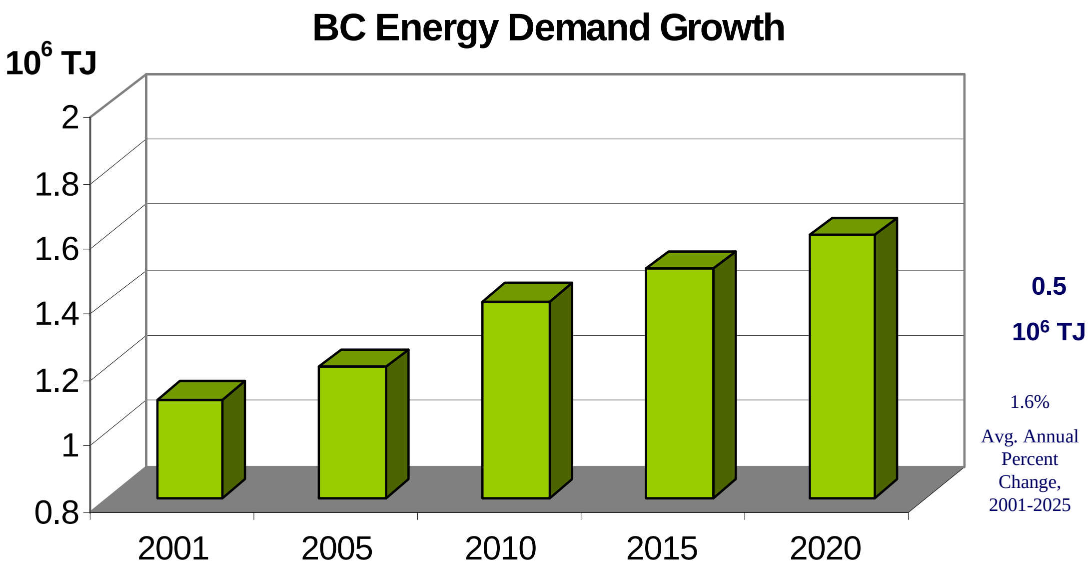
The CPR states that in order to achieve these results, Terasen Gas and its partners would need to increase investments in Terasen Gas demand side management programs by 3 to 5 times the current amount invested.

9. CONSERVATION AND ENERGY EFFICIENCY AT TERASEN GAS: TOWARDS SUSTAINABILITY

The Benefits of Conservation and Energy Efficiency

Terasen Gas believes natural gas provides a safe, reliable, secure, affordable and efficient energy choice to meet the growing needs of businesses and communities while enabling the pursuit of sustainability over the long run. Integral to achieving the sustainability goal in energy choice is the underlying notion of “the right fuel in the right place at the right time”. It makes sense to use natural gas with energy efficient appliances for space and hot water heating, helping to preserve heritage electric capacity for uses where it makes the most sense for things like powering computers, lighting and television.

This is becoming more importantly so, as demand for energy in the Province continues to increase. The following graph outlines the projected energy demand for British Columbia over the next two decades, with demand projected to grow to 1.6 exajoule (1 exajoule = 1,000,000 terajoule) by 2020.



Source: Strategic Imperative for BC's Energy Future – BC Progress Board report

New energy supplies are required to meet growing demand and support economic growth. Conservation and energy efficiency will help meet some of this demand, contributing to providing a sustainable energy solution to meet the energy challenges British Columbians face.

In addition to providing a sustainable energy solution, energy conservation and efficiency initiatives help Terasen Gas customers to lower their annual household energy costs. For example, from 2001 to 2005, first year annual gigajoule ("GJ") savings realized are estimated to have averaged 160,000 GJ per year or cumulatively 800,000 GJ over the five years. At today's residential variable rate of approximately $11.00 per GJ including commodity and delivery, those customers that have participated in energy efficiency opportunities will be saving close to $9 million per year in total.

For Terasen Gas, not only do promoting conservation and energy efficiency initiatives benefit its customers and help contribute to meeting the Province's energy challenges, it helps also to maintain the company's competitive position relative to other energy providers. With the escalation in natural gas prices the last number of years, the significant commodity price advantage that natural gas has enjoyed over other fuels historically, particularly electricity has eroded materially. This fact coupled with the high upfront capital costs of installing natural gas service is leading customers, builders and developers to choose other energy sources than natural gas for space and hot water heating.

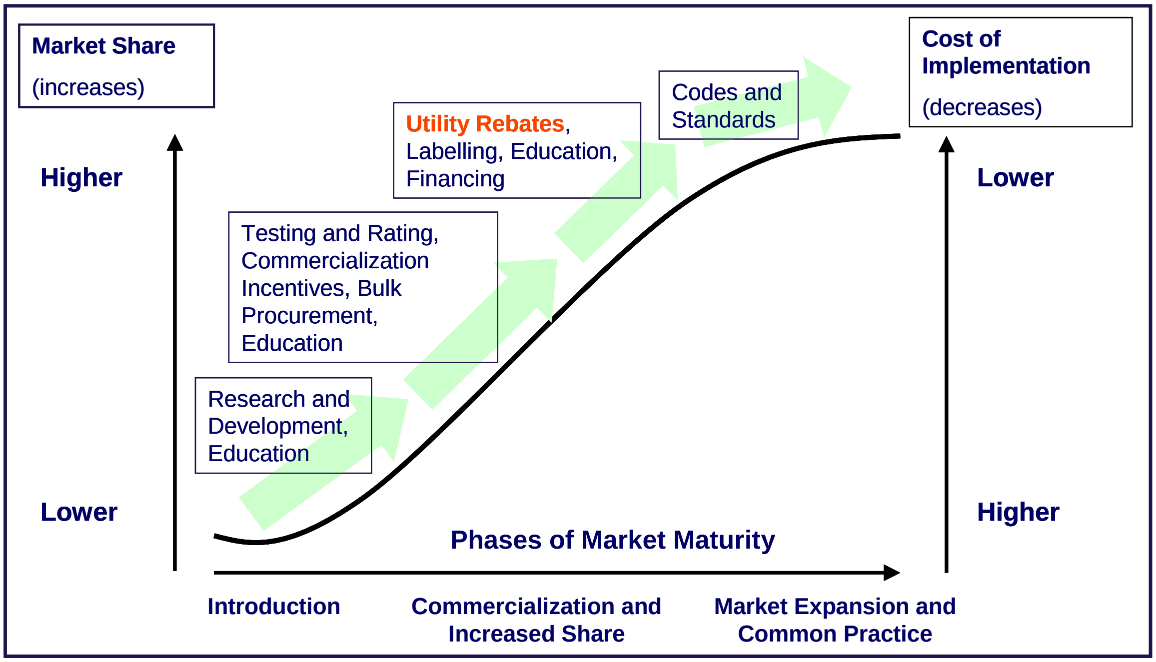
By encouraging use of efficient natural gas appliances through education, awareness and incentive programs, Terasen Gas is able to assist its customers to use natural gas more efficiently, making it that more economically attractive. For example residential customers who have a high efficiency natural gas furnace today pay 30% less for space heating that they would if they used electric space heating. In the long run, providing an efficient, competitively priced energy choice will help Terasen Gas retain and grow its customer base, and contribute to the optimal use and development of the gas distribution system.

Terasen Gas' Approach to Conservation and Energy Efficiency

Terasen Gas' focus and strategy has been to promote natural gas conservation and efficiency to its residential and commercial customers through a combination of awareness, education and incentive programs, incorporating a portfolio approach to DSM planning. Fundamental to maximizing the effectiveness of DSM programs for customers has been Terasen Gas' success in working with third parties such as BC Hydro, NR Can and the MEMPR in developing and implementing energy efficiency programs, with the third parties contributing funds towards the delivery of the programs and incentives paid to customers.

Terasen Gas firmly believes its plays an important role in encouraging conservation and energy efficiency, creating consumer awareness and contributing expertise and resources to encourage adoption of efficient gas technologies. The diagram below outlines the traditional process used to encourage adoption of energy efficiency measures, starting with research and development activities at the early stages, where acceptance of a new efficient technology is low and the costs of implementation are high due to low commercialization of the technology. By encouraging understanding and use of the new efficient technology through education, awareness and financial incentives, the market for the new efficient technology will “mature” to the point where codes and standards can be introduced to make it a mandatory requirement.

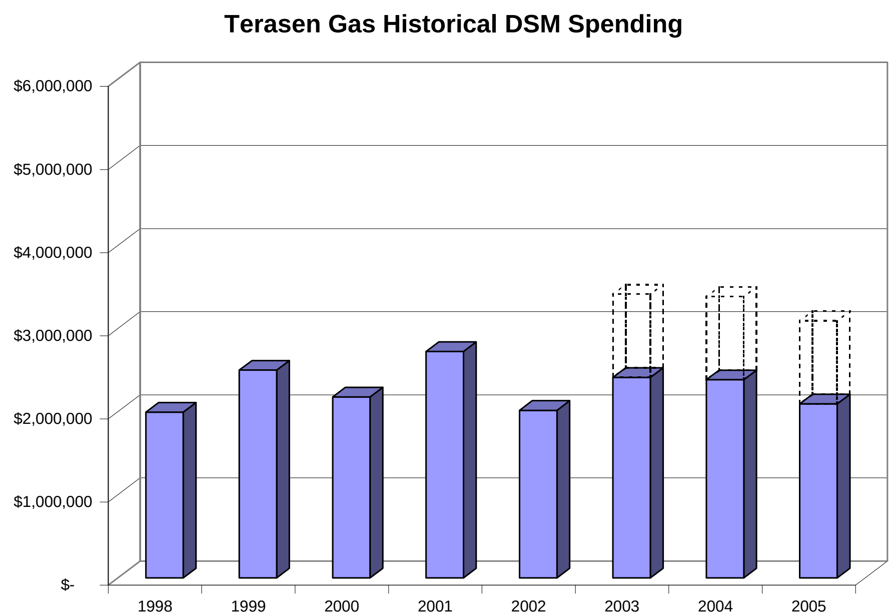
Energy Market Transformation – The Steps Along the Way



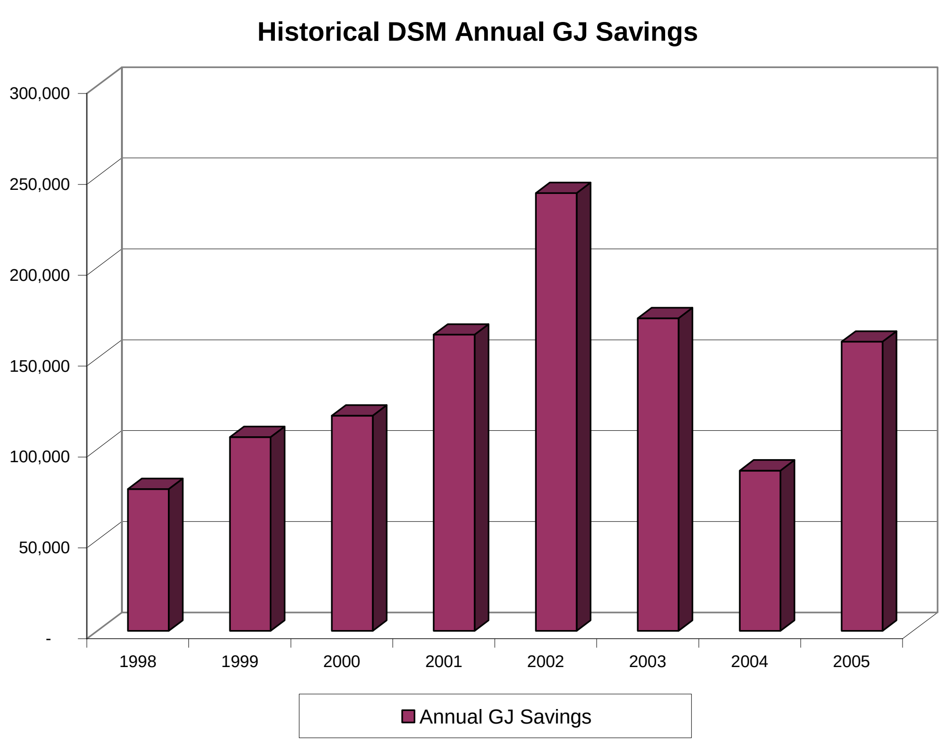
Source: BC Ministry of Energy and Mines

History of Terasen Gas DSM Activities

Terasen Gas' current approved funding of $3.1 million per year; $1.6 million in operating and maintenance expenses and $1.5 million in customer incentives was established as part of the Commission's decision on the 1998 – 2002 Performance Based Rate Plan and Revenue Requirements Application. Since then, no changes have been made to the approved funding levels. The chart following illustrates the actual levels of DSM spending for Terasen Gas from 1998 to 2005. Actual expenditures from 1998 to 2005 averaged about $2.5 million per year, varying from year to year depending on the types of programs launched and the actual customer sign-up rates. Not included in the total expenditures provided are financial contributions from third parties (i.e. NR Can) which are used primarily to increase the financial incentive to a customer for participating in an energy efficiency program. During the last several years, funding partners have contributed over $3 million towards Terasen Gas' energy efficiency programs (refer to graph and outlined sections of bar chart).



The chart below outlines the estimated annual GJ savings associated with the programs launched for each of the years presented.



Annual gas savings for customers have ranged between 80,000 to 240,000 GJs per year from 1998 to 2005 with an average of 125,000 GJs per year over the period. Annual energy savings achieved have been higher on average from 2001 onwards, the time when natural gas prices spiked, triggered by the energy crisis in California. The year 2002 has been the highest in annual energy savings achieved during the last number of years, highlighted with significant response from residential customers to the Furnace Tune-up program offering. First offered by Terasen Gas in the summer of 2001, the heating system tune-up was re-launched in mid 2002 to include both furnaces and boilers. Customer reaction was very positive in 2001, with some 27,000 customers participating. Similar to the 2001 program, the 2002 tune-up offer was formulated to encourage customers to engage a contractor registered with the provincial Gas Safety Program to perform a series of furnace or boiler maintenance operations, performance checks and appliance adjustments. The offer included a $25 utility bill credit for participants. Approximately 45,000 customers participated in 2002, bringing in total overall program participation over the two years to more than 70,000 customers.

The Changing Marketplace for Conservation and Energy Efficiency

Much has changed since 1998 when Terasen Gas' existing DSM funding level was determined. Energy use and cost for oil, gasoline, electricity and natural gas are very much on consumers' minds. Oil prices have risen dramatically in the last couple years and have stayed at the new high levels between $55 to $60 per barrel of oil. Gasoline prices, which significantly impact our daily lives, have jumped from the sixty cent litre of three years ago to just under a $1 per litre today. Electric rates are starting to trend upwards, with rates increasing 10% in the last several years. The natural gas commodity charge Terasen Gas charges has increased from about $2.50 per GJ in 1998 to today's rate of approximately $8.00 per GJ, an increase of approximately 300%. From a consumer's perspective, the economic attractiveness of undertaking energy efficiency improvements is a more pertinent issue today than it was eight years ago.

Use of energy and how best to supply the growing energy needs are also important issues often discussed these days as British Columbians face the challenging task of finding sustainable energy solutions that balance the economic, social and environmental needs of communities and stakeholders. Energy efficiency and conservation are now being seen by stakeholders as a fundamental element of a sustainable energy framework. Evidence of this increased importance is provided in two recent documents published by the MEMPR and the BC Progress Board.

In September 2005, the MEMPR published its Energy Efficient Buildings: A Plan for BC. The plan outlines a number of energy efficiency actions that deliver social, environmental and economic benefits throughout BC by conserving energy and improving the energy efficiency of homes and buildings. Specific to the use of natural gas are targeted annual gas savings by 2020 in the new construction sector of $99 million for new detached single family and row houses and $42 million in new commercial, institutional and industrial buildings.

In November 2005, the BC Progress Board, an independent panel of 18 senior business and academic leaders in British Columbia, issued a report outlining the energy opportunities in British Columbia along with specific actions that should be taken. One of these actions is Strategic Imperative #5 – Conservation and Energy Efficiency are Essential. The report states "*We must reduce energy consumption and emissions. Energy conservation, energy efficiency, and alternative energy sources are the only way to achieve this imperative*."

Comparison of DSM Funding for Natural Gas Utilities in Canada

As a percentage of total utility revenue, Terasen Gas' existing approved DSM funding of $3.1 million per year ranks the lowest when compared to the other major gas utilities DSM funding in Canada. The following table lists the gas utilities in Canada, their DSM funding and their ranking as a percentage of total utility revenue.

2004 DSM expenditures, by company, ranked in order of DSM expenditure as a proportion of revenue

LDC	Number of customers	DSM expenditure ($ millions)	Total utility revenue ($ millions)	% of total utility revenue	Utility revenue less cost of gas ($ millions)	% of utility revenue less cost of gas
Enbridge	1,671,442	$ 13.09	$ 2,408	0.54%	$ 987	1.33%
Gaz Metro	158,527	$ 5.55	$ 1,783	0.31%	$ 555	1.00%
Atco	906,550	$ 4.30	$ 1,550	0.28%	$ 407	1.06%
Union	1,223,584	$ 4.60	$ 1,791	0.26%	$ 885	0.52%
SaskEnergy	326,985	$ 0.73	$ 317	0.23%	$ 167	0.43%
Terasen	885,200	$ 2.20	$ 1,494	0.15%	$ 609	0.36%

Source: DSM Best Practices, Indeco 2005

Terasen Gas ranks last, at the bottom of the list with actual spending recorded in 2004 of $2.2 million, representing only 0.15% of total utility revenue of $1.5 billion. Gas utilities such as Atco Gas in Alberta and Enbridge Gas and Union Gas in Ontario that are similar in size to Terasen Gas in terms of the total number of customers and also the percentage of customers that are residential (i.e. ~90%) spend significantly more each year of their total utility revenues on DSM programs. In 2004, Enbridge Gas spent over $13 million on DSM programs or 0.54% of total revenues. Atco Gas spent over $4 million or 0.28% of total utility revenue whereas Union Gas spent $4.6 million or 0.26% of total utility revenue.

DSM funding for other gas utilities also continue to increase. As part of the Ontario Energy Board's recent decision dated August 25, 2006, on demand side management activities for natural gas utilities, Enbridge Gas' approved DSM funding was increased to $22 million for 2007 with annual increases thereafter of 5% per year resulting in an approved DSM budget for 2009 of $24.3 million. Union Gas' DSM funding for 2007 was approved for $17 million with annual increases of 10% per year for 2008 and 2009, leading to a DSM budget for 2009 of $20.6 million.

As mentioned earlier, Terasen Gas' DSM funding of $3.1 million was set back in 1998, as part of a multi-year performance based rate making agreement. At that time, the approved DSM funding represented approximately 0.4% of total utility revenues of $764 million. Since 1998, no change to DSM funding has been approved with the budget remaining at $3.1 million while the company's total utility revenue has topped approximately $1.5 billion, an increase of 100% largely due to higher commodity prices.

Higher commodity prices provide a greater incentive and benefit for customers to undertake energy efficiency improvements. Terasen Gas' approved DSM funding however has not kept pace with the growing demand for energy efficiency in the marketplace, unlike other utilities such as Enbridge Gas and Union Gas who will be increasing their DSM funding in the coming years, availing their customers the opportunity to manage their household energy costs while at the same time providing a solution to the province of Ontario's energy challenges.

The CPR study has identified a number of opportunities and sectors in which energy efficiency savings can be realized. With the existing approved DSM funding, Terasen Gas will be exploring and evaluating these opportunities in the next year or so with some more detailed research and/or potential pilot programs. However, additional funding will be required in the future to realize the available energy efficiency opportunities identified. Terasen Gas is planning to seek an increase in DSM funding in the future, but in light of the current PBR Settlement Agreement is not seeking such an increase at this time. A future DSM funding request would likely be in the range of at least double the current level of funding.

Following is a more detailed discussion of the opportunities Terasen Gas will be investigating and pursuing in the coming months.

Some Selected Opportunities identified by the Conservation Potential Review Study

Residential - High Efficiency Furnaces and Boilers

MEMPR is going to be regulating high-efficiency furnaces and boilers in new construction effective January 1, 2008, but have indicated that for now, they do not plan to regulate efficiency into the home heating retrofit market. This leaves an ongoing opportunity for high-efficiency home heating appliances to be integrated into existing homes. The CPR identified that participation rates of 58% efficient furnaces in existing single family/duplex homes could be achieved by 2015/2016. Terasen Gas has a track record of success with furnace and boiler upgrade programs, so this is expected to continue to be a core DSM activity.

Residential – Efficient Appliances

This is essentially a domestic hot water efficiency initiative that would incent Energy Star clothes washers and dishwashers in both new construction and retrofits. Terasen Gas is testing an appliance initiative in the PowerSmart New Home Program, co-funded by BC Hydro and MEMPR as a fuel substitution measure from the electricity standpoint, providing a $600 incentive to the customer for an Energy Star fridge, dishwasher, vent fan, and clothes washer and natural gas range and dryer.

Residential – Efficient Fireplaces

MEMPR is introducing legislation effective January 1, 2007, compelling fireplace manufacturers to label fireplaces with efficiency ratings. Terasen Gas will be supporting this legislation by working with the fireplace industry association on a public information campaign related to fireplace heating value and efficiency to coincide with the MEMPR labelling regulation. There is an opportunity for Terasen Gas to provide a stepped incentive to customers that purchase a more efficient fireplace, especially in electrically heated homes, that could potentially install a fireplace which has heating value (as opposed to one that is purely decorative). The CPR identified that participation rates of 30% efficient fireplaces could be achieved by 2015/2016, and also felt that this area had risk associated with the penetration of purely decorative electric fireplaces into the new construction market. Educating consumers about the potential for a fireplace to provide heat while consuming energy, rather than just being a decorative feature, could, in and of itself, prove to be an efficiency measure.

Commercial – Ultra High Efficiency New Construction

The focus of this measure is the application of an integrated design process to the construction of new commercial and institutional buildings, with a goal of designing to 60% savings over the Model National Energy Code for Buildings ("MNECB") for large buildings, and 30% savings over the MNECB for medium and smaller buildings. Interestingly, the incremental costs for an ultra-efficient building (at 60% below MNECB) are lower than the incremental costs for a building at 30% below MNECB, because of the equipment downsizing opportunities that are present with very high performance designs. Programs to incent integrated design in commercial buildings would also have spill over into the high-rise multifamily sector, and Terasen Gas would look to establish an incentive program aimed specifically at the multi-family sector as well as at commercial buildings. Where possible, Terasen Gas would leverage its investment in integrated design with partner programs, such as BC Hydro's High Performance Building program. Training and support for building operators, to ensure that high performance buildings are being maintained and are operating as they were designed, is an integral part of achieving the energy savings goals of efficient buildings. Terasen Gas has already significantly invested in two training initiatives: the Douglas College program and the Building Owners and Managers Association on-line training course, initial important steps towards making an efficient new commercial construction program reality.

Commercial – Improved Boilers in both New Buildings and Retrofits

As mentioned earlier, Terasen Gas' Efficient Boiler Program for large boilers (300,000 BTU/hr and up) has been very successful. The vast majority of the uptake to-date though has been for retrofits. The CPR study identified that approximately 80 to 90 per cent of the new construction market could be encouraged to adopt near-condensing equipment by 2015/2016, once some of the other barriers had been overcome. The CPR suggests that market participation would be highest in the institutional and commercial segments assuming the issue of long-term owner-occupancy is addressed adequately. The CPR study as indicates that a design standard for low temperature design, and operator training were also needed as complementary elements of a successful program.

Terasen Gas is currently investigating the feasibility of launching a similar program for smaller commercial boilers.

Commercial – Small Commercial

Terasen Gas has over 70,000 commercial customers served under Rate Schedule 2, representing a broad and diverse group of businesses. Any efficiency programs targeted to these small commercial customers would have to take this into consideration in designing a program that has broad appeal. Examples of some potential efficiency measures are pre-rinse spray valves for the food preparation sub-sector, efficient clothes washers and dryers for the laundry/dry-cleaning sub-sector, and energy efficient food preparation equipment for the restaurant sub-sector.

Fuel substitution

Fuel choice measures continue to be of great interest to Terasen Gas. Terasen Gas plans to work closely with MEMPR and with BC Hydro to examine ways to encourage and incent British Columbians, including the development community, to use the right fuel for the right place at the right time.

REPORT ON THE ESTABLISHMENT OF INCENTIVE MECHANISM FOR REDUCING UNCONTROLLABLE / PARTIALLY CONTROLLABLE EXPENSES FOR THE YEAR ENDING DECEMBER 31, 2006

PROPERY TAX

The 2004 – 2007 Multi-Year PBR Settlement addresses the issue of establishing incentive mechanisms for Terasen Gas for reducing uncontrollable or partially controllable costs.

The Negotiated Settlement, Appendix A to BCUC Order No. G-51-03, indicates that the Company is to have a positive incentive around provincial and municipal government taxes, fees and expenses and that a specific mechanism was agreed to regarding property taxes.

For purposes of determining the incentive, property taxes are divided between the 1% In-Lieu taxes and all other categories of property taxes. The other property taxes include General, School, First Nations, and other taxes, and will herein be referred to as Other Property Taxes.

With respect to the 1% In-Lieu taxes, the Company is entitled to keep 10% of the savings related to achieving a reduced rate for the tax or a changed structure to the tax which lowers the amount payable.

For the Other Property Taxes, a modified version of the formula-based approach applicable to O&M expenses and net gas plant in service will be applied. The 2005 actual amount forms the base to which 2006 customer growth, inflation, and inflation offset factors will be applied to determine the target for 2006. The Company is entitled to 10% of the amount by which its actual taxes are lower than the target.

The 2006 threshold for Other Property Taxes is:

$$\$27,166,000 \times (1+ 1.53\%) \times (1 + 2.20\% - 1.45\%) = \$27,787,000$$

The 2006 Other Property Taxes total is projected to be $27,964,000, which is higher than the 2006 threshold of $27,787,000 (Table A). Since the projected 2006 property taxes are higher than the target, the Company is not entitled to an incentive based upon the 2006 results. However, it is important to note that had Terasen Gas not realized the property tax savings due to its mitigation efforts, the 2006 actual property taxes would have been higher by $299,000 (Table B).

Table A

	2005 Actual	Change	2006
Average Number of Customers	791,593	12,093	803,686
Percentage Growth in Average Customers		1.53%	
Annual Inflation Rate - CPI		2.20%	
Adjustment Factor		1.45%	
Other Property Tax ($000)			
Formula based			$ 27,787
Actual/Projected	27,166		27,964
Difference			($177)

The table below summarizes the total property tax savings realized to-date following the Terasen Gas property tax mitigation plan:

Table B

Item No	Particulars	Actual in 2005	Expected in 2006	Total
1	Distribution Pipeline Update Factor Error	$ -	$ 87,000	$ 87,000
2	Tower Appeal	61,600		61,600
3	Office Appeals (Note 1)		192,200	192,200
4	Other Appeals		19,800	19,800
		$ 61,600	$ 299,000	$ 360,600

Notes
1 Includes $52,900 refund received from settlement of Prior Year appeals in 2006

If Terasen Gas is successful with current mitigation efforts, future property tax savings could reach $539,800 (see discussion on Mitigation Activities in Progress on Page 3 of this Tab).

Background Details behind Property Tax Cost Mitigation Plans

The 2006 property tax mitigation plans were based on preemptive strategies by Terasen Gas with the goal of minimizing property taxes and cost pressures to customers. The savings summarized below are based on actual performance or are based on current ongoing mitigation activities. Unrealized future savings relate to issues that are before the Property Assessment Appeal Board.

Mitigation Activities during 2006:

1. **Distribution Pipeline Update Factor Error** – Terasen Gas discovered an error in the update (or inflation) rates applied by BC Assessment in 2005. An agreement to correct the error in the 2006 taxation year, ensuring the overall assessment over the two years would be as originally agreed upon. This affected mainly Lower Mainland folios. It is estimated that tax savings amounted to $87,000.

2. **Office Appeal** – An appeal was undertaken in 2004 and 2005 on all Terasen Gas offices. In 2006 it was discovered that the classification of several of the Company offices did not comply with the Property Assessment Appeal Board, this resulted in a further $81,400 savings. Further, refunds totaling $52,900 were received in 2006 relating to the prior year appeals, with an expected $57,900 still expected to come.

3. **Miscellaneous Appeals** – The Company achieved a further reduction of $19,800 through various other appeals on valuation and classification.

4. **Other Activities** – Terasen Gas continues to be involved with a variety of groups specializing in Local Government taxation, these include the Canadian Property Tax Association, the Vancouver Board of Trade, and the Canadian Energy Pipeline Association.

Mitigation Activities in progress:

5. **Office Appeal** – In addition to the activities described under point #2, the Company is attempting to seek changes in the wording of the regulations. Terasen Gas met with Provincial Government officials to discuss changes in legislation to address the inequity in property classification applied to Utility offices. The Company is hopeful that changes

in legislation will be forthcoming for the 2008 taxation year. Based on the 2006 Assessment roll it is estimated a change in legislation would result in annual savings of $539,800.

CODE OF CONDUCT AND TRANSFER PRICING POLICY REVIEWS CONDUCTED BY INTERNAL AND INDEPENDENT EXTERNAL AUDITORS

The Commission stated, at page 21 of Appendix A to Commission Order G-51-03, the following relating to compliance with the 2004-2007 Negotiated Settlement:

> *"At each Annual Review, Terasen Gas will provide the report required by and filed with the Commission summarizing the results of the annual compliance review of the Code of Conduct and Transfer Pricing Policy of the Commission conducted by Terasen Gas' Internal Audit Services. For each year during the Term of the Settlement, the Commission will provide Stakeholders with the proposed Commission directions to Terasen Gas' Internal Audit Services. Any Stakeholder may request the Commission to add directions to review and report on other areas of concern."*

The Internal Audit Services has prepared a report entitled "Annual Review of Compliance with the Terasen Gas Inc. Code of Conduct and Transfer Pricing Policy" based on the same guidelines and framework as in 2005 and is attached as Appendix A to this Section B-5.

Furthermore, the Commission continued to state at page 22 of Appendix A:

> *"In addition, before the first Annual Review, Terasen Gas' independent external auditor will review the work performed by Terasen Gas' Internal Audit Services……Subsequent to the first Annual Review, Stakeholders and Terasen Gas may make submissions to the Commission regarding whether or not such a review and report by the independent external auditor of Terasen Gas should be continued for other Annual Reviews."*

For the 2006 Annual Review, Terasen Gas contracted the services of the firm PriceWaterhouseCoopers to provide a review of and report on Terasen Gas' compliance with the Code of Conduct ("CoC") and the Transfer Pricing Policy ("TPP"). PriceWaterhouseCoopers' report is attached as Appendix B.

Based on their respective review procedures, both internal and external auditors concluded that except for the financing of an affiliated company nothing came to their attention that would cause them to conclude that Terasen Gas is not in compliance with either of the CoC or TPP. The report by Internal Audit includes management's comments and actions undertaken to remedy the affiliate financing matter which arose as a result of timing of treasury transfers for payroll remittances following the assumption of payroll processing by TGI on behalf of Kinder

Morgan Canada Inc, on April 1, 2006. This shared service provides net benefits to utility customers. Kinder Morgan Canada Inc. has reimbursed all amounts due with interest resulting in no negative impact on customers.

TAB B-5 CODE OF CONDUCT AND TRANSFER PRICING POLICY COMPLIANCE

ATTACHMENT A – INTERNAL AUDIT REPORT

Terasen

W. Garner Dotson
Vice President, Internal Audit

(a subsidiary of Kinder Morgan, Inc.)

September 29, 2006

Mr. Randy Jespersen
President, Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C. V3S 2X7

Dear Sir:

Subject: **Annual Review of Compliance with the Terasen Gas Inc. Code of Conduct and Transfer Pricing Policy.**

Internal Audit has completed its' review of Terasen Gas Inc.'s (Terasen Gas) compliance with the Code of Conduct and Transfer Pricing Policy for the Provision of Utility Resources and Services (the Policies). This review is conducted to satisfy Terasen Gas's requirements as documented in the Policies.

> "Terasen Gas will monitor employee compliance with the Code of Conduct by conducting an annual compliance review, the results of which will be summarized in a report to be filed with the Commission (B.C. Utilities Commission) within 60 days of the completion of this review." [1]
>
> "The Transfer Pricing Policy will be reviewed on an annual basis as part of the Code of Conduct compliance review." [2]

Background

The Policies were issued in August 1997 to govern the relationships between Terasen Gas and Non-Regulated Business (NRB) for the provision of Utility resources. NRBs are defined as: "an affiliate of the Utility not regulated by the Commission or a division of the Utility offering unregulated products and/or services[3]". Terasen Gas has processes and practices that are designed to ensure compliance with these Policies.

Commission approval was obtained in July 2003 for the Terasen Gas Settlement Agreement for a 2004 - 2007 Performance-Based Rate Plan. One of the conditions for compliance with this negotiated settlement is that:

> "At each Annual Review, Terasen Gas will provide the report required by and filed with the Commission summarizing the results of the annual compliance review of the Code of Conduct and Transfer Pricing Policy of the Commission conducted by Terasen Gas' Internal Audit Services.
>
> In addition ... Terasen Gas' independent external auditor will review the work performed by Terasen Gas' Internal Audit Services and ..., consistent with Section 8600 of the CICA Handbook 'Review of Compliance with Agreements and Regulations', will provide a report of Terasen Gas' compliance with the Code of Conduct and Transfer Pricing Policy.[4]"

---

[1] Item 7 Compliance and Complaints, Code of Conduct
[2] Item 7 Review of Transfer Pricing Policy, Transfer Pricing Policy
[3] page 2 Definitions, both Code of Conduct and Transfer Pricing Policy
[4] Page 21 & 22, Appendix A, BCUC Order G-51-03

Review Objective

Consistent with prior years, the objective of this review is to determine whether the existing processes and controls that support compliance with the Policies are adequately designed and operating effectively during the period under review.

Review Approach

Our review of business processes and controls that support compliance with the Policies is made in accordance with Canadian generally accepted standards for review engagements as set out in the Canadian Institute of Chartered Accountants Handbook. Our enquiry, analytical procedures and discussion that we deemed necessary included the following:

- Review the Code of Conduct and Transfer Pricing Policy.
- Make enquires to understand the provision of Utility resources to NRBs.
- Make enquiries to understand the processes and controls maintained by Terasen Gas to comply with the Policies.
- Review evidence of such processes and controls and compliance with the Policies.

Conclusion

Item 8 of the Code of Conduct regarding Financing and Other Risks states:

> *[Terasen Gas] will not undertake any financing or other financial assistance on behalf of an NRB that exposes utility ratepayers to additional costs or risks, unless appropriate compensation is received by [Terasen Gas] for such financing or other financial assistance, and such financing or other financial assistance is approved by the Commission.*

Payroll processing for Kinder Morgan Canada [Affiliate] commenced April 1, 2006. The Affiliate was to transfer funds to Terasen Gas on or in advance of the pay date to cover the Affiliate's employee direct deposits and payroll remittances for payroll withholdings. Due to transitional challenges, the affiliate was unable to reconcile payroll amounts with transfer requests which delayed the transfer of funds to Terasen Gas. Terasen Gas paid the amount on the Affiliates behalf. For a 5 month period from April to August, the receivable balance from the Affiliate ranged from $349,000 to $6,985,000. The amount outstanding as at August is $581,000. It was management's intention to charge interest on the funds and was calculated at the higher of borrowing cost between Terasen Gas and the Affiliate. The interest amounts to $53,600 to the end of August but has not been recorded in the receivable account. As well, a committed service contract has not been finalized and is in progress at the time of this review thus no charges have been recorded or invoiced to the Affiliate. To ensure no future payroll funding is provided by Terasen Gas on behalf of the Affiliate, Management has put in place additional preventive controls. Terasen Inc. treasury will have a blanket authorization to transfer funds from the Affiliate to cover payroll and remittance amounts.

Based on my review, except for the financing of an affiliated company as described in the preceding paragraph, nothing has come to my attention that causes me to believe that Terasen Gas Inc. is not in compliance with the Code of Conduct and Transfer Pricing Policy for the period January 1, 2006 to August 31, 2006.

Specific Matters

1 Services provided to Terasen Energy Services (TES), an Affiliated company, commenced May 19, 2006. Internal Orders to capture time has been setup to record labour hours by field personnel. An Internal Order to capture time for back office functions (ie. financial management personnel) has not been setup but is being tracked separately. Charges to TES has not been calculated and invoiced on a timely basis. A service contract as at August 2006 was not finalized and still in progress.

2. A Non-pooled Specific Committed Service contract between Terasen International and Terasen Gas was in effect to the end of 2005. The contract has take or pay terms and at the end of 2005, there is $5,107 that has not been billed as at the end of August 2006.

3. Our survey of a representative sample of TGI employees identified a small minority of employees (6) who report being unaware of the Policies. These staff did not perform NRB work and, more importantly, our internal control that requires managerial approval of time sheets to detect and correct such error, if it did occur, was operating effectively.

Management Response

Management has reviewed the Annual Review of Compliance with the Terasen Gas Inc. Code of Conduct and Transfer Pricing Policy report completed by Internal Audit and is in agreement with the report's findings but provides the following comments[5]:

Terasen Gas Inc. commenced payroll processing for Kinder Morgan Canada in April 2006 and as at August there was an outstanding receivable balance from Kinder Morgan Canada of $581,000 related to the delayed transfer of payroll funds. As of September 29, 2006, Terasen Gas Inc. has received full payment for the $581,000. As well, Terasen Gas has invoiced and received payment for interest, in the amount of $53,600, related to the transitional delay of payroll fund transfers.

As of September 29, 2006, Terasen Gas Inc. is finalizing the services contract for the provision of payroll services to Kinder Morgan Canada and has invoiced and received payment in the amount of $97,110 for the payroll services provided from April 2006 to date consistent with the terms of the draft agreement and in accordance with the Transfer Pricing Policy.

Terasen Energy Services commenced operations May 2006 and has opted to receive services from Terasen Gas Inc. for field-related work under the "As Required Service" category of the Transfer Pricing Policy. The back office functions provided to Terasen Energy Services by Terasen Gas Inc. are covered under a services agreement which, as of September 29, 2006, has been finalized. As of September 29, 2006, Terasen Gas Inc. has invoiced Terasen Energy Services, and received payment, for the set-up costs incurred. Further, Terasen Gas Inc. will be invoicing Terasen Energy Services during the next month-end processing cycle for the back office services provided by Terasen Gas Inc. to the end of September 2006.

As of September 29, 2006, Terasen Gas Inc. has invoiced and received payment, in the amount of $5,107, related to the take or pay terms of the 2005 Specific Committed Services contract with Terasen International.

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[5] Specific action by Terasen Gas Inc. was not verified by Internal Audit.

We thank management and staff for their assistance and co-operation during our review.

W. Garner Dotson
VP, Internal Audit

cc: Kim Dang, CFO, Kinder Morgan Inc.
Stewart Bliss, Audit Committee Chair, Kinder Morgan, Inc.
Steven Kean, Executive Vice President, COO, Kinder Morgan, Inc.
Andrew Lee, Manager – Internal Audit, Kinder Morgan, Inc.
PriceWaterhouseCoopers
Park Shaper, President, Kinder Morgan, Inc.
Scott Thomson, Vice President, Finance & Regulatory Affairs & CFO, Terasen Gas Inc.
Perry Waughtal, Audit Committee Chair, Kinder Morgan Energy partners, L.P.
Deb Witges, Vice President and Controller, Kinder Morgan, Inc.

TAB B-5 CODE OF CONDUCT AND TRANSFER PRICING POLICY COMPLIANCE

ATTACHMENT B – EXTERNAL AUDIT REPORT

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
PricewaterhouseCoopers Place
250 Howe Street, Suite 700
Vancouver, British Columbia
Canada V6C 3S7
Telephone +1 604 806 7000
Facsimile +1 604 806 7806

REVIEW ENGAGEMENT REPORT

Mr. Scott Thomson
Vice President Finance and Regulatory Affairs and Chief Financial Officer
Terasen Gas Inc.

We have performed the procedures enumerated below, solely to assist you in evaluating Terasen Gas Inc's compliance for the eight month period from January 1, 2006 to August 31, 2006 with its Transfer Pricing Policy For Provision of Utility Resources and Services (the "Transfer Pricing Policy") and the Code of Conduct For Provision of Utility Resources and Services (the "Code of Conduct"), both dated August 1997, included in Terasen Gas' Internal Audit Services report on compliance with the Transfer Pricing Policy and Code of Conduct dated September 29, 2006.

Our review was made in accordance with Canadian generally accepted standards for review engagements and accordingly consisted primarily of enquiry, analytical procedures and discussion related to information supplied to us by the Company, including a review of Terasen Gas' Internal Audit Services report on compliance with the Transfer Pricing Policy and Code of Conduct dated September 29, 2006 and their work performed in connection with their report. Based on our review, except for the financing of an affiliated company as described in their report, nothing has come to our attention that causes us to believe that Terasen Gas Inc. is not in compliance with the Code of Conduct and Transfer Pricing Policy for the eight month period from January 1, 2006 to August 31, 2006.

These procedures do not constitute an audit of Terasen Gas' Internal Audit Services report on compliance with the Transfer Pricing Policy and Code of Conduct dated September 29, 2006 for the eight month period from January 1, 2006 to August 31, 2006, and accordingly, we express no opinion on that report. Had we performed additional procedures or had we made an examination of Terasen Gas' Internal Audit Services report on compliance with the Transfer Pricing Policy and Code of Conduct dated September 29, 2006, other matters might have come to our attention that would have been reported to you.

This report is intended solely for the information of the audit committee, management, and the other users of the report including the British Columbia Utilities Commission.

PricewaterhouseCoopers LLP

Chartered Accountants

Vancouver, Canada
October 6, 2006

TERASEN GAS (SQUAMISH) INC. AND TERASEN GAS INC. AMALGAMATION

Terasen Gas (Squamish) Inc. ("TGS") and the Province of B.C. (the "Province") have been involved in negotiations in an effort to reach a resolution of certain financial obligations as between those two parties. Over the course of the late summer and early fall, TGS and the Province were able to agree on a process to resolve these obligations. As part of the resolution of the financial obligations, TGS will be amalgamating with TGI effective January 1, 2007.

There are three agreements that determine the regulatory structure and operation of the TGS. These agreements are:

- Rate Stabilization Agreement ("RSA") – The RSA is an agreement between the Province and TGS that provides that the rates for customers in Squamish are set in relation to the rates of BC Hydro;
- Rate Stabilization Continuation Agreement ("RSFCA") – The RSFCA is an agreement between TGVI and the Province. It, in conjunction with the TSA, provide for the Province to fund TGS for any shortfall in revenues over costs. The RSFCA also provides for a fixed toll, for a set period, for transportation on the high pressure TGVI system; and
- Transportation Services Agreement ("TSA") – The TSA between TGS and TGVI provides for gas transportation service to TGS.

The effect of these agreements is that customers in TGS currently pay less than their cost of service. The Province subsidizes customer rates in Squamish through the mechanism of the payments made under the RSFCA.

Based upon discussions to date with the Province, TGS and TGI believe that the end result of the negotiations will be a payment being made by TGS shareholders to the Province that represents a negotiated and agreed settlement of the current and future obligations of TGS to the Province and the current and future obligations of the Province to TGS. A termination agreement will be put in place between TGI, TGVI, TGS and the Province that will terminate the RSA and RSFCA, and amend the TSA. TGI and TGS will also be amalgamated as part of the resolution. Government approval is required to effect the termination agreement and the TGI/TGS amalgamation.

Specifics of the termination and amalgamation include:

- TGI and TGS will amalgamate effective January 1, 2007, with the amalgamated entity being called TGI;
- Customers that were customers of TGS will, after December 31, 2006, be customers of the TGI Lower Mainland Service Area;
- The opening rate base of the amalgamated TGI, for rate making purposes, will be the combined rate base of TGI and TGS;
- The TSA amendments will result in the tolls for transport of gas on the TGVI system to the gas consumers in the Squamish area remaining at the same rate as is the effective toll under the current agreements. The toll payments for transportation of gas to Squamish will now be paid by the amalgamated TGI to TGVI. TGI will record these payments in the MCRA (actual dollar value to be determined as part of the Q4 gas cost reporting);
- For rate making purposes, for as long as the PBR settlement agreement is in effect, O&M for the amalgamated TGI will be as per the PBR;
- The common equity component of the capital structure for the amalgamated TGI will be the weighted average common equity of the two companies (thus resulting in no material difference as compared to the common equity of the two companies prior to amalgamation). Table 1, line 14, column 3 shows the resulting common equity component of Amalgamated TGI to be 35.01238%;
- The return on common equity for the amalgamated TGI will be the weighted average return on equity of the two companies. Table 1, line 14, column 4 shows the resulting Return on Common equity of amalgamated TGI, if the amalgamation had been in effect for 2006, would have been 8.80141%; and
- A deferral account will be created to record the expenses incurred to effect amalgamation as well as the difference in O&M between that of TGI under the PBR formula and that which would have been incurred for the TGS customers under the TGS formula O&M. This deferral account will not be recovered until after the expiry of the TGI PBR settlement.

Effect on Squamish Customers

As Lower Mainland customers of amalgamated TGI commencing January 1, the customers residing in the current TGS service area will receive service under the Terasen Gas Tariff and as such have the same rates and access to programs as all Lower Mainland customers. After amalgamation, current TGS residential customers will see their rates increase by approximately 10%, depending upon consumption; however larger commercial customers who will be served under Rate Schedule 3 will see a slight drop in their annual rates[1]. Additionally, customers in Squamish will also be eligible for all Terasen Gas programs such as Commercial and Residential Unbundling, DSM Programs, and other incentive programs. Perhaps most importantly, Main Extension Tests ("MX Test") will be the test in the Terasen Gas Tariff. Individual MX Tests will no longer require review by the Province and the BCUC. This will result in a more streamlined approval process of main extensions and will help amalgamated TGI add customers in the Squamish area.

Effect on TGI Customers

Customers who are currently customers of Terasen Gas will see little change as a result of the amalgamation; the amalgamation will occur within the framework of the PBR. As noted above, the resulting return on common equity for amalgamated TGI is the weighted average of the returns on equity of the two utilities, but since the TGI rate base is much larger than that of TGS, the effect on the return on equity of the amalgamated company is very small. Table 1, line 14, column 6 shows the return on common equity for amalgamated TGI of $76,246,000, which is equal to the return on common equity of TGS (but for amalgamation) on line 38, column 6 of $228,000 plus the return on common equity of TGI (but for amalgamation) on line 62 column 6 of $76,018,000. Additionally, financing costs of amalgamated TGI are $76,000 less that they would have been for TGI and TGS but for amalgamation. As such, the total earned return (column 6) is less for amalgamated TGI than what would have been the earned return for TGS and TGI but for amalgamation which benefits customers. TGI customers will see a small increase in cost of service post PBR upon amortization of the TGS deferral accounts.

Changes to the MCRA charge resulting from the gas transportation charge paid by amalgamated TGI to TGVI for the transportation of gas to Squamish will be determined as part of the Q4 gas cost reporting. Based upon TGS annual volume of 379,000 GJ, toll payments recorded in the MCRA will be approximately $397,950. Based upon sales volumes for TGI and TGS combined (Section A Tab 4, Page 12), this would result in an increase to midstream rates of $0.0034/GJ.

[1] Note: if TGS were to stay a separate utility and was no longer receiving subsidy from the Province, rates would increase a similar amount.

TABLE 1 - RETURN ON CAPITAL

RETURN ON CAPITAL

FOR THE YEAR ENDING DECEMBER 31, 2007

($000)

Line No.	Particulars		Capitalization Amount	%	Embedded Cost	Cost Component	Earned Return
	(1)		(2)	(3)	(4)	(5)	(6)
	AMALGAMATED TGI (TGI + TGS)						
1	2007 at Existing Rates						
2	Long-Term Debt		$1,470,051	59.41%	7.018%	4.170%	
3	Unfunded Debt		137,892	5.57%	4.750%	0.265%	
4	Preference Shares		0	0.00%	0.000%	0.000%	
5	Common Equity		866,288	35.01%	9.120%	3.193%	
6							
7			$2,474,231	100.00%		7.628%	
8							
9	2007 REVISED RATES						
10	Long-Term Debt		$1,470,051	59.41%	7.018%	4.170%	$103,162
11	Unfunded Debt	$137,892					
12	Adjustment, Revised Rates	12	137,904	5.57%	4.750%	0.265%	6,550
13	Preference Shares		0	0.00%	0.000%	0.000%	0
14	Common Equity		866,293	35.01238% *	8.80141% **	3.082%	76,246
15							
16			$2,474,248	100.00%		7.516%	$185,958
17							
18							
24	**TERASEN GAS (SQUAMISH) INC.**						
25	2007 at Existing Rates		$3,336	54.46%	7.018%	3.822%	
26	Long-Term Debt		339	5.54%	4.750%	0.263%	
27	Unfunded Debt		0	0.00%	0.000%	0.000%	
28	Preference Shares		2,450	40.00%	9.120%	3.648%	
29	Common Equity						
30			$6,125	100.00%		7.722%	
31							
32							
33	2007 REVISED RATES		$3,336	54.47%	7.018%	3.822%	$234
34	Long-Term Debt	$339					
35	Unfunded Debt	(0)	339	5.53%	4.750%	0.263%	16
36	Adjustment, Revised Rates		0	0.00%	0.000%	0.000%	0
37	Preference Shares		2,450	40.00%	9.300%	3.720%	228
38	Common Equity						
39			$6,125	100.00%		7.804%	$478
40							
41							
48	**TERASEN GAS INC.**						
49	2007 at Existing Rates		$1,470,051	59.56%	7.018%	4.180%	
50	Long-Term Debt		134,218	5.44%	4.750%	0.258%	
51	Unfunded Debt		0	0.00%	0.000%	0.000%	
52	Preference Shares		863,837	35.00%	9.120%	3.192%	
53	Common Equity						
54			$2,468,106	100.00%		7.630%	
55							
56							
57	2007 REVISED RATES		$1,470,051	59.56%	7.018%	4.180%	$103,162
58	Long-Term Debt	$134,218					
59	Unfunded Debt	11	134,229	5.44%	4.750%	0.258%	6,376
60	Adjustment, Revised Rates		0	0.00%	0.000%	0.000%	0
61	Preference Shares		863,843	35.00%	8.800%	3.080%	76,018
62	Common Equity						
63			$2,468,123	100.00%		7.518%	$185,556
64							
65							
66	**Notes:**						
67	* TGS Equity $2,450 + TGI Equity $863,843 = Amalgamated Equity $866,293. Amalgamated Equity Thickness 35.01238% = Amalgamated Equity $866,293 / Amalgamated Rate Base $2,474,248.						
68	** TGS ROE $228 + TGI ROE $76,018 = Amalgamated Return on Equity $76,246. Amalgamated ROE 8.80141% = Amalgamated ROE $76,246 / Amalgamated Equity $866,293.						

TABLE 2 - EARNED INCOME

UTILITY INCOME AND EARNED RETURN

FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

		ALMAGAMATED TGI (TERASEN GAS INC. + TERASEN GAS (SQUAMISH) INC.)			TERASEN GAS (SQUAMISH) INC.			TERASEN GAS INC.		
			----Revised Rates-----			----Revised Rates-----			----Revised Rates-----	
Line No.	Particulars	Existing Rates	Revised Revenue	Total	Existing Rates	Revised Revenue	Total	Existing Rates	Revised Revenue	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ENERGY VOLUMES (TJ)									
2	Sales	116,776		116,776	379		379	116,397	0	116,397
3	Transportation	95,397		95,397	0		0	95,397	0	95,397
4		212,173	0	212,173	379	0	379	211,794	0	211,794
5										
6	Average Rate per GJ									
7	Sales	$11.904		$11.873	$12.145	$0.079	$12.224	$11.903	$0.000	$11.873
8	Transportation	$0.787		$0.782			$0.000	$0.787	$0.000	$0.782
9	Average	$6.906		$6.886	$12.145	$0.079	$12.224	$6.896	$0.000	$6.877
10										
11	UTILITY REVENUE									
12	Sales - Existing Rates	$1,390,101		$1,390,101	$4,603		$4,603	$1,385,498	$0	$1,385,498
13	- Increase / (Decrease)		(3,617)	(3,617)		30	30	0	(3,565)	(3,565)
14										
15	Transportation - Existing Rates	75,080		75,080			0	75,080	0	75,080
16	- Increase / (Decrease)		(512)	(512)			0		(506)	(506)
17	**Total**	1,465,181	(4,129)	1,461,052	4,603	30	4,633	1,460,578	(4,071)	1,456,507
18										
19	Cost of Gas Sold (Including Gas Lost)	966,880		966,880	3,130	0	3,130	963,750	0	963,750
20										
21	**Gross Margin**	498,301	(4,129)	494,172	1,473	30	1,503	496,828	(4,071)	492,757
22										
23	Operation and Maintenance (**FORMULA O&M**)	169,272		169,272	662		662	168,610	0	168,610
24	Vehicle Lease	1,993		1,993	0		0	1,993	0	1,993
25	Property and Sundry Taxes	44,452		44,452	101		101	44,351	0	44,351
26	Depreciation and Amortization (**FORMULA DEP'N**)	84,701		84,701	199		199	84,502	0	84,502
27	Other Operating Revenue (**FORMULA LPC**)	(24,910)		(24,910)	(21)		(21)	(24,889)	0	(24,889)
28		275,508	0	275,508	941	0	941	274,567	0	274,567
29	Utility Income Before Income Taxes	222,793	(4,129)	218,664	532	30	562	222,261	(4,071)	218,190
30										
31	Income Taxes	34,068	(1,362)	32,706	74	10	84	33,978	(1,344)	32,634
32										
33	**EARNED RETURN**	$188,725	($2,767)	$185,958	$458	$20	$478	$188,283	($2,727)	$185,556
34										
35	**UTILITY RATE BASE**	$2,474,231	$17	$2,474,248	$6,125	($0)	$6,125	$2,468,106	$17	$2,468,123
36										
37	**RATE OF RETURN ON UTILITY RATE BASE**	7.628%		7.516%	7.470%		7.804%	7.630%		7.518%

TABLE 3 - RATE BASE

UTILITY RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	ALMAGAMATED TGI (TERASEN GAS INC. + TERASEN GAS (SQUAMISH) INC.) 2006 Rates	Adjustments	Revised Rates	TERASEN GAS (SQUAMISH) INC. 2006 Rates	Adjustments	Revised Rates	TERASEN GAS INC. Existing Rates	Adjustments	Revised Rates
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Plant in Service, Beginning	$3,140,710	$0	$3,140,710	$0	$0	$0	$3,140,710	$0	$3,140,710
2	CPCNs	8,137	0	8,137	8,137	0	8,137	0	0	0
3										
4	Additions	129,717	0	129,717	858	0	858	128,859	0	128,859
5	Disposals	(32,918)	0	(32,918)	(87)	0	(87)	(32,831)	0	(32,831)
6										
7	Plant in Service, Ending	3,245,646	0	3,245,646	8,908	0	8,908	3,236,738	0	3,236,738
8										
9	Add - Intangible Plant	1,614	0	1,614	777	0	777	837	0	837
10										
11		3,247,260	0	3,247,260	9,685	0	9,685	3,237,575	0	3,237,575
12										
13	Contributions In Aid of Construction	(131,162)	0	(131,162)	(728)	0	(728)	(130,434)	0	(130,434)
14										
15	Less - Accumulated Depreciation	(744,227)	0	(744,227)	(2,102)	0	(2,102)	(742,125)	0	(742,125)
16										
17										
18	Net Plant in Service, Ending	$2,371,871	$0	$2,371,871	$6,855	$0	$6,855	$2,365,016	$0	$2,365,016
19										
20										
21	Net Plant in Service, Beginning	$2,339,687	$0	$2,339,687	$6,924	$0	$6,924	$2,332,763	$0	$2,332,763
22										
23										
24	Net Plant in Service, Mid-Year **PBR FORMULA NPIS**)	$2,355,779	$0	$2,355,779	$6,889	$0	$6,889	$2,348,890	$0	$2,348,890
25	Adjustment to 13-Month Average	0	0	0	0		0	0	0	0
26	Construction Advances	(11)	0	(11)	0		0	(11)	0	(11)
27	Work in Progress, No AFUDC	10,771	0	10,771	0		0	10,771	0	10,771
28	Unamortized Deferred Charges	(8,227)	0	(8,227)	120		120	(8,347)	0	(8,347)
29	Cash Working Capital	(25,214)	17	(25,197)	(692)	0	(692)	(24,522)	17	(24,505)
30	Other Working Capital	143,982	0	143,982	50		50	143,932	0	143,932
31	Deferred Income Tax, Mid-Year	(606)	0	(606)	(242)		(242)	(364)	0	(364)
32	LILO Benefit	(2,243)	0	(2,243)			0	(2,243)	0	(2,243)
33	Utility Rate Base	$2,474,231	$17	$2,474,248	$6,125	$0	$6,125	$2,468,106	$17	$2,468,123
34										
35	Capital Structure - Debt Financing	64.98763%		64.98762%	60%		60%	65%		65%
36	Capital Structure - Equity Thickness	35.01237%		35.01238% *	40%		40%	35%		35%
37	Capital Structure - Equity Investment (Line 33 * Line 36)	$866,287		$866,293	$2,450		$2,450	$863,837		$863,843
38										

39 **Notes:**

40 * TGS Equity $2,450 + TGI Equity $863,843 = Amalgamated Equity $866,293. Amalgamated Equity Thickness 35.01238% = Amalgamated Equity $866,293 / Amalgamated Rate Base $2,474,248.

TABLE 4 - INCOME TAX

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

		ALMAGAMATED TGI (TERASEN GAS INC. + TERASEN GAS (SQUAMISH) INC.)			TERASEN GAS (SQUAMISH) INC.			TERASEN GAS INC.		
			----Revised Rates-----			----Revised Rates-----			----Revised Rates-----	
Line No.	Particulars	Existing Rates	Revised Revenue	Total	Existing Rates	Revised Revenue	Total	Existing Rates	Revised Revenue	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	CALCULATION OF INCOME TAXES									
2	Earned Return	$188,725	($2,767)	$185,958	$458	$20	$478	$188,283	($2,727)	$185,556
3	Deduct - Interest on Debt	(109,712)	0	(109,712)	(250)	1	(250)	(109,537)	(1)	(109,538)
4	Add- Non-Tax Ded. Expense (Net)	(2,290)		(2,290)			0	(2,290)	0	(2,290)
5										
6	Accounting Income After Tax	76,723	(2,767)	73,956	208	21	229	76,456	(2,728)	73,728
7	Add (Deduct) - Timing Differences	(7,553)	0	(7,553)	(57)	0	(57)	(7,471)	0	(7,471)
8	Add - Large Corporation Tax	0		0			0	0	0	0
9										
10	Taxable Income After Tax	$69,170	($2,767)	$66,403	$151	$21	$172	$68,985	($2,728)	$66,257
11										
12	Income Tax Rate (Current Tax)	33.000%	33.000%	33.000%	33.000%	33.000%	33.000%	33.000%	33.000%	33.000%
13	1 - Current Income Tax Rate	67.000%	67.000%	67.000%	67.000%	67.000%	67.000%	67.000%	67.000%	67.000%
14								0	0	0
15	Taxable Income (L10 / L13)	$103,238	($4,129)	$99,109	$225	$30	$255	$102,963	($4,072)	$98,891
16										
17	Income Tax - Current (L12 x L15)	$34,068	($1,362)	$32,706	$74	$10	$84	$33,978	($1,344)	$32,634
18								0	0	0
19	- Large Corporation Tax			0			0	0	0	0
20										
21	Total	$34,068	($1,362)	$32,706	$74	$10	$84	$33,978	($1,344)	$32,634
22										
23										
24	REVENUE DEFICIENCY									
25	Earned Return		($2,767)	$185,958		$20	$478		($2,727)	$185,556
26	Add - Income Taxes		(1,362)	32,706		10	84		(1,344)	32,634
27	Deduct - Utility Income Before Taxes,									
28	Existing Rates			(222,793)			(532)		0	(222,261)
29	Corporate Capital Tax			0			0		0	0
30										
31	Deficiency/(Surplus) After Corporate Capital Tax		($4,129)	($4,129)		$30	$30		($4,071)	($4,071)

EXOGENOUS FACTORS

Terasen Gas is permitted to adjust the cost of service for "Exogenous Factors" pursuant to the provisions of the 2004-2007 Settlement Agreement (Appendix A, Page 14).

Terasen has identified one item that merits exogenous treatment under the judicial, legislative or administrative changes, orders and directions section of the Settlement Agreement.

1. Provincial Sales Tax ("PST") reassessment

As a result of a recent audit conducted by the B.C. Ministry of Small Business and Revenue ("MSBR"), Terasen Gas has been assessed approximately $36 million under the Social Services Tax Act related to the construction of the Southern Crossing Pipeline Project for the audit period August 1, 2000 to November 30, 2005.

The MSBR is taking the view that the pipe and compressors are tangible personal property and has assessed PST on the services to install the pipeline on the basis that labour services to tangible personal property are taxable. Under the terms of the CPCN approving the construction of the SCP, a spending cap of $414 million was imposed. PST on the project would ordinarily be included in the plant costs subject to availability under the spending cap.

Terasen Gas does not agree with the reassessment and has obtained legal advice that the reassessment should not stand up on appeal, however some risk remains that some or all of the reassessed amounts will be sustained. Terasen Gas is appealing, and while these reassessments are being appealed, Terasen Gas will remit a $10 million payment to prevent further accrual of interest, which will be refundable with interest in the event Terasen Gas is successful on appeal. Accordingly, Terasen seeks to collect in a rate base deferral account, the $10 million payment along with cost of the appeal since these are imposed on Terasen Gas by outside authorities over which the Company has no control. When the appeal is resolved, Terasen will seek a Commission order with respect to the disposition of the deferral account.

1. INTRODUCTION

Under the terms of the 2004 – 2007 Multi-Year Performance Based Rate Plan Settlement ("PBR"), Terasen Gas Inc. ("Terasen Gas" or "TGI") is required to submit a mid-term assessment review in year three (2006). This review invites the opportunity to extend the time frame of the PBR. As part of the PBR Settlement, Terasen Gas committed to focus on operational excellence to maximize benefits in the areas of Operating and Maintenance expenses ("O&M") and capital expenditures, while maintaining reliability, service and safety-related standards. To the extent that efficiencies are achieved, the benefits of these efficiencies are shared with customers. Key accomplishments and financial efficiencies experienced through the PBR period to date are summarized in this report.

2. KEY ACCOMPLISHMENTS

In order to achieve operational efficiencies and realize financial benefits for Terasen Gas and its customers, a number of challenges needed to be overcome. The following are key accomplishments achieved during 2004 to 2006.

Restructuring and Integration of Terasen Gas Inc. with Terasen Gas (Vancouver Island) Inc. ("TGVI")

The successful execution of productivity improvements was made possible by the restructuring and integration activities of TGI with TGVI. The integration revolved around a shared service approach to managing the operations that enabled both companies to harness the benefits from economies of scale by having a single management team and back office support structure that avoids duplication of work and allows customers to benefit from synergies created, financially and through enhanced service levels. The transition to common management, processes and technologies, while challenging to execute, resulted in savings and benefits of approximately $8.0 million per year to TGI and $2.0 million per year to TGVI starting in 2004. Restructuring resulted in a reduction of 56 employees at TGI and 59 employees at TGVI while maintaining TGI's ability to meet service quality indicator benchmarks in all material respects and focus on safe and reliable service delivery.

Unbundling Initiatives

The flexible structure of the PBR Agreement has not precluded Terasen Gas from undertaking major new initiatives during the settlement period. A significant undertaking during the last 3 years was the roll out of commodity unbundling and commodity supplier choice for customers. The provision of more customer choice by offering options to lock-in their commodity rates over a fixed time frame has been enabled through the Unbundling Initiatives.

The commercial phase of the unbundling program was launched successfully in November 2004, offering commercial customers the ability to lock in their commodity rate for terms up to five years. Since its startup, over 18,000 commercial customers have chosen to participate in the program. The Residential phase was recently approved by the Commission with the startup date targeted for November 2007.

The Stable Rate pilot program was launched for calendar year 2005, providing residential customers the ability to lock in their commodity charge for a 1 year term. In its first year, approximately 1,800 residential customers participated in the offering. The second year of the program saw 8,000 residential customers participate. The third year was of the offering is being marketed from October 1 - November 30, 2006 providing residential customers that ability to fix their commodity rate for calendar year 2007.

The PBR model has been flexible enough to allow such changes to take place.

Increased Market Share of Multi-family Dwellings

Terasen Gas is working towards capturing a larger share of the multi-family dwelling segment's space and hot water heating needs. The Company has focused it efforts in three broad areas during the past several years. First it is working with government, industry and BC Hydro to promote the most effective use of energy based on the application. The second area of focus has been providing multi-family customers the ability to gain greater control over their energy usage and costs through expansion of individual suite metering. Third is developing programs that help promote efficiency technologies. All the above actions are aligned with a key message of Terasen Gas- "right fuel, right place, right time" - and support the Company’s position that natural gas is the most suitable fuel for space and water heating and should displace electricity in these applications.

Commodity Price Risk Management

The key goals of Terasen Gas' hedging strategy's are to dampen commodity price volatility and to maintain a competitive position vis-à-vis electricity prices. This program has maintained customer gas rates below that of the BC Hydro electric equivalent rate since January 2004. With the price risk management program currently in place for the gas year 2006/07, there is a 95% probability of maintaining rates under the electric equivalent.

Terasen Gas and Terasen Gas (Vancouver Island) submitted their Resource Plans for the Mainland and Vancouver Island on July 31, 2006 for review by the Commission. Since then, Terasen Gas has met with various stakeholders to review and discuss the implementation of the recommendations presented by the plans.

Improve Employee Engagement

Employee engagement contributes to the organization's success through a dedicated workforce committed to optimizing customer service and performance. During the PBR period, the company has increasingly involved employees across and at all levels of the organization in the strategic and business planning processes that has measurably increased employee engagement. A 2005 Employee Survey reported that 35 percent of respondents had increased their level of engagement at work compared to the prior year and overall voluntary employee participation in the survey increased by 10 percent. Increasing employee engagement levels continues to remain a priority for 2006 and beyond.

A new five-year contract was reached with the International Brotherhood of Electrical Workers ("IBEW") through the collective bargaining process on July 31, 2006. The IBEW represents 550 Terasen Gas employees working primarily in gas distribution and transmission including functions such as installations, emergency response and the repair and maintenance of the gas pipeline system. The new contract gives the company stability for planning and operational purposes to continue to meet customers' needs and service levels.

3. SERVICE QUALITY ASSURANCE

The PBR Settlement agreement includes a commitment by Terasen Gas to maintain existing high levels of service quality during the PBR term. Parties to the settlement agreed to specific Service Quality Indicators ("SQI") with benchmarks where applicable.

While delivering financial benefits to customers through built in productivity targets under the PBR formulae and further through shared savings on O&M and capital expenditures, there has been no adverse effect on Service Quality Indicators. All SQI benchmarks were materially met over the PBR period to date.

Operational performance indicators including call answer speed, billing accuracy and meter exchange appointments have exceeded the set benchmark. Customer satisfaction benchmarks measuring independently surveyed customer satisfaction levels and as well as the number of prior period adjustments for industrial transport service have improved during the PBR period. There has been no deterioration of system integrity measures for number of third party damages or leaks per kilometre of distribution mains.

Two measures have been slightly off benchmark targets but have shown improvement over the PBR period. Emergency response time has been nominally higher than benchmark, primarily due to increased traffic congestion and construction activity in the Lower Mainland. Throughout the PBR period this measure has never been more than 36 seconds off the benchmark. In 2004 and 2005, three reportable transmission system incidents occurred, exceeding the benchmark of two, by one incident. None of the reportable incidents were serious in nature. To date in 2006 there have been no reportable incidents.

Finally, the number of customer complaints to the BCUC has declined over the PBR period. The majority of complaints made have dealt with billing and collection matters which tend to spike during the heating season and around rate changes.

A summary of the Service Quality Indicators and benchmarks are provided in the tables below. Further details on SQIs can be found in Tab B-2 of this submission.

Service Quality Indicators and Benchmarks

	Performance Indicators	Benchmarks	2004	2005	2006 (Jan-Aug)
1	Emergency Response Time	<= 21.1mins	21.6mins	21.7mins	21.4mins
2	Speed of Answer - Emergency	>= 95.0%	97.9%	98.8%	99.0%
3	Speed of Answer - Non Emergency	>= 75.0%	77.5%	76.9%	77.9%
4	Transmission System Integrity	<= 2	3	3	0
5a	Res. & Comm. Customer Billing Activity	<= 5	1.93	1.97	0.70
5b	Industrial Customer Billing Activity	>= 99.5%	96.6%	99.9%	99.9%
6	Meter Exchange Appointment Activity	>= 92.2%	93.5%	94.3%	94.5%
7	Industrial Meter Measurement	>= 90.0%	98.0%	99.5%	99.2%
8	Customer Satisfaction	N/A-compare to prior years	75.3%	77.2%	77.0%
9	Customer Satisfaction (Customer Complaints to BCUC)	N/A-compare to prior years	191	121	114
10	Customer Satisfaction (# of Prior Period Adjustments)	N/A-compare to prior years	18	14	15

	Directional Indicators	2004	2005	2006 (Jan-Aug)
1	Number of Third Party Damages	1,492 incidents	1,457 incidents	1,023 incidents
2	Leaks per Km of Distribution Mains	0.0045 (150 leaks)	0.0034 (120 leaks)	0.0016 (58 leaks)

4. FINANCIAL OUTCOMES

The PBR has been financially beneficial for all parties. Savings have been achieved through effective management, operational efficiencies and discipline in capital spending which have delivered built in productivity gains for customers as well as sharing of enhanced earnings of the Company.

Return On Equity

	2004	2005	2006P	Average
ROE - Achieved Before Earnings Sharing	9.34%	10.78%	10.10%	10.08%
ROE - Approved	9.15%	9.03%	8.80%	8.99%
Achieved Incentive ROE Before Earnings Sharing	0.19%	1.75%	1.30%	1.08%
Achieved Incentive ROE After Earnings Sharing	0.10%	0.88%	0.65%	0.54%
ROE - Achieved After Earnings Sharing	9.25%	9.91%	9.45%	9.53%

Based on the three-year average from 2004 to 2006 (projected), Terasen Gas' expects to achieve average incentive returns after earnings sharing of approximately 0.54%. A Commission review of the PBR can be triggered if the achieved ROE, after earnings sharing, varies from the allowed ROE by greater than 150 basis points in any year of the settlement term. The achieved ROE after earnings sharing has been within this band in each year of the term to date.

The incentive earnings were nominal in the first year reflecting the costs of integration and restructuring and the phasing in of benefits. They are highest in year two and are now declining as the built in productivity challenge increases in the final two years of the settlement and because labour inflation has greatly exceeded the general level of inflation reflected in the PBR formulas.

Earning Sharing Benefit

The PBR has provided financial benefits to all parties. The following table illustrates that by the end of 2006, it is estimated that $19.9 million dollars of achieved savings will have been credited to customers through the earning sharing mechanism.

	2004	2005	2006P	Total
Rate Base	$2,307	$2,408	$2,428	
Common Equity Component	$761	$795	$850	
Achieved ROE on Common Equity	9.344%	10.784%	10.098%	
Approved ROE on Common Equity	9.150%	9.030%	8.800%	
ROE Surplus	0.194%	1.754%	1.298%	
After Tax Surplus Earnings	$1.5	$13.9	$11.0	
50:50 Sharing with Customers	$0.7	$7.0	$5.5	
Customers' Share of Pre-Tax Surplus	$1.1	$10.5	$8.2	$19.9

O&M savings through initiatives such as the restructuring and integration of TGI with TGVI contributed approximately $17 million dollars to the credit with the remaining $2.9 million savings coming from optimizing capital spending. The longer-term nature of the PBR settlement allowed the company to undertake restructuring investments to generate savings which will provide long-term gains to customers. Because of the significant productivity gains realized through successive rounds of PBR settlements, it becomes increasingly costly to pursue incremental efficiency gains (the phenomena of declining returns over time). Successively longer PBR terms may be required in future to provide sufficient time to recoup investments.

As illustrated in the table below, delivery rates have increased in nominal terms by an average of only 0.22% per annum over the term of the PBR while the average inflation has been approximately 2%. In real terms there has been an average decrease to delivery rates as a percent of revenues of 1.76% per year over the past 4 years.

Customer Rate Changes compared to Inflation (in millions of dollars)

	2004	**2005**	**2006P**	**2007F**	**4-year Average**
Revenue Deficiency (Surplus)	19.2	(2.2)	19.8	(4.1)	8.2
Earnings Sharing		0.3	(7.3)	(12.7)	(4.9)
Annual increase (decrease) in revenue requirement	19.2	(1.9)	12.5	(16.8)	3.3
Increase as a % of Revenue	1.38%	-0.14%	0.76%	-1.13%	0.22%
Increase as a % of Margin	4.09%	-0.38%	2.55%	-3.29%	0.74%
Inflation	1.70%	2.00%	2.20%	2.00%	1.98%
Average increase in delivery rates as a % of revenues adjusted for inflation					**-1.76%**

Capital Incentives

The PBR provides an opportunity for the Company to achieve incentive returns by effectively managing capital expenditures. Variances between formula-based and actual base capital expenditures are reflected in differences between the formula-based revenue requirement and the revenue requirements associated with the actual capital spending levels. Such variances are shared with customers through the earnings sharing mechanism. As noted above, the customers' share of these benefits is expected to be $2.9 million for the first three years of the PBR.

As part of its Annual Review submission, Terasen Gas provides its Five Year Regular Capital and Major Capital Plans, which specifically identifies and provides descriptions of all major projects anticipated to cost over $1 million. Consistent with Terasen Gas's intention to balance safety and reliability requirements with prudent capital planning, the development of these plans has been incorporated into Terasen Gas's internal budgeting process. Terasen Gas believes that the inclusion of both Capital Plans in the Annual Review process has enabled Terasen Gas to be more transparent to its stakeholders and that this added step has resulted in project planning taking place earlier in the process.

During the PBR period, Terasen Gas has adopted standardized System Capacity Planning methodology across all its regions. The Company has also developed System Integrity Programs, increased its focus on asset management and implemented a centralized Project Management Office to coordinate and more effectively execute capital plant installations. These changes have contributed to lower than forecast system reliability and integrity capital expenditures while meeting safety and reliability requirements.

Together these process changes have contributed to efficiency gains which have helped Terasen Gas reduce capital expenditure levels below that allowed by formula during the PBR period.

4. SUMMARY

Terasen Gas believes the PBR settlement has been a success for customers and the Company alike. Operational excellence and integration between the Terasen gas utility operations across British Columbia continues to be management's focus. Safety, reliability, and customer service quality and satisfaction remain the key business drivers with a continuing focus on cost containment. The PBR settlement incents the Company to continue to pursue these objectives with vigour.

Along with financial benefits, stakeholders have experienced more streamlined regulatory processes through reduced hearing time and cost while maintaining a high degree of interaction with the Company and other interested parties through frequent and regular meetings including the semi-annual Customer Advisory Council presentations. As well there has been a high degree of ongoing regulatory oversight by the Commission through the Annual Review and rate setting process, Quarterly Gas Cost Review filings, annual reporting and financing related applications. Major capital projects exceeding $5 million in value must proceed through the formal CPCN application process.

Looking forward, Terasen Gas believes it would be appropriate to extend the time frame of the present PBR Settlement beyond 2007. The company expects increasing financial pressures in 2007 and beyond due to the impact of economic conditions in Western Canada driving higher labour and material costs. An extension of the current PBR model and settlement period will contribute to continued alignment between Terasen Gas and its customer's interests where any benefits realized through further capital and operational efficiencies will be shared.