Terasen Gas

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November 2, 2007

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("Terasen Gas")
2007 Annual Review of 2008 Revenue Requirements

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

On October 5, 2007, Terasen Gas filed its Advance Materials for the 2007 Annual Review of 2008 Revenue Requirements. In accordance with Commission Order No. G-112-07 setting out the Regulatory Timetable for the Application.

TGI respectfully submits the attached response to BCUC IR No. 1. TGI wishes to note that these responses reflect the TGI November 2, 2007 Revised Annual Review Filing (Exhibit B-1-3).

The response to Question 15.1 will be delayed as TGI is currently experiencing difficulties with the billing data required to complete this request. Efforts are underway to resolve this issue and the response to this question will be provided as soon as the necessary data becomes available.

If there are any questions regarding the attached, please contact Mr. Tom Loski, Director, Regulatory Affairs at (604) 592-7464.

Yours very truly,

TERASEN GAS INC.

Original signed

For: Scott A. Thomson

Attachment

cc (e-mail only): TGI Multi Year PBR (2004-2007 PBR & 2008-2009 Extension) Participants and 2006 Annual Review & Mid-Term Settlement Update Participants

1.0 Reference: Exhibit B-1, Section A-1, 2008 Revenue Requirement, pp. 2 and 4

"The reduction in use rates contributes $7.8 million of the revenue requirement increase before earnings sharing. The change in use rates is offset in part by customer growth which reduces revenue requirement by $5.4 million, but which in turn contributes to revenue requirement increases of $2.6 million due to a higher rate base".

1.1 Please reconcile the customer use rate and customer growth revenue requirements on Exhibit B 1, Section A, Tab 1, p. 2 to the $4.2 million increase due to Customer Growth and Use in the Summary of the 2008 Revenue Requirement Decrease schedule on Exhibit B-1, Section A 1, p. 4.

Response:

Volume/Revenue Related Variance

1	Lower Revenue Requirement from Change in Gross Margin due to Customer Growth (RSAM Classes)	$ (5,377)
2	Higher Revenue Requirement from Change in Gross Margin due to lower Use Rates (RSAM Classes)	7,804
3	All Others	1,835
		$ 4,262

1 Change in Gross Margin due to Customer Growth

	Change in Avg. Customers		2007 Approved Margin / Customer ($000s)		Margin Impact ($000s)
Rate 1 - Residential	9,121	x	$0.4	=	$3,743.8
Rate 2 - Small Commercial	545	x	1.0	=	552
Rate 3 - Large Commercial	(165)	x	8.2	=	(1,354)
Rate 23 - Commercial Transportation	199	x	12.3	=	2,436
	9,700				**$5,377.3**

2 Change in Gross Margin due to change in Use Rates

	Change in Use Rate (GJs)		2007 Average Customers		2007 Approved Margin $ / GJ ($000s)		Margin Impact ($000s)
Rate 1 - Residential	(3.5)	x	739,474	x	$0.004	=	($10,651.8)
Rate 2 - Small Commercial	8.2	x	73,862	x	0.003	=	1,949.5
Rate 3 - Large Commercial	86.1	x	4,670	x	0.002	=	987.7
Rate 23 - Commercial Transportation	(31.4)	x	1,147	x	0.002	=	(89.2)
	59.4		**819,153**				**($7,803.9)**

3 All Others

	Volumne Imapct (TJs)	Margin Impact ($000s)
Rate 22 - Large Volume Transportation	(2,661)	($467.0)
Rate 25 - General Firm Transportation	(755)	(270.0)
Rate 27 - General Interruptible Transportation	(1,234)	(1,098.0)
	(4,650)	**($1,835.0)**

2.0 Reference: Exhibit B-1, Section A-1, 2008 Revenue Requirement, p. 4

2.1 Please provide a breakdown of the $15.0 million of Earnings Sharing in the same format as the 2006 Annual Review and Mid-Term Assessment Review Response to BCUC IR 1.2

Response:

A breakdown of the $15.0 million of Earnings Sharing is as follows:

	($ Millions)
2006 Actual Earnings Sharing	$ 10.7
less: 2006 Projected Earnings Sharing	8.2
2006 Earnings Sharing True-Up	2.4
2007 Projected Earnings Sharing	12.6
Total Earnings Sharing	$ 15.0

2.2 Please show the calculation and explain how the forecast interest rate used in the 2008 Revenue Requirement was determined. Provide all references.

Response:

The calculation of the $2.3 million higher interest expense for 2008 Forecast compared to 2007 Approved as identified on Section A, Tab 1, Page 4 is as follows:

Particulars	Principal	Old Rates	New Rates	Change
2007 Unfunded Debt	137,943	4.750%	5.000%	345
2007 Long Term Debt	1,470,051	7.018%	7.231%	3,127
2008 Unfunded Debt to refinance Long Term Debt	114,467	7.231%	5.000%	(2,554)
2008 Unfunded Debt Increase	1,719		5.000%	86
2008 Long Term Debt Increase	18,297		7.231%	1,323
				2,327

The planned refinancing of Long-Term Debt with Unfunded Debt simply aligns the 2007 Approved debt component mix with that of 2008 Forecast.

The 2008 forecast unfunded interest rate used in the revenue requirement was based upon the overnight rate forecast from RBC Capital Markets Financial Market Forecasts dated October 2007 and the Conference Board of Canada prime interest rate forecast included in The Canadian Outlook Executive Summary Autumn 2007, Table 1 - Key Economic Indicators, forecast dated September 18, 2007, (included in Attachment 2.2).

Based upon these 2 forecasts the prime rate is expected to remain at or near the current level of 6.25% throughout 2008. Since short-term debt costs the Company on average 1.3% lower than prime, the forecast 2008 short-term interest rate was determined to be 4.95% which was rounded to the nearest quarter percent of 5.00% for rate setting purposes.

The following issues will mature in 2008:

- 2005 Long-Term Debt – Coastal Facilities; January 1, 2008 - $50.3 million
- Medium Term Note – Series 9 – June 2, 2008 $55.0 million
- Medium Term Note – Series 9 Re-opened – June 2, 2008 $58.0 million
- Medium Term Note – Series 9 Re-opened – June 2, 2008 $75. million

The Coastal Facilities swap is forecast to be refinanced through Unfunded Debt. A $200 million 30 year debt issue with a forecast rate of 5.95% in planned for June 1, 2008. The 5.95% is a forecast rate only and Terasen Gas will advise the Commission of the amount and terms of the actual issuance of the long-term debt in accordance with Commission Order No. G-137-05

In the event there is a variance between forecast and actual with respect to the interest rate of long-term debt principal or timing of debt issue, the variance will be recorded in an interest deferral account and recovered or returned to customers in future periods.

2.3 Please provide an updated interest rate forecast as of October 15, 2007.

Response:

As of October 15, 2007 there is no change to the interest rate forecasts provided.

2.4 Please segment $4.2 million the Customer Growth and Use Rate impact into Customer Growth and Use Rate components.

Response:

See response to BCUC IR No. 1, Question 1.1.

2.5 Please explain the change in Pension and Insurance Forecast of $3.4 million.

Response:

The change of $3.4 million accounts for the difference between 2007 approved and 2008 forecast Pension and Insurance Variance, as presented in Section A-5, page 3, line 14, column 13 less column 16.

The Pension and Insurance Variance represents the difference between formula and forecast Cost of Service Based Pension and Insurance expense. The $3.4 million can be attributed to a net decrease of $2.8 million in the actuarial pension forecast between 2007 and 2008, a net decrease of $0.4 million forecast in Insurance expense and $0.2 million associated with the adjusted formula base between 2007 and 2008

2.5.1 Why is there a Pension variance of -$2.235 million in 2007 and -$5.117 million in 2008 (Section A-5, p. 3)?

Response:

This variance represents the difference between Formula and forecast Cost of Service Based Pension expense. A variance exists because the actuarial pension forecast is lower than the pension expense derived by the formula calculation of O&M in 2007 and 2008. The performance of the TGI Pension Plans has been such that actuarial based pension expense calculations have dropped significantly in 2007 and 2008.

2.5.2 Why is there a Insurance variance of $1.040 million in 2007 and $0.542 million in 2008 (Section A-5, p. 3)?

Response:

This variance represents the difference between Formula and Cost of Service Based Insurance expense. A variance exists because the Cost of Service based forecast is higher than the insurance expense derived by the Formula. The 2007 variance of $1.040 million is $0.124 million less than the 2006 variance showing that while the 2007 Formula increased with CPI and Customer Growth, the Cost of Service based forecast showed a marginal decrease. The 2008 variance of $0.542 million is $0.498 million less than the 2007 variance showing that while the 2007 Formula increased by $0.081 million, the Cost of Service Based forecast decreased by $0.417 million.

3.0 Reference: Exhibit B-1, Section A-2, 2008 Cost Drivers

3.1 Why is the BMO Capital Markets Provincial Monitor Summer 2007 included in the filing? Is any figure on this page used in the Annual Review? If so, please elaborate.

Response:

The BMO Capital Markets Provincial Monitor Summer 2007 was included in the Advanced Materials filing for information purposes only and is not used in the Annual Review. However this publication does support a higher CPI forecast for 2008.

4.0 Reference: Exhibit B-1, Section A-3, Plant Additions, pp. 3, 9 and 9.1

"The software tax savings are based on the software plant additions arising from the base capital additions formula. 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. CIAOC is subject to the same adjustment and true-up process as base capital additions.

Therefore, the CIAOC additions for 2008 have been adjusted based on projected 2007 customer counts."

4.1 Please show the calculation of the Projected 2007 and Forecast 2008 for Software Tax Savings, Service Line Installation Fee and Other CIAOC additions in Exhibit B-1, Section A-3, pages 9 – 9.1. Use the same format as the Capital Expenditure schedule on Section A-3, page 5.

Response:

TERASEN GAS INC.
SOFTWARE TAX SAVINGS, SERVICE LINE INSTALLATION FEE AND OTHER
FOR THE YEARS ENDING DECEMBER 31, 2007 and 2008

Particulars	Projected 2007	Forecast 2008
(1)	(2)	(3)
Forecast CPI (BC)	2.00%	2.10%
Adjustment Factor	1.32%	1.39%
CPI - Adjustment Factor	100.68%	100.71%
SOFTWARE TAX SAVINGS		
Non-Infrastructure Software Expenditures Per Customer	$3.11	$3.14
Average Number of Customers	817,480	829,970
Total Non-Infrastructure Software Additions Current Year	$2,545	$2,607
Two Year Average Non-Infrastructure Software Additions	$2,436	$2,576
Tax Rate	34.12%	32.5%
Total Non-Infrastructure Additions to Software Tax Savings ($000)	**$831**	**$837**
Infrastructure Software Expenditures Per Customer	$7.88	$7.95
Average Number of Customers	817,480	829,970
Total Infrastructure Software Additions Current Year	$6,442	$6,598
Two Year Average Infrastructure Software Additions	$6,161	$6,520
Tax Rate	34.12%	32.5%
Total Infrastructure Additions to Software Tax Savings ($000)	**$2,102**	**$2,119**
Total Additions to Software Tax Savings ($000)	**$2,933**	**$2,956**
SERVICE LINE INSTALLATION FEE		
Service Line Installation Fee Per Customer Addition	$215.00	$215.00
Customer Addition	13,129	11,797
Total Service Line Installation Fee Additions ($000)	**$2,823**	**$2,536**
OTHER		
Excess Service Line Changes Per Customer Addition	$77.60	$78.16
Main Extension Per Customer Addition	$29.61	$29.83
Customer Addition	13,129	11,797
	$1,408	$1,274
Billable Alterations Per Total Customer	$0.74	$0.74
Other Per Total Customer	$1.37	$1.38
Total Customer	825,812	837,609
	$1,743	$1,780
Total Other Additions ($000)	**$3,150**	**$3,054**

5.0 Reference: Exhibit B-1, Section A-3, Rate Base, p. 4

Page 4 states: "If the Commission does approve the elimination of the $215 charge as well as adjusting the Service Line Allowance TGI proposes to defer the value of the cost of service associated with the changes by crediting a deferral account and amortizing it in the following year. TGI requests Commission approval to create a deferral account in the event there are changes to the SLIF and SLCA."

5.1 If there are changes to the SLIF and SLCA what would be the impact to the 2008 revenue requirements and the deferral addition amount? State the assumptions.

Response:

This question is essentially the same as BCOAPO IR No. 1 (Exhibit B-5) from the System Extension and Customer Connection Policy application, Question 3.2. A summary of the response is provided below:

At this time the Company can not predict the number of new attachments that will result from the proposed changes to the SLIF and SLCA. However, the Company believes that these changes along with continued marketing efforts, changes to the BC Hydro Rate Design connection policies, and changes to energy efficiency and attachment policies will result in an increase in customer additions.

Hypothetically, revenue requirements 2008 through 2010 are as follows if the changes to the SLIF and SLCA are approved:

TGI

Incremental Revenue Requirement	**2008**	**2009**	**2010**
Return on Rate Base	$134,039	$395,643	$646,402
Depreciation	0	80,808	159,507
Tax	(9,373)	11,777	33,280
Incremental Revenue Requirement	$124,666	$488,228	$839,189

Additions to a deferral account for the incremental cost of service would depend on when changes to the SLIF and SLCA went into effect. A full year has been reflected in the response with no additional incremental customer additions due to the change in the policy.

Please refer to the responses to BCUC IR No. 1 (Exhibit B-3) in the Application for System Extension & Customer Connection Changes Review; Questions 2.5, 2.6, 29.1 and 29.2 as well.

Details of the calculations including assumptions can be found in Table 5.1.

Table 5.1

Incremental Rate Base	**2008**	**2009**	**2010**
GPIS Opening	$0	$3,640,000	$7,185,000
Plant Additions	3,640,000	3,545,000	3,505,000
GPIS Closing	3,640,000	7,185,000	10,690,000
Plant Accumulated Depreciation	0	(80,808)	(240,315)
Plant Closing	3,640,000	7,104,192	10,449,685
Mid Year Plant Adjustment	(1,820,000)	(1,772,500)	(1,752,500)
Mid Year Accumulated Depreciation Adjustment	0	40,404	79,754
Mid Year Incremental Rate Base	**$1,820,000**	**$5,372,096**	**$8,776,939**
Opening Accumulated Depreciation	$0	$0	$80,808
Depreciation Expense	-	80,808	159,507
Closing Accumulated Depreciation	0	80,808	240,315
Mid Year Accumulated Depreciation	0	40,404	160,562
Mid Year Accumulated Depreciation Adjustment	$0	$40,404	$79,754
Return on Base			
Debt Interest	$80,707	$238,223	$389,208
Equity Return	53,332	157,421	257,194
Total	$134,039	$395,643	$646,402
CCA			
Opening	$0	$3,567,200	$6,898,612
Additions	3,640,000	3,545,000	3,505,000
CCA Full Year	0	(142,688)	(275,944)
CCA @ 1/2 year	(72,800)	(70,900)	(70,100)
Closing	$3,567,200	$6,898,612	$10,057,568
Tax			
Equity Return	$53,332	$157,421	$257,194
Add: Depreciation	0	80,808	159,507
Less: CCA	(72,800)	(213,588)	(346,044)
Taxable Income After Tax	($19,468)	$24,641	$70,656
Gross up to Before Tax (1-Tax Rate)	($28,841)	$36,236	$102,401
Income Tax	($9,373)	$11,777	$33,280

Assumptions	**2008**	**2009**	**2010**
Total SLIF Change (Rounded)	$ 2,535,000	$ 2,440,000	$ 2,400,000
Total SLCA Change (Rounded)	$ 1,105,000	$ 1,105,000	$ 1,105,000
Tax Rate	32.50%	32.00%	31.00%
CCA Class 1	4.00%	4.00%	4.00%
Depreciation Rate	2.22%	2.22%	2.22%

Capital Structure	Cost	Capital Structure	
Short-term Debt	4.75%	5.58%	*
Long-term Debt	7.02%	59.41%	*
Equity	8.37%	35.01%	*
		100.00%	

**Same for all three years based on 2007 Revenue Requirment Application*

For TGI Rate impacts would be approximately as follows:

Incremetal Revenue Requirement	$124,666	$488,228	$839,189
Total Sales Volumes (based on 2006 volumes)	112,775,000	112,775,000	112,775,000
Increase per GJ	$ 0.001	$ 0.004	$ 0.007

6.0 Reference: Exhibit B-1, Section A-3, p. 6 and Section A-5, p. 2

Forecast 2008 Base Capital Additions

6.1 Please show the calculation of the Forecast F2008 AFUDC of $0.994 million.

Response:

AFUDC is calculated on all projects greater than $50,000 and over 3 months in duration. As a result not all spending has AFUDC calculated on it. Below is the weighted average of AFUDC calculated per dollar spent.

BCUC Account	Capital Additions	AFUDC	Weighted Average
Intangible Plant	$0	$0	0%
Manufactured Gas/Local Storage	$451	$18	3.99%
Transmission Plant	$8,858	$205	2.3%
Distribution Plant	$69,531	$493	0.71%
General Plant	$20,853	$278	1.33%
TOTAL GAS PLANT IN SERVICE	**$99,693**	**$994**	**1.0%**

6.2 Please explain why the Forecast 2008 Overhead Capitalized of $27.535 million on Section A-3, page 6 is not consistent with the $27.552 million of overheads capitalized on Application, Section A-5, page 2. Please review and revise if necessary.

Response:

The amount included in Section A-5, page 2 of the Application of $27.552 million is the correct amount. Regrettably, page 6 of Section A-3 was a stale version of that particular page and was filed in error. A revised page 6 has been filed with the November 2, 2007 Revised Annual Review Filing, which includes overheads capitalized of $27.552 million.

7.0 Reference: Exhibit B-1, Section A-3, Rate Base, p. 6

7.1 On page 6, line 51, column 3 for Adjusted 2007 it has $1.805 million for the line titled "Insert Line for Acc Deprn From pg 15 (Excluding Intangibles)". What is the nature of this adjustment? Please provide the referenced page 15 regarding the $1.805 million.

Response:

Page 6 of Section A-3, line 51 appears in error; however, the total of $139.551 million on line 55 was correct and did not include the amount on line 51. A revised Schedule A-3, Page 6 which corrects this error has been included in the November 2, 2007 Revised Annual Review Filing.

8.0 Reference: Exhibit B-1, Section A-3, 2007 Approved Utility Rate Base, p. 7

8.1 Please explain why the 2007 Approved Accumulated Depreciation of $744.297 million on Section A-3, page 7 is not consistent with the $744.227 million on the 2007 Revised Rates -Accumulated Depreciation on 2006 Annual Review, Section A-3, page 7. Please review and revise if necessary.

Response:

Subsequent to the October 5 filing and per Order No. G-160-06, the depreciation rate on the Squamish unamortized conversion expense was amended to 10 years.

8.2 Please explain why the 2007 Unamortized Deferred Charges of $8.222 million on Section A-3, page 7 is not consistent with the $8.227 million on 2007 Revised Rates - Unamortized Deferred Charges on 2006 Annual Review, Section A-3, page 7. Please review and revise if necessary.

Response:

Section A-3, page 7 reflects a revised balance of $8.222 million associated with 2007 Unamortized Deferred Charges. The balance is not consistent with Unamortized Deferred Charges as filed with the 2006 Advanced Materials because of an update that was made to the 2007 gross additions associated with the TGS O&M Variance account that was subsequent to the 2006 Advanced Materials filing but part of the 2006 Settlement. (Reference Exhibit B-5, 2006 Annual Review and Mid-Term Assessment Review, Response to BCUC No. 1, Question 8.3, p. 11) Thus no revision is necessary.

8.3 Please explain the $0.647 million increase in Construction Advances from 2007 Approved to 2008 Revised Rates.

Response:

Mid-year Construction Advances are utilized in the calculation of Rate Base. Increases in Construction Advances result in decreases to Rate Base. The increase to Construction Advances in 2008 reflects the increase in billable alterations to infrastructure that are being forecast in 2008. Billable alterations are third party requests to alter the Transmission or Distribution infrastructure of TGI. The cost of the alteration is added to rate base as a system improvement, while the offsetting customer contribution, which is recorded in the Customer Advances account, is deducted from rate base. TGI manages billable alterations in a fashion that minimizes or eliminates rate base impact.

8.4 Please explain the $1.413 million increase in Work in Progress, No AFUDC from 2007 Approved to 2008 Revised Rates.

Response:

The $1.413 million change in Work in Progress, No AFUDC between 2007 Approved and 2008 Forecast is a decrease as opposed to an increase to Rate Base and Rates. In relation to 2007, this means that a higher percentage of 2008 Formula Capital Expenditures are being put in service, while a smaller percentage is remaining in Work In Progress. Given that Plant Additions in Service and Work In Progress No AFUDC both are added to Rate Base via a mid year calculation, this variance has no net impact on Rate Base and Rates.

9.0 Reference: Exhibit B-1, Section A-3, Rate Base, p. 7

Section A-3, page 7, line 32 includes a LILO Benefit of $2.243 million for Approved 2007 and $1.980 million for 2008.

9.1 Why is the benefit lower in 2008? Show the computations for 2008.

Response:

The LILO Benefit on Section A-3, page 7 line 32 captures benefit to customers of Terasen Gas LILO Agreements. These benefits are amortized on a straight line basis over the life of each LILO. As there have been no new LILO Agreements, and thus no additions to LILO Benefits, the annual decline in this amount represents the annual amortization.

10.0 Reference: Exhibit B-1, Section A-3, Rate Base, pp. 8 to 8.1

10.1 Please file a comparison with differences for the Forecast 2007 Additions and the Actual 2007 Additions shown on pages 8 and 8.1.

Response:

The 2007 Approved Additions from the 2006 Annual Review are based on 2005 Actual and 2006 Forecast customer counts. The 2007 Additions from page 8 and 8.1 are based on the 2006 Actual and 2007 Forecast customer counts. The result is that the 2007 Additions on page 8 and 8.1 have been trued up for 2006 Actual Customer Count.

Line No.		2007 Approved Total Additions (including CPCN)	2007 Projected Total Additions (including CPCN)	Difference
		(1)	(2)	(1)-(2)
1	**INTANGIBLE PLANT**			
	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -
	175-00 Unamortized Conversion Expense	-	-	-
	175-00 Unamortized Conversion Expense - Squamish	-	-	-
	178-00 Organization Expense	-	-	-
	179-01 Other Deferred Charges	-	-	-
2	401-00 Franchise and Consents	-	-	-
3	402-00 Utility Plant Acquisition Adjustment	-	-	-
4	402-00 Other Intangible Plant	-	-	-
5	TOTAL INTANGIBLE PLANT	$ -	$ -	$ -
6				
7	**MANUFACTURED GAS / LOCAL STORAGE**			
8	430 Manufact'd Gas - Land	$ -	$ -	$ -
9	432 Manufact'd Gas - Struct. & Improvements	-	-	-
10	433 Manufact'd Gas - Equipment	-	-	-
11	434 Manufact'd Gas - Gas Holders	-	-	-
12	436 Manufact'd Gas - Compressor Equipment	-	-	-
13	437 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-
14	440/441 Land in Fee Simple and Land Rights	-	-	-
15	442 Structures & Improvements	-	-	-
16	443 Gas Holders - Storage	611	640	(29)
17	446 Compressor Equipment	-	-	-
18	447 Measuring & Regulating Equipment	-	-	-
19	448 Purification Equipment	-	-	-
20	449 Local Storage Equipment	-	-	-
21	TOTAL MANUFACTURED GAS / LOCAL STORAGE	$ 611	$ 640	$ (29)
22				
23	**TRANSMISSION PLANT**			
24	460-00 Land in Fee Simple	$ -	$ -	$ -
25	461-00 Land Rights	1,360	1,356	4
26	461-10 Land Rights - Byron Creek	-	-	-
27	462-00 Compressor Structures	418	437	(19)
28	463-00 Measuring Structures	-	-	-
29	464-00 Other Structures & Improvements	-	-	-
30	465-00 Mains	3,331	3,176	155
31	465-10 Mains - Byron Creek	-	-	-
32	466-00 Compressor Equipment	50	15	35
33	467-00 Measuring & Regulating Equipment	5,551	5,806	(255)
34	467-10 Telemetering	-	-	-
35	467-20 Measuring & Regulating Equipment - Byron Creek	-	-	-
36	468-00 Communication Structures & Equipment	712	744	(32)
37	469-00 Other Transmission Equipment	-	-	-
38	TOTAL TRANSMISSION PLANT	$ 11,422	$ 11,534	$ (112)

TERASEN GAS INC.

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000s)

Line No.		2007 Approved Total Additions (including CPCN)	2007 Projected Total Additions (including CPCN)	Difference
1	**DISTRIBUTION PLANT**			
2	470-00 Land in Fee Simple	$ -	$ -	$ -
3	471-00 Land Rights	125	125	-
4	471-10 Land Rights - Byron Creek	-	-	-
5	472-00 Structures & Improvements	617	664	(47)
6	472-10 Structures & Improvements - Byron Creek	-	-	-
7	473-00 Services	27,764	31,266	(3,502)
8	474-00 House Regulators & Meter Installations	10,207	10,620	(413)
9	475-00 Mains	38,911	40,470	(1,559)
10	476-00 Compressor Equipment	-	-	-
11	477-00 Measuring & Regulating Equipment	10,577	10,852	(275)
12	477-00 Telemetering	-	183	(183)
13	477-10 Measuring & Regulating Equipment - Byron Creek	-	-	-
14	478-00 Meters	16,656	12,357	4,299
15	479-00 Other Distribution Equipment	26	26	-
16	TOTAL DISTRIBUTION PLANT	$ 104,883	$ 106,563	$ (1,680)
17				
18	**GENERAL PLANT & EQUIPMENT**			
19	480-00 Land in Fee Simple	$ 34	$ 22	$ 12
20	481-00 Land Rights	-	-	-
21	482-00 Structures & Improvements	-	-	-
22	- Frame Buildings	-	-	-
23	- Masonry Buildings	693	-	693
24	- Leasehold Improvement	-	664	(664)
25	483-00 Office Furniture and Equipment	-	-	-
26	- Furniture & Equipment	519	512	7
27	- Computer Hardware	6,942	6,921	21
28	- Computer Software (Infrastructure)	6,456	6,458	(2)
29	- Computer Software (Non-Infrastructure)	2,553	2,545	8
30	484-00 Transportation Equipment	187	158	29
31	485-00 Heavy Work Equipment	-	-	-
32	486-00 Small Tools & Equipment	2,393	2,382	11
33	487-00 Equipment on Customer's Premises	-	-	-
34	- VRA Compressor Installation Costs	-	-	-
35	488-00 Communications Equipment	1,158	-	1,158
36	- Telephone	-	587	(587)
37	- Radio	-	564	(564)
38	489-00 Other General Equipment	2	-	2
39	TOTAL GENERAL PLANT	$ 20,937	$ 20,813	$ 124
40				
41	**UNCLASSIFIED PLANT**			
42	499 Plant Suspense	-	-	-
43	TOTAL UNCLASSIFIED PLANT	-	-	-
44				-
45	**TOTAL CAPITAL**	**$ 137,853**	**$ 139,550**	**$ (1,697)**

10.2 On page 8.1 please explain the 2007 retirements for Services (line 7), Mains (line 9), and Computer Hardware/Software (lines 27 to 29).

Response:

Services and Mains:

BCUC Account	Additions	Retirement	Rate (note1)
Services	$26,213	$3,932	15%
Mains	$35,696	$3,570	10%

Note 1 – TGI calculates retirements based on a percentage of additions. The percentage rate used is based on historical practice.

Hardware

Hardware is retired when the NBV of the asset reaches zero. Hardware of $8,750 will reach a NBV of zero at December 31, 2007. These assets, which went into service on Jan 1, 2003, include such items as: Gas Day Infrastructure hardware, Portfolio Management & Decision Support hardware and SAP upgrade hardware.

Software (infrastructure and non-infrastructure)

Software is retired when the NBV of the asset reaches zero. Software Infrastructure of $7,624 will reach a NBV of zero at December 31, 2007. These assets went into service on Jan 1, 2000. Software Non-Infrastructure of $7,208 will reach a NBV of zero at December 31, 2007. These assets went into service on Jan 1, 2003. These retirements includes such items as: WMS/AMFM/MICS, AM/FM Software, Automated Mapping System, Coastal Map upgrade, Distribution construction records system and Gas Decision Support System.

11.0 Reference: Exhibit B-1, Section A-3, Rate Base, p. 12

TGI states in regard to the Lochburn land sale approved by Commission Order G-116-07: "At this time the sale of the land has not been completed. While TGI is hopeful the completion of the sale of land will occur in 2007 it is uncertain if all required conditions can be met before year end. The materials in the annual review do not reflect the sale of the land. TGI proposes that the value of the cost of service from the sale of land would be credited to a deferral account and amortized in the following year reducing the amortization expense from what it would otherwise be. The cost of service reduction would be based on the reduced operating and maintenance expense, property tax and the mid-year rate base effect on earned return and income tax expense using the approved capital structure and allowed return on capital for 2008."

11.1 From the approval date of September 21, 2007 to the final closing of the sale, please elaborate on the steps and timeline needed to complete the sale of the land.

<u>Response:</u>

As part of the Offer to Purchase, Terasen Gas is responsible to satisfy three true precedent conditions: Certificate of Compliance, subdivision of the property and servicing agreement for the surplus land. Estimated timelines to complete the three conditions are as follows:

1. Certificate of Compliance

- Remediation – September 30, 2007;
- Remediation and Risk Assessment Reporting – September 30 – October 31, 2007;
- Review by Environmental Panel Expert – November 1 – November 30, 2007; and
- Ministry of Environment Approval and Issue of Certificate of Compliance – December 1 – 21, 2007.

2. Subdivision of Properties

- Completion of servicing drawings – October 31, 2007;
- City of Burnaby Review and Approval – October 31 – November 30, 2007; and
- Covenant Agreement – November 7, 2007.

3. Servicing Agreement

- Agreement with the City of Burnaby in dealing with installation of on and off site servicing as approved by drawings – November 30, 2007 – December 15, 2007.

In addition, we must seek and obtain bondholder consent to obtain a discharge on the Purchase Money Mortgage financing secured by the property. This is expected between December 1 and 15, 2007.

11.2 What are the remaining issues outstanding to complete the land sale at Lochburn?

Response:

TGI has an obligation to deliver title to the subdivided site in registerable form in order to complete the land sale at Lochburn. To achieve this, TGI has to meet various requirements as outlined by the City of Burnaby in Subdivision Application #04-05. Also, TGI must demonstrate that the site complies with the Ministry of Environment guidelines according to the Waste Management Act and Contaminated Site Regulations. There will be no obligation or liabilities after the closing date.

11.3 TGI requested an expedited process to review the Lochburn land sale. Why was an expedited decision required if TGI may not be able to close the land sale by the end of 2007?

Response:

The expedited process was requested to allow Terasen to fulfill its seller's condition of providing approval by Utilities Commission by September 26, 2007.

11.4 Please prepare a detailed schedule of the 2008 impact on the cost of service and revenue requirements if TGI assumed that the sale was completed by the end of 2007.

Response:

The 2008 cost of service impact and revenue requirements decrease in 2008 assuming the sale was completed by the end of 2007 would be approximately $221,946 calculated as follows:

Year	2008
Incremental Rate Base	
Land and Land Rights Mid Year	$1,136,155
Capital Structure	
Equity Portion	35.01%
Debt Portion	64.99%
Financed by Equity	$397,768
Financed by Debt	$738,387
Financing	
Allowed ROE	8.37%
Effective Debt Rate	6.61%
Equity Return	$33,293
Debt Interest	$48,793
Tax Calculation	
Income Tax Rate	32.50%
Gross up %	67.50%
Equity Return Before Tax	$49,323
Income Tax	$16,030
Property Taxes	
Property Tax on Sale Portion	$122,330
Approx. Maintenance Costs and Other	$1,500
Total Carrying and Maintenance Costs	
Equity Return	$33,293
Interest	48,793
Income Tax	16,030
Property Tax	122,330
Approx. Maintenance Cost and Other	1,500
Total Cost of Service Reduction	**$221,946**

11.4.1 Would it be appropriate to include the approved sale in the 2008 Forecast and set up a deferral account to capture any variances if the sale was not completed before the end of 2007? Explain.

Response:

Setting up a deferral account to capture any variances if the sale was not completed before the end of 2007 would achieve the same result.

12.0 Reference: Exhibit B-1, Section A-3, Rate Base, p. 13

12.1 Pages 13.2 and 13.3 of Section A-3 Rate Base in column 3 states "Forecast Balance 12/31/2006" for the Unamortized Deferred Charges and Amortization schedule. Should this be Actual Balance instead of Forecast Balance?

Response:

Yes, this amount should be Actual Balance instead of Forecast Balance.

12.2 Please file the Actual 2006 continuity schedule for Unamortized Deferred Charges and Amortization.

Response:

Please refer to Attachment 12.2.

12.3 What is the projected gross addition for NGV Grants in 2007? Is this similar to the $70,000 Forecast for 2008?

Response:

The projected gross addition for NGV Grants in 2007 is $70,000 which is identical to the 2008 Forecast. Reference Exhibit B-1, Section A-3, Rate Base, p. 13.2, line 4, column 4.

12.4 The 2006 Annual Report to the Commission on page 38 identifies NGV Gas Plant in Service (Mid-Year) of $962,000.

12.4.1 In the 2008 plant schedules what is the 2008 Forecast balance? Please provide a schedule with account codes and descriptive names that show the gross and accumulated NGV plant.

Response:

The schedule below shows the ending 2006 NGV balances and the forecast for 2007 and 2008:

		12/31/06	12/31/2007	12/31/2008
Cost:				
48720	Equipment on Customers' Premises	1,839,000	1,839,000	1,839,000
47600	Compressor Equipment - Other	571,000	571,000	571,000
		2,410,000	2,410,000	2,410,000
Accum Dep'n				
48720	Equipment on Customers' Premises	1,214,104	1,306,054	1,398,004
47600	Compressor Equipment - Other	289,000	327,086	365,171
		1,503,104	1,633,140	1,763,175
Net book value		906,896	776,860	646,825

12.4.2 Has TGI performed an audit to confirm that the assets are accounted for as booked in the general ledger? If yes, what were the results?

Response:

TGI has not performed an audit specifically on the NGV assets. An audit of TGI's financial statements is undertaken annually. The scope of that audit includes all material financial statement items, but no specific request has been made to undertake an audit of the NGV assets.

12.5 What were the actual 2006 gross additions for the SCP Net Mitigation Revenues (page 13.1 line 14). Show the derivation.

Response:

SCP Revenues	85,901
SCP Purchases	79,651
Net Mitigation (differential)	6,250
Forecast	1,000
Gross Additions	5,250

12.5.1 Please show how the SCP Net Mitigation Revenues for 2008 were calculated.

Response:

In the Filing (Exhibit B-1, Tab A-4, Page 8, Section 8), SCP revenues for Northwest Natural Gas Co. were misstated. The revised table following shows the corrected SCP Net Mitigation Revenues for 2008, comprised of the four components:

2008 SCP Revenues

Northwest Natural Gas Co.	$	7,277,094
PG&E Termination	$	(825,000)
MCRA	$	3,600,000
Net Mitigation	$	1,000,000
Total SCP Revenues	**$**	**11,052,094**

The demand charge of $7,277,094 from Northwest Natural Gas Co. is based on Tariff Supplement No.1-6 approved by the Commission in Order No. G-53-05. The Northwest Natural Gas Company's firm transportation service on the SCP has a specific transportation rate in Exhibit A – Demand Charge Determination from November 1, 2004 to October 31, 2010. The payment of $825,000 to PG&E is also based on a contractual agreement resulting from the termination of a prior PG&E contract on SCP. The PG&E termination payments were approved by the Commission in Order No. G-98-05. TGI recovers $3,600,000 from the MCRA as directed by the Commission in Order No.G-98-05 as result of the termination of the BC Hydro TSA on SCP. Finally, $1,000,000 worth of revenue is forecast from third parties for the movement of gas across SCP during periods when it is economical to do so. This one million dollar forecast is consistent with that forecast in past years.

12.6 Please confirm that TGI has suspended further expenditures on the Depreciation and Overheads Capitalized Studies as directed by Commission Order No. G-160-06. Please quantify the amount spent prior to the suspension and where it is recorded.

Response:

Subsequent to Order G-160-06, TGI suspended all further expenditure on the Depreciation and Overheads Capitalized studies. Prior to the suspension, TGI had incurred a total expense of $57,246 pre-tax ($38,355 net of tax) which has been charged to Future Revenue Requirements Deferral Account 18160.

12.7 When was the last time TGI conducted a comprehensive inventory and property, plant and equipment audit to verify the plant assets to the plant sub-ledger? How many of these audits have been completed in the last 10 years?

Response:

There have been no special purpose audits of the inventory and property, plant and equipment records in the last 10 years. The Asset Accounting department is charged with the responsibility of recording additions and retirements in a timely fashion and to the correct asset class, in accordance with established policies, and reconciling plant accounts in the general ledger. The financial statement audits assess the net asset values each year in order to provide an audit opinion as to the fair presentation of the financial position of the Company.

12.8 Does TGI have a robust plant inventory system to perform actuarial data analysis for a depreciation study rather than relying on simulated plant records? Please elaborate.

Response:

The asset sub-ledger has the asset acquisitions and retirements recorded by year, providing the ability to analyze the data and prepare detailed depreciation studies.

12.9 Does TGI have any surplus property, plant or equipment including land? If so, please identify these assets.

Response:

Other than the Lochburn land, all land and buildings in rate base are being used for utility services or for the benefit of utility customers through rental recoveries on space that has been sublet. There may be some general plant items that are included in rate base and are no longer used and useful, but have not yet been retired under the general plant method, since their net book value has not yet reached zero. However, the reverse is also true, there are items that have been fully depreciated and retired under the general plant method which are still in use but are not costing customers anything.

13.0 Reference: Exhibit B-1, Section A-3, Rate Base, pp. 15 to 15.2

13.1 Please reconcile the $765,334 Forecast 2008 Depreciation and Amortization balance on Section A-3, page 15 to the $811,512 December 31, 2008, balance on Section A-3, page 15.2.

Response:

December 31, 2008 balance on Section A-3, Page15.2	$811,512
CIAOC Amortization Balance, Beginning – Section A-3, Page 15, Line 3	(41,088)
2008 Amortization of CIAOC – Section A-3, Page 15, Line 18	(6,482)
2008 CIACO Retirements – Section A-3, Page 15, Line 24	1,392
December 31, 2008 balance on Section A-3, Page 15	$765,334

14.0 Reference: Exhibit B-1, Section A-3, Proceeds on Disposal, p. 15.2

14.1 In 2008, TGI forecasts $1.241 million of Furniture & Equipment and $0.753 million of Computer Hardware retirements. Please explain why there are no Proceeds on Disposal associated with these retirements.

Response:

This is a general plant retirement; therefore we are retiring these assets when the NBV reaches zero. This is not an actual sale so there would not be proceeds.

14.2 Please explain the steps and review process that TGI uses in ensuring that retirements for each itemized plant retirement unit is retired when it should be. When was the last time this policy was reviewed?

Response:

There are different procedures depending on the type of plant being retired:

- For Distribution mains and services, Asset Accounting reviews all of the abandonment service orders that are produced throughout the year as field crews complete orders, and retires the length of pipe based on vintage year and average unit cost.
- General Plant is retired when NBV reaches zero.
- For Meters, Asset Accounting runs a report out of SAP that identifies the meters that have been scrapped or sold. The meters and corresponding installation costs are retired by vintage year and average unit cost.
- For other items, once a project is complete and in-service, the project managers review the project by filling out a completion checklist. One of the items on the checklist is if any of these assets were abandoned and therefore need to be retired. The project manager sends the applicable Plant Retirement Request (PR) to Asset Accounting to retire the applicable assets.

Plant retirement policies are reviewed when circumstances indicate the need for updates. The plant retirement catalogue is currently under review.

15.0 Reference: Exhibit B-1, Section A-4, p. 6

TGI and TGVI Application for System Extension & Customer Connection Changes Review, Exhibit B-9, BCUC IR No. 2, BCUC IR 40.5

"Lower projected consumption for 2008 - with respect to 2007 - primarily reflects the impact of colder than normal weather experienced over the first six months of this year and declining residential use rates."

15.1 For TGI Rate 1, please update the median, mean and histogram in BCUC IR 40.5 for the period September 1, 2006 to August 31, 2007.

Response:

TGI is currently experiencing difficulties with the billing data required to complete this request. Efforts are underway to resolve this issue and the response to this question will be provided as soon as the necessary data becomes available.

16.0 Reference: Exhibit B-1, Section A-4, p. 9

Miscellaneous Revenue from NRBs

"Other miscellaneous revenue is estimated at approximately $59,000 comprising of Non-Regulated Businesses (NRB) recoveries."

16.1 Please provide a breakdown of the $59,000 NRB recoveries by type of work performed and by NRB.

<u>Response:</u>

The Miscellaneous Revenue from NRB recoveries consists of the general overhead and facilities charges per the transfer pricing policy on the Specific Committed Service contracts planned for 2008.

<u>2008 Miscellaneous Revenue from Non-Regulated Businesses (NRB) Recoveries</u>

By NRB

Terasen Inc.	30,146
Terasen Energy Services Inc.	13,748
Inland Energy Corp.	613
Terasen Huntington Inc.	14,252
	58,758

By Function

President TGI	3,678
Distribution	4,234
Marketing	18,875
Business Services	4,067
Gas Supply & Transmission	2,861
Finance & Regulatory Affairs	16,064
Operations Governance	8,979
	58,758

17.0 Reference: Exhibit B-1, Section A-5, O&M Expense, p. 2

Page 2, line 19 includes a deduction of $1.652 million for DRIA to calculate capitalized overhead.

17.1 What is DRIA? Please segment the DRIA into its component amounts. Please provide a detail of DRIA activities and spending that makes up the $1.652 million.

Response:

The acronym DRIA stands for Defined Required Incremental Activity and represents additional funding above the allowed O&M funding as determined by the formula-based approach. The DRIA funding approved by the Commission was initially established as part of the PBR agreement in the late 1990s, primarily for support of Demand Side Management ("DSM") Activities. Recent PBR agreements however no longer distinguish DRIA funding from other O&M funding determined using the formula-based approach. Under the current O&M budgets, there are no expenses that would be classified as DRIA. However, the 2003 Settlement still provides for a notional allowance for DRIA in the calculation of O&M Capitalization

17.2 What has been the actual spending for DRIA by activity/specific program in 2005, 2006, and 2007?

Response:

As specified in the response to Question 17.1, DRIA funding was established primarily for support of DSM Activities. For details of DSM spending in 2005, 2006 and 2007, please refer to the section titled Demand Side Management Status Report in each of TGI's Annual Review filings for 2005, 2006 and 2007. TGI is required to submit an annual DSM status report as part of the Annual Review process.

18.0 Reference: Exhibit B-1, Section A-5, O&M Expense, pp. 5-7

18.1 On page 5, the first column is titled “BCUC No.” Should this be titled “Terasen Gas Operation and Maintenance Code of Accounts” as described in Appendix A?

Response:

That is correct, the first column should be titled “Terasen Gas Operation and Maintenance Code of Accounts.

18.2 The page has a line titled: “Less: Stock Related Compensation” with credits of $1.249 million for Adjusted Base 2007 and $0.313 million for Forecast 2008.

18.2.1 Why is there a deduction for Stock Related Compensation?

Response:

The amounts in Stock Related Compensation actually represent Non-Utility O&M and accordingly should not have appeared on this schedule.

18.2.2 Please identify where these amounts are included the accounts.

Response:

Given that these amounts are Non-Utility, they would not be reflected in the Accounts of the Utility.

18.3 Please provide a comparison of Approved 2007 O&M to Projected 2007 O&M. Include variance by account and subtotals for the two views (account and resource view).

Response:

The requested comparison views are included in Attachment 18.3.

18.4 Section A-5, page 7 includes a line for "Less: Transfer to Manual GL". Please explain the nature of this adjustment and what cost elements are affected by this transfer.

Response:

The amount line for "Less: Transfer to Manual GL" represents the expenses for the Gas Supply department. On a monthly basis these are cleared from O&M and are charged to the MCRA and CCRA accounts through the Recovery and Revenue line. In the revised schedule included in the November 2, 2007 Revised Annual Review Filing, the Company has offset this amount under the Recovery and Revenue line.

18.5 Attachment A-5 includes the New Code of Accounts. Please elaborate on the anticipated changes, if any, to the New Code of Accounts due to future CICA Handbook changes, IFRS changes, and rate-regulated operations.

Response:

Other than the impact as described in Tab B-6 Page 2 Item 2, there are no anticipated changes to the Code of Accounts as a result of announced CICA Handbook changes or rate-regulated operations changes. For the potential of IFRS changes, please refer to the response to Question 25.2.2.

18.6 Please file pages 32 and 33 of the TGI 2006 Annual Report to the Commission.

18.6.1 Please explain the appropriateness of why compensation expensed to Executive Officers increased by $870,000 (37%) in 2006 relative to 2005. Elaborate more on the increase. Is it from base pay, incentives/bonuses, variable pay, etc.?

Response:

The requested pages are included in Attachment 18.6.1.

The change in line item 11 for Executive Offices reflects the accounting expense in the year for base salary, short-term and medium-term retention incentives. In 2005 this line included a credit transfer from 2004 of $489,000 which was applied against the medium term incentive cost resulting in a net expense in the year of $250,000 (Gross of $739,000) the benefit of which expense reduction was shared with customers. After adjusting for this credit to make 2005 comparable with 2006, the total 2005 cost would be $2,842,000 vs. $3,223,000 for 2006.

Therefore the increase in 2006 expense represented a 13% increase over 2005. It reflected the strong operating performance of the company and incentive earnings generated and shared with customers for which all employees including executives were rewarded through their variable pay. It was also in response to the hot labour market and demand for senior managers/executives in the Alberta market place which resulted in a shift in the design of the medium term incentive plan to strengthen retention. Consequently 95 employees representing fully 33% of all management and exempt employees were given three year deferred compensation grants in 2006 which are being amortized over three years. In the case of the executive group this also replaced the former MTIP program which was cancelled in 2006 (see further discussion in Question 18.6.3 below).

Finally, base pay adjustments reflected the elimination of perquisites for executives and the increased responsibilities assumed by them in 2006 following the change of control of the company.

All of which has paid off for customers and stakeholders through effective cost management and increased earnings sharing with customers, maintenance and enhancement of service levels, strengthening of relationships with safety regulators regarding integrity plans and safety practices and improved retention and recruitment results at a time when change and uncertainty related to new ownership could have lead to distraction and complacency resulting in higher costs and lower performance for customers, employees and the public. As such the Company submits the costs are reasonable and effective.

18.6.2 Please explain the appropriateness of the 2006-2009 deferred retention arrangements for executives and senior managers that replaced the previous mid and long term incentive plans. Was this change a result of the purchase by Kinder Morgan, Inc. or Fortis Inc.?

<u>Response:</u>

Please refer to the responses to Questions 18.6.1 and 18.6.3.

18.6.3 Please file further documentation issued by TGI for the deferred retention arrangements, and the mid and long term incentive plans. How is the new plan similar or different both qualitatively and quantitatively from the previous plans?

Response:

Starting in 2006 a new deferred compensation arrangement was put in place which placed emphasis on retaining key employees including senior managers, critical skill employees and executives. This plan provided for lump sum payments on a three year deferral basis where employees had to continue to be employees at maturity date in order to be paid out.

As noted in response to 18.6.1, for executive level employees it replaced the former medium (MTIP) and long-term incentive (LTIP) arrangements in place prior to the acquisition by Kinder Morgan. Historically the MTIP program provided a lump sum payout every third year based on attaining earnings growth targets and the LTIP program was a stock option program. The deferred compensation program initiated following the change of control was established to be reviewed annually and set to provide annual three year deferred compensation grants. Employees had to continue to be employees on the third anniversary of the grant in order to be eligible for payout. The costs of the allotments are amortized over their life pursuant to generally accepted accounting principles similar to the way MTIP costs were amortized.

In the case of non-executive employees this was a new component of their compensation in addition to the employee incentive plan designed to retain hard to replace resources in the face of a buoyant labour market and higher prevailing rates of attrition. It amounted to lump sum payments on a deferred basis of from approximately 5% to 20% of employees base salaries.

In the case of executives it replaced previous medium and long-term programs in place and was designed to keep executives whole with the elimination of previous longer term incentive arrangements as well as provide a long-term retention element. It also reflected the imposition of salary caps and reductions in pension benefits (which are not included in this line item in the annual report) for executives.

19.0 Reference: Exhibit B-1, Section A-6, Taxes and Other Expense, pp. 6 to 9

19.1 Explain the increase in Unfunded Pension from $1.814 million in Approved 2007 to $4.026 million in 2008 (Section A-6, page 6).

19.1.1 Is this change due to more pensionable items, more people eligible for pensions, or an accounting adjustment?

Response:

The descriptor Unfunded Pension should have read "Funded Pension Disallowed for Tax". The amount is calculated by taking the difference between Pension Expense which is not deductible for tax purposes and which is driven by Actuarial valuation, and Contributions made to the Pension Plan which are deductible for tax purposes. The main reason for the increase from $1.814 million in Approved 2007 to $4.026 million in Forecast 2008 is due to a large decrease in the Actuarial valuation for Pension expense for 2008 compared to 2007.

19.1.2 Please file the 2005 and 2006 financial positions of the employee defined benefit pension plans and other benefit plans.

Response:

The following tables provide a summary of the financial positions of the Terasen Gas Inc Management and Exempt and Union plans for 2005 and 2006.

Terasen Gas Inc.
Pension Note disclosure
31 December 2005

	2005 Utility Basic M&E	2005 Utility Supplemental M&E	2005 Utility Union	2005 Total Utility
Accrued benefit obligation:				
Balance beginning of year	45,712	8,372	137,621	191,705
Service cost	621	123	4,325	5,069
Interest cost	2,693	501	8,309	11,503
Benefit payments	(2,907)	(496)	(5,434)	(8,837)
Contributions by members			2,847	2,847
Past service cost		194		194
Special termination benefits				-
Change in discount rate	4,309	1,013	5,322	10,644
Actuarial (gain) /loss including experience gains		535	-	535
Balance at end of year	50,428	10,242	152,990	213,660
Plan assets:				
Fair value at beginning of year	48,759	-	136,457	185,216
Company contributions	991	508	2,816	4,315
Contributions by members			2,847	2,847
Actual return on plan assets	5,528		13,398	18,926
Benefits paid	(2,907)	(496)	(5,434)	(8,837)
Expense load	(62)	(12)		(74)
				-
Balance at end of year	52,309	-	150,084	202,393
Plan surplus (deficiency)	1,881	(10,242)	(2,906)	(11,267)
Unamortized transitional obligation	(4,634)	1,779	(9,387)	(12,242)
Unamortized actuarial (gain) / loss	10,050	1,323	13,349	24,722
Unamortized past service costs	294	1,147	2,170	3,611
Accrued benefit asset (liability)	7,591	(5,993)	3,226	4,824
Reconciliation of Accrued Benefit Asset/(Liability)				
As at December 31, 2004	6,597	(5,540)	3,378	4,435
Transfer to Terasen Inc	-	-	-	-
2005 expense	3	(961)	(2,968)	(3,926)
Transfer to DC plan				
2005 Company contribution	991	508	2,816	4,315
As at December 31, 2005	7,591	(5,993)	3,226	4,824

Terasen Gas Inc. (consolidated)
Table for OPEB disclosure
31 December 2006

	2006 Utility	2006 Union Utility	2006 Total Gas
Accrued post-retirement benefit obligation			
Accrued post-retirement benefit obligation, beginning of year	13,000	51,315	64,315
Current service cost	214	1,003	1,217
Interest cost	642	2,599	3,241
Benefit payments	(414)	(680)	(1,094)
Prior service cost	(169)		(169)
Actuarial losses (gains)	215	505	720
Accrued post-retirement benefit obligation, end of year	13,488	54,742	68,230
Plan Assets			
Plan assets, December 31, 2005	-	-	-
Employer contributions	431	760	1,191
Expense load	(17)	(80)	(97)
Benefit payments	(414)	(680)	(1,094)
Plan assets at December 31, 2006	-	-	-
Plan assets at fair value	-	-	-
Plan surplus (deficiency)	(13,488)	(54,742)	(68,230)
Unamortized new transitional obligation	-	(3,107)	(3,107)
Uamortized past service costs	925		925
Unamortized actuarial loss	(6,936)	(20,721)	(27,657)
Accrued benefit asset (liability)	(7,477)	(30,914)	(38,391)
Reconciliation of accrued benefit asset/(liability)			
As at December 31, 2005	(6,505)	(24,551)	(31,056)
2006 expense	(1,403)	(7,123)	(8,526)
2006 company contribution	431	760	1,191
As at December 31, 2006	(7,477)	(30,914)	(38,391)

Terasen Gas Inc. (consolidated)
Table for OPEB disclosure
31 December 2005

	2005 Utility	2005 Union Utility	2005 Total Gas
Accrued post-retirement benefit obligation	10,843	42,053	52,896
Current service cost	150	798	948
Interest cost	651	2,554	3,205
Benefit payments	(283)	(559)	(842)
Change in discount rate	1,639	6,469	8,108
Actuarial losses (gains)	-	-	-
Accrued post-retirement benefit obligation, end of year	13,000	51,315	64,315
Plan Assets			
Plan assets, December 31, 2004	-	-	-
Employer contributions	295	623	918
Expense load	(12)	(64)	(76)
Benefit payments	(283)	(559)	(842)
Plan assets at December 31, 2005	-	-	-
Plan assets at fair value	-	-	-
Plan surplus (deficiency)	(13,000)	(51,315)	(64,315)
Unamortized new transitional obligation	-	(4,662)	(4,662)
Uamortized past service costs	904		904
Unamortized actuarial loss	(7,399)	(22,102)	(29,501)
Accrued benefit asset (liability)	(6,505)	(24,551)	(31,056)
Reconciliation of accrued benefit asset/(liability)			
As at December 31, 2004	(5,531)	(18,775)	(24,306)
2005 expense	(1,269)	(6,399)	(7,668)
2005 company contribution	295	623	918
As at December 31, 2005	(6,505)	(24,551)	(31,056)
Accrued benefit obligation			
Unfunded plans	13,000	51,315	64,315
Funded palns			-
	13,000	51,315	64,315
Fair value of plan assets	-	-	-
Funded status (deficit)	(13,000)	(51,315)	(64,315)

19.2 On Section A-6, page 9 its shows on line 33 a deduction of a non-rate base item for Squamish Gas Co. Ltd. Please explain this adjustment.

Response:

Page 9 was included in the filing inadvertently. Large Corporations Tax has been repealed for 2007 and 2008 and this Page is no longer relevant.

20.0 Reference: Exhibit B-1, Section A-7, Proceeds on Disposal, p. 2

20.1 Please show the calculation of the Effective Interest Cost for the following long-term debt issues and LILO Obligations:

Description	Issue Date
Medium Term Note - Series 9	21-Oct-1997
Med.Term Note - Series 9 (Re-opened)	19-Nov-1998
Med.Term Note - Series 9 (Re-opening)	21-Sep-1999
LILO Obligations - Kelowna	
LILO Obligations - Nelson	
LILO Obligations – Vernon	

Response:

The Effective Interest Cost is calculated using the Internal Rate of Return ("IRR") methodology for long-term debt issues. It gives recognition to the fact that the actual rate of interest is higher (lower) than the coupon rate due to deducting discounts and issue costs from the proceeds of long-term debt (adding bond issue premiums to the proceeds of long-term debt). The IRR methodology calculates an internal rate of return for a series of cash flows that are made up the net proceeds of the issue offset by the annual interest payments as calculated by the Coupon Rate and the Principal repayment upon maturity of the face value of the issue.

The formula is as follows:

$$\text{NPV} = 0 \quad = \quad \text{Net Proceeds of Issue} \quad + \quad \frac{\text{Interest Payment Year 1}}{(1+\text{IRR})^{1}} + \ldots + \frac{\text{Interest Payment Year n}}{(1+\text{IRR})^{n}}$$

Where "n" = number of years in the life of the Issue

The detail calculations are as follows:

Medium Term Note- Series 9

Issue Date	21-Oct-97	Issue Amt.	$ 55	Million
Maturity Date	2-Jun-08	Issue Costs	$ 0.45	Million
Payments	21	Coupon rate	6.20%	

	Semi-Annual	Annual
IRR (Effective Cost)	3.154%	6.308%

Time Period	Proceeds	Interest	Bond repayment	Cash Flow	Present Value
0	$ 54.55	$ -	$ -	$ 54.55	$ 54.55
1		(1.71)		(1.71)	(1.65)
2		(1.71)		(1.71)	(1.60)
3		(1.71)		(1.71)	(1.55)
4		(1.71)		(1.71)	(1.51)
5		(1.71)		(1.71)	(1.46)
6		(1.71)		(1.71)	(1.42)
7		(1.71)		(1.71)	(1.37)
8		(1.71)		(1.71)	(1.33)
9		(1.71)		(1.71)	(1.29)
10		(1.71)		(1.71)	(1.25)
11		(1.71)		(1.71)	(1.21)
12		(1.71)		(1.71)	(1.17)
13		(1.71)		(1.71)	(1.14)
14		(1.71)		(1.71)	(1.10)
15		(1.71)		(1.71)	(1.07)
16		(1.71)		(1.71)	(1.04)
17		(1.71)		(1.71)	(1.01)
18		(1.71)		(1.71)	(0.97)
19		(1.71)		(1.71)	(0.95)
20		(1.71)		(1.71)	(0.92)
21		(1.71)	(55.00)	(56.71)	(29.54)
					$ 0.00

Medium Term Note- Series 9 Re-Opened

Issue Date	19-Nov-98	Issue Amt.	$ 58	Million
Maturity Date	2-Jun-08	Issue Costs	$ (0.68)	Million
Payments	19	Coupon rate	6.20%	

	Semi-Annual	Annual
IRR (Effective Cost)	3.018%	6.036%

Time Period	Proceeds	Interest	Bond repayment	Cash Flow	Present Value
0	$ 58.68	$ -	$ -	$ 58.68	$ 58.68
1		(1.80)		(1.80)	(1.75)
2		(1.80)		(1.80)	(1.69)
3		(1.80)		(1.80)	(1.64)
4		(1.80)		(1.80)	(1.60)
5		(1.80)		(1.80)	(1.55)
6		(1.80)		(1.80)	(1.50)
7		(1.80)		(1.80)	(1.46)
8		(1.80)		(1.80)	(1.42)
9		(1.80)		(1.80)	(1.38)
10		(1.80)		(1.80)	(1.34)
11		(1.80)		(1.80)	(1.30)
12		(1.80)		(1.80)	(1.26)
13		(1.80)		(1.80)	(1.22)
14		(1.80)		(1.80)	(1.19)
15		(1.80)		(1.80)	(1.15)
16		(1.80)		(1.80)	(1.12)
17		(1.80)		(1.80)	(1.08)
18		(1.80)		(1.80)	(1.05)
19		(1.80)	(58.00)	(59.80)	(33.99)
					$ 0.00

Medium Term Note- Series 9 Re-Opening

Issue Date	01-Sep-99	Issue Amt.	$	75	Million
Maturity Date	2-Jun-08	Issue Costs	$	2.05	Million
Payments	20	Coupon rate		6.20%	

	Semi-Annual	Annual
IRR (Effective Cost)	3.289%	6.578%

Time Period	Proceeds	Interest	Bond repayment	Cash Flow	Present Value
0	$ 72.95	$ -	$ -	$ 72.95	$ 72.95
1		(2.33)		(2.33)	(2.25)
2		(2.33)		(2.33)	(2.18)
3		(2.33)		(2.33)	(2.11)
4		(2.33)		(2.33)	(2.04)
5		(2.33)		(2.33)	(1.98)
6		(2.33)		(2.33)	(1.91)
7		(2.33)		(2.33)	(1.85)
8		(2.33)		(2.33)	(1.79)
9		(2.33)		(2.33)	(1.74)
10		(2.33)		(2.33)	(1.68)
11		(2.33)		(2.33)	(1.63)
12		(2.33)		(2.33)	(1.58)
13		(2.33)		(2.33)	(1.53)
14		(2.33)		(2.33)	(1.48)
15		(2.33)		(2.33)	(1.43)
16		(2.33)		(2.33)	(1.39)
17		(2.33)		(2.33)	(1.34)
18		(2.33)		(2.33)	(1.30)
19		(2.33)		(2.33)	(1.26)
20		(2.33)	(75.00)	(77.33)	(40.48)
					$ 0.00

The Effective Interest Cost is calculated using the average principle outstanding and actual interest cost per contract for LILO Obligations for the three municipalities requested:

	Avg Principle Outstanding	Actual Interest Per Contract	Effective Interest Rate
	(1)	(2)	(2)/(1)
Kelowna - Primary	$26,309,100	$1,584,465	6.022%
Kelowna Additions added in 2001	$333,760	$17,868	5.354%
Kelowna Additions added in 2002	$373,181	$19,977	5.353%
Kelowna Additions added in 2003	$740,204	$41,451	5.600%
Kelowna Additions added in 2004	$990,725	$47,601	4.805%
Kelowna	$28,746,970	$1,711,362	5.953%
Nelson	$4,555,444	$323,137	7.093%
Vernon	$13,659,540	$1,107,482	8.108%

21.0 Reference: Exhibit B-1, Section A-8, p. 2

21.1 Please explain the $2.298 million difference between the Approved 2007 and the Actual 2007 Adjustment to 13-month average.

Response:

The Adjustment to 13-month Average represents an upgrade to the mid-year calculation of Net Plant in Service to reflect a 13 month average of the same. It is assumed for forecast purposes that plant activity will follow an even pattern; therefore, the Adjustment to13-month Average was forecast to be zero for Approved 2007 purposes. However, in filing the Actual (Year End Forecast) 2007 results, TGI was able to estimate the Adjustment to the 13 Month Average by utilizing the first 9 months of actual results and the last 4 months of forecast results.

21.2 Please explain the $0.596 million difference between the Approved 2007 and the Actual 2007 Construction Advances.

Response:

The difference can be attributed to the amalgamation of Squamish customer advances on January 1, 2007.

21.3 Please explain the $3.19 million difference between the Approved 2007 and the Actual 2007 Cash working capital

Response:

The $3.19 million difference between Approved 2007 and Actual 2007 Cash Working Capital is primarily related to Cost of Gas. Section A-8, Page 3 shows a 6% increase in Cost of Gas between 2007 Approved and 2007 Actual. Increased Cost of Gas leads to increased Energy Sales. The combined effect on Cash Working Capital is to drive the Cost of Gas, GST, PST, and Reserve for Bad Debts components proportionately higher.

22.0 Reference: Exhibit B-1, Section A-8, p. 2 and A-3, p. 10

22.1 Please reconcile the items on the following table:

	2007 Projection, (Application, Section A-3, p. 10)	**2007 Actual** (Application, Section A-8, p. 2)
Plant in Service, Beginning	$3,136,979	$3,067,390
Contributions in aid of construction	(152,324)	(153,619)
Accumulated Depreciation and Amortization	(651,669)	(678,209)

Response:

The 2007 projection contained in Section A-3, Page 10 shows the approved PBR formula-based amounts while Section A-8, Page 2 shows a projection of the actual non-formula amounts, used to derive the Earnings Sharing calculation found on Page 6. The items will not reconcile.

23.0 Reference: Exhibit B-1, Section B-3, Education and Outreach Initiatives, pp. 1-11

In Section 3.0 of the DSM Report TGI explains its Education and Outreach Programs. In Section 4. TGI explains its 2007 Incentive Program Descriptions.

23.1 For the years actual 2003 to 2006, projected 2007, forecast 2008 please provide a costing (budget and actual) of the various Education and Outreach Programs and any other non-grant programs. Also identify if the program is for load building or conservation. Please confirm all these costs are expensed as DSM O&M.

Response:

The following table provides actual spending for various Education and Outreach programs from 2003 to 2006 and a forecast of expenditures for 2007. A forecast for 2008 is not available at this time but will be provided when Terasen Gas submits its Energy Efficiency and Conservation application prior to the end of 2007.

Terasen Gas believes education and outreach initiatives are an important component of its overall portfolio of energy efficiency activities, helping to raise awareness and communicate the importance and benefits of energy efficiency activities. Historically, Terasen Gas has allocated a baseline level of funding of approximately $200,000 each year in support of such education and outreach activities, recognizing that the overall O&M DSM funding available is only $1.6 million. In each year, Terasen Gas manages to this level of baseline funding available, allocating funding as required to the various programs. Depending on the circumstances at the time (i.e. increased program participation) and where warranted, funding made available to each specific program may be increased or decreased. For example, general education and outreach activity expenditures increased significantly in 2005 and 2006 compared to historical spending. This is the result of the use of television media to market Terasen Gas' energy efficiency programs.

All costs listed are expensed as DSM O&M.

Year	**2003**	**2004**	**2005**	**2006**	**2007**
Program Name	**Program Amount**	**Program Amount**	**Program Amount**	**Program Amount**	**Program Amount**
Destination Conservation	$ 69,000	n/a	n/a	$ 18,000	$ 67,500
Commercial Energy Utilization Advisory	40,365.05	$ 28,189	$ 15,485	$ 75,125	$ 14,533
General Education and Outreach Activity	100,447.26	$ 127,906	$ 515,542	$ 632,583	183,365.64
Community Energy Planning Participation	20,946.20	$ 10,023	n/a	$ 10,000	$ 12,175

Please note that Program amounts <u>may</u> include accruals from the previous year as well as partner contributions
Please note that General Education and Outreach Activity for 2005 and 2006 includes Mass Media Communications
Please note that 2007 Program Amount are YTD Actual Funds Spent

23.2 For the years actual 2003 to 2006, projected 2007, forecast 2008 please provide a costing summary of the incentive programs. Also identify if the program is for load building or conservation.

Response:

Please see the table below. All programs for TGI are conservation programs. Please note that Terasen Gas intends to submit the Energy Efficiency and Conservation Application prior to the end of 2007 which will significantly modify the programs that are offered in 2008, therefore no forecast for incentive programs for 2008 has been provided below.

Year	**2003**		**2004**		**2005**		**2006**		**2007**	
Program Name	**Incentive Amount'**	**Program Amount**	**Incentive Amount**	**Program Amount**	**Incentive Amount**	**Program Amount**	**Incentive Amount**	**Program Amount**	**Incentive Amount**	**Program Amount**
Energy Star Heating Upgrade	$887,833	$397,386	$356,265	$224,645	$215,050	$133,755	$396,450	$130,692	$ 381,250	$186,350
New Construction Energy Star Heating Program	n/a	n/a	$ 75,000	$ 48,691	$375,000	$ 33,486	$ 82,500	$ -	$ 1,026,000	$ 2,617
Effiicent Boiler Program	n/a	n/a	$240,000	$242,125	$208,000	$ 52,018	$741,472	$ 37,370	$ 297,542	$ 4,800

Please note that Incentive and Program amounts <u>may</u> include accruals from the previous year as well as partner contributions
Please note Energy Star Heating Upgrade Incentive and Program Amounts for 2007 includes spending for both 2006/2007 and 2007/2008 programs
Please note that 2007 Incentive and Program Amount are YTD Actuals

24.0 Reference: Exhibit B-1, Section B-5, Code of Conduct and Transfer Pricing

24.1 Fortis Inc. stated: "…Fortis will cause the Terasen Utilities to file a review and if necessary an update to the Code of Conduct and Transfer Pricing Policy in their next revenue requirements application" (Appendix A to Order No. G-49-07, page 14 of 15).

24.1.1 Is the review by the Manager – Internal Audit Services and also by Ernst & Young intended to satisfy the commitment made by Fortis Inc? If not, please explain.

Response:

No, the reviews by the Manager – Internal Audit Services and also by Ernst & Young are not intended to satisfy the commitment made by Fortis Inc. The Company expects to fulfil this commitment with its next revenue requirements application. The Company anticipates its next revenue requirements application to be file in 2009 for the 2010 test year, in the event the current PBR Extended Settlement agreement, which expires at the end of 2009, is not further extended beyond 2009.

24.2 On page 2 the Manager Internal Audit Services states: "Based on my review 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 September 1, 2006 to August 31, 2007."

In the Ernst & Young Review Engagement Report it states: "Based on our review, nothing has come to our attention that causes us to believe that the Company is not in compliance with the Code of Conduct and Transfer Pricing Policy for the year ended August 31, 2007."

24.2.1 Are these statements the same as stating that Terasen Gas Inc. is following the Code of Conduct and Transfer Pricing Policy? Please elaborate.

Response:

Neither the internal or the external auditors reviewed 100% of transactions, so they are not in a position to provide positive assurance of compliance with the two policies. It should be noted that the internal and external auditors conducted the scope of their reviews consistent with what was agreed to in the Negotiated Settlement.

As provided in the Application, Section B-5, in the last paragraph on page 1 (excerpt below):

> “Based on their respective review procedures, both internal and external auditors concluded that 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. “

Therefore, the two statements noted in the question in each of the Internal Audit and Ernst & Young independent reviews provide “negative assurance”, that Terasen Gas Inc. is in compliance with the Code of Conduct and Transfer Pricing Policy as nothing came to their attention that would cause them to conclude otherwise based on the scope of their reviews.

Management believes it was in compliance with the code of conduct and transfer pricing policies during the period in question.

25.0 Reference: Exhibit B-1, Section B-6, Miscellaneous Information, pp. 1 to 3

25.1 Regarding Changes to CICA Handbook Section 3061 Property, Plant & Equipment, Effective January 1, 2008 on page B-6 page 2 TGI states: "A reclassification from inventory to WIP has no effect on the utility's Rate Base since both Inventory and WIP (not attracting AFUDC) are calculated based on a 13 month average balance. For forecast 2008 in this annual review, these costs are still included in inventory as part of Other Working Capital."

25.1.1 If TGI followed the CICA Handbook recommendation please file the amended regulatory schedules that reflect the new change for the 2008 Forecast year (i.e. remove from inventory and include in property, plant and equipment). Also, identify where the change is made in the regulatory schedules.

Response:

In the following table that summarizes the Utility Rate Base for 2008 shows Other Working Capital, which includes Inventory, has decreased by $6.2 million while "Work in Progress, no AFUDC" has increased by $6.2 million.

TERASEN GAS INC. 10/24/2007 10:00 Section A Tab 1 Page 6

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2008
($000s)

Line No.	Particulars	2008 Advance Materials	2008 Existing Rates	2008 Adjustments	2008 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$3,242,849	$3,242,849	$0	$3,242,849	$0	- Tab A-3, Page 8.1
2	CPCNs	10,092	10,092	-	10,092	-	- Tab A-3, Page 8.1
3							
4	Additions	128,111	128,111	-	128,111	-	- Tab A-3, Page 8.1
5	Disposals	(32,478)	(32,478)	-	(32,478)	-	- Tab A-3, Page 8.1
6							
7	Plant in Service, Ending	3,348,574	3,348,574	-	3,348,574	-	
8							
9	Add - Intangible Plant	1,614	1,614	-	1,614	-	
10							
11		3,350,188	3,350,188	-	3,350,188	-	
12							
13	Contributions In Aid of Construction	(148,162)	(148,162)	-	(148,162)	-	- Tab A-3, Page 9
14							
15	Less - Accumulated Depreciation	(765,334)	(765,334)	-	(765,334)	-	- Tab A-3, Page 15
16							
17							
18	Net Plant in Service, Ending	$2,436,692	$2,436,692	$0	$2,436,692	$0	
19							
20							
21	Net Plant in Service, Beginning	$2,398,136	$2,398,136	$0	$2,398,136	$0	- Tab A-3, Page 10
22							
23							
24	Net Plant in Service, Mid-Year	$2,417,414	$2,417,414	$0	$2,417,414	$0	
25	Adjustment to 13-Month Average	-	-	-	-	-	
26	Construction Advances	(658)	(658)	-	(658)	-	
27	Work in Progress, No AFUDC	9,358	15,558	-	15,558	6,200	
28	Unamortized Deferred Charges	(27,526)	(26,819)	-	(26,819)	707	- Tab A-3, Page 13.1
29	Cash Working Capital	(28,071)	(28,435)	364	(28,071)	-	- Tab A-3, Page 14
30	Other Working Capital	136,843	130,643	-	130,643	(6,200)	- Tab A-3, Page 14
31	Deferred Income Tax, Mid-Year	(364)	(604)	-	(604)	(240)	
	Capital Efficiency Mechanism	-	-	-	-	-	
32	LILO Benefit	(1,980)	(1,980)	-	(1,980)	-	
33	Utility Rate Base	$2,505,016	$2,505,119	$364	$2,505,483	$467	

25.2 Regarding Accounting for Rate Regulated Operations on page 3 it states: “While the Company is still assessing the differences between the current Canadian standard and the US standard (FAS 71), it appears that the Company would be required to book future income taxes on its balance sheet with an offsetting regulatory asset or liability for the amount expected to be recovered in future rates. If implemented, this change would likely result in increases to cost of service and customers’ rates.”

25.2.1 Please provide a summary of the changes required in the regulatory schedules, revenue requirement impact and resulting rate change if the tax change was implemented. If 2009 figures are not available use 2008 figures and assume that the CICA change takes effect one year earlier in order to provide an estimate of the possible impact in 2009.

Response:

During the third quarter of 2007, the Accounting Standards Board of Canada (“AcSB”) issued a Decision Summary to remove the temporary exemption in Section 1100, Generally Accepted Accounting Principles, of the CICA Handbook for entities subject to rate regulation. At the time, AcSB will amend Section 3465, Income Taxes, to require the recognition of future income tax liabilities and assets as well as an offsetting regulatory assets or liabilities for entities subject to rate regulation. Both changes will apply prospectively for TGI effective January 1, 2009. The impact on Terasen of the amendment to Section 3465, Income Taxes, will be the recognition of future income tax assets and liabilities and related offsetting regulatory liabilities and assets for the amount of future income taxes expected to be recovered from customers in future gas rates.

Currently, TGI uses the taxes payable method of accounting for income taxes on regulated earnings and records deferred charges on a net-of-tax basis. At the time when the AcSB made the announcement it also stated in the final Background Information and Basis for Conclusions for this project, that it would not express any views regarding this issue or the status of FAS 71 as an “other source of GAAP” within the Canadian GAAP hierarchy. Consequently, Terasen Gas Inc. is still assessing how elements of FAS 71 could impact its financial results and presentation.

Consequently, at this time, TGI cannot provide a reasonable estimate of the effect these Canadian GAAP changes would have on the Rate Base and Revenue Requirement.

25.2.2 Regarding International Financial Reporting Standards are there other potential changes (other than the deferral accounts mentioned on page 3) that TGI is aware of?

Response:

The effort to converge with IFRS has been likened to OSC Compliance in Canada and SOX compliance in the US in terms of complexity and potential burden to comply. Companies with limited business lines, limited locations and limited complexities will require less effort to comply with IFRS. However, the more complex the business, the more business lines, the more locations, the more accounting issues and the more complexities will result in a corresponding increase in the effort related to and the work required to comply with IFRS.

The AcSB’s Convergence Plan to address the differences between Canadian GAAP and IFRS can be summarized as follows:

- 27 standards might be converged prior to 2011 (this depends on projects between FASB and IASB and may result in more standards being converged as at 2011),
- 37 remaining standards will be converged as at 2011,
- 8 projects will still be in process at 2011,
- 3 IASB standards will be new (i.e. no equivalent Canadian standard exists), and
- 8 current Canadian standards may be disposed (rate regulated operations being one of those).

Just over half of the differing standards have slight differences, while the remaining standards have more than slight differences. However, even a slight difference in wording could cause a material difference in treatment. Furthermore, the convergence with IFRS should not be viewed as simply a compliance exercise. It will impact more than just the finance department and financial reporting. Some of the functional areas of the business that may be impacted:

- Audit Committee knowledge
- Budgets, Forecasts
- Debt covenants and financing
- Relationships with credit rating agencies and regulators
- Investor relations
- Internal Controls
- Finance department training
- Executive Compensation.

To summarize, there are many potential changes that may result from IFRS. The possibility of elimination of any guidance on rate regulated operations is one of the most obvious, but changes to property, plant & equipment and financial instruments standards are also expected to have pervasive impacts. TGI is currently involved in working towards an understanding of those impacts, but is not in a position to specifically identify or quantify them.

25.2.3 Please elaborate on the current accounting methods for deferral accounts currently allowed in the CICA Handbook and how it may change.

Response:

Under CICA Handbook Section 1100, GAAP need not be applied to the recognition and measurement of assets and liabilities arising from rate regulation. Since deferral accounts arise from rate regulation, they can be recorded for financial statement purposes in the same manner as under rate regulation.

With the removal of the Section 1100 exemption effective January 1, 2009, TGI will be required to follow general GAAP. Although TGI regulatory deferral accounts appear to meet the definition of assets and liabilities as outlined in Section 1000, a more detailed review of each account would need to be undertaken to gain assurance. Under the GAAP hierarchy, where the Handbook is silent on a specific item, alternate sources of GAAP, such as US GAAP can be looked at. Under SFAS 71, Accounting for the Effects of Certain Types of Regulation, deferral treatment is allowed for rate regulated items.

With the transition to IFRS in 2011, it is unclear if deferral accounts will continue to meet the requirements for recognition in the absence of any specific guidance on rate regulated accounting.

26.0 Reference: Exhibit B-1, Section A-4, Customer Additions Forecast, p. 4

TGI Customer Growth[1]

	2004 Actuals	2005 Actuals	2006 Actuals	2007 Projected	2008 Forecast
Residential[2]	10,716	11,427	9,595	12,764	11,098
Commercial[3]	756	1,002	656	382	704
Industrial & Transportation[4]	32	(9)	(70)	(17)	(5)
Total	**11,504**	**12,420**	**10,181**	**13,129**	**11,797**
Year-Ending Customers	786,958	799,378	812,683[6]	825,812	837,609
Housing Starts[5]	32,925	34,667	36,443	35,525	32,500

26.1 Of the 11,098 expected new Residential customers, how many does TGI expect to be Single Family Dwellings and how many are expected to be Multi-Family Dwellings?

Response:

TGI does not forecast residential building types separately, but an estimate of approximately 75% to 95% of residential customer additions coming from single family dwellings would not be unreasonable. Many townhouse developments and virtually all apartment-style construction that are serviced by natural gas do so with a common meter. These common meter multi-family buildings would come under either commercial or industrial rate classes.

27.0 Reference: Exhibit B-1, Section A-4, Use Per Customer Forecast, p. 5

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

	Normal 2004	Normal 2005	Normal 2006	Projected 2007	Forecast 2008
Rate 1	102.6	97.4	96.8	97.1	96.1
Rate 2	313.8	305.8	314.3	319.9	321.9
Rate 3	3,500.9	3,387.6	3314.1	3,445.4	3,429.0
Rate 23	5,112.6	4,714.3	4,685.7	4,916.3	4,850.0

On Page 5, the table "Historic and Forecast Usage" includes forecast usage rates for 2008 and normalized actuals for 2006. Other than residential Rate Class 1, the forecasts for 2008 show increased use rates over 2006 actuals.

27.1 For each commercial Rate Class, please list reasons why its use rate is expected to increase over its 2006 actual.

Response:

Commercial Rate Classes 2, 3, and 23 represent approximately 80,000 customers across a broad range of business activities and multi-family buildings. Potential drivers of use rate changes can only be discussed in aggregate. Continued relative stability in commercial use rates for 2008 are supported by growth in provincial GDP, low unemployment and stable natural gas commodity rates; the B.C. Government released their First Quarterly Report on September 14th, 2007 where provincial GDP was forecasted at 2.9% in 2008 and unemployment at 4.6%. All of these factors allow customers to continue to grow their business which in turn is expected to have an effect on their consumption of natural gas.

Though 2008 commercial use rates show an increase from 2006, the forecast is for use rates to remain stable in the case of Rate 2 and decline slightly for Rates 3 and 23 in comparison with 2007's projection.

28.0 Reference: Exhibit B-1, Section A-4, Commercial Sales Forecast, p. 7

Historic and Forecast Energy (PJ)

	Normal 2004	Normal 2005	Normal 2006	Projected 2007	Forecast 2008
Residential[1]	72.0	69.3	70.0	73.4	72.0
Commercial[2]	45.2	43.9	44.1	46.8	46.1
Firm Sales[3]	5.3	4.7	4.1	3.9	3.7
Industrial[4]	58.3	58.6	54.2	56.7	49.9
Total	**180.8**	**176.5**	**172.4**	**180.8**	**171.7**

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)

28.1 The "Historic and Forecast Energy" table, as above, shows that Commercial energy sales are expected to be 4.5% greater in 2008 than in 2006. Please explain why 2008 Commercial sales volumes are expected to increase over 2006, other than from changes in per-customer use rates.

Response:

The other component use to forecast energy demand is the number of customers. For the commercial rate classes (Rates 2, 3 and 23), the forecast calls for an additional 1,084 customers over 2006 levels. This increase in the number of customers along with the change in use rates accounts for the increase in energy forecasted from 2006 to 2008.

29.0 Reference: Exhibit B-1, Section A-4, TGVI Wheeling Demand Charges, p. 9

"Revenue from wheeling demand charges and odorant cost recovery remains at approximately $4.3 million for 2008."

29.1 Are increases to the above charges to TGVI due solely to the CPI?

Response:

Increases to TGVI Wheeling Demand Charge are due solely to Inflation
See Inflated Demand Rate as per below table.

Calendar Year	Inflated Demand Rate* ($mil)	Transfer Station Incremental Costs ($mil)	Spurline Incremental Costs ($mil)	Odorant Facilities ($mil)	Annual Demand Rate ($mil)
2007	$ 3.75	$ 0.05	$ 0.26	$ 0.03	$ 4.09
2008	$ 3.92	$ 0.05	$ 0.26	$ 0.03	$ 4.26

* Inflated Demand Rate per Wheeling Agreement between BC Gas Inc and PCEC, July 3, 1989 Schedule D:

30.0 Reference: Exhibit B-1, Section A-4, Customer Counts and Use Rates, p. 10

“Customer counts and use per customer rates adjusted to reflect actual results to June 2007.”

30.1 Please provide a table showing the customer counts and use-per-customer rates as of June 2007, by Tariff Rate.

Response:

The table below provides customer totals and their associated use rates by Tariff Rate. The use per customer figures represent the total actual (not normalized) consumption for the period from January 2007 to June, 2007 (inclusive).

	Total Customers as of end of June 2007	Use per Customer (GJs) during the 6 month period - Jan to Jun 2007
Rate1	734,220	56
Rate2	73,999	191
Rate3	4,705	2,113
Rate23	1,219	2,808
Rate4	40	1,829
Rate5	317	6,095
Rate6	36	1,748
Rate22	25	247,349
Rate22 Bypass	11	668,004
Rate22A	10	384,777
Rate22B	5	248,107
Rate25	597	12,488
Rate25 By	7	118,483
Rate27	96	30,822
Rate7	3	12,734

31.0 Reference: Exhibit B-1, Section B-1, Forecast of Regular Capital Expenditure Targets (2007 -2012), p. 2

31.1 Customer meter replacement is projected to escalate at a rate of 15.3%/year. What accounts for this rapid replacement cost escalation?

Response:

The decline in residential meter pricing has been significant in recent years, in part due to the appreciation of the Canadian dollar relative to the U.S. These price changes have placed significant pressure on the economics related to residential meter repair. Previously, Terasen Gas would recall residential meters at the midpoint of their expected 28 year life, recondition them and return them to service. As a result of the changing economic conditions, the Company has revised its policy such that it leaves residential meters installed for as long as possible without removing them for their mid-life service. This policy change has resulted in a pronounced short-term reduction in residential meter recalls and is expected to result in an increase in meter recalls in the coming years.

The changing economics regarding metering for residential customers has also caused the Company to explore the possibility of implementing automated meter reading ("AMR"). It is becoming more economic to factory-install AMR on new meters rather than retrofit on an installed meter population. Accordingly, Terasen Gas is of the view that it is prudent at this time to reduce the number of residential meter recalls and to more thoroughly examine the alternative to implement AMR at some point in the future. The Company is in the preliminary phases of investigating this option and will look to develop a business case over the course of the next year or two. If the AMR option proves to be the most appropriate course of action, the Company anticipates that it would bring an AMR application forward to the Commission for review, at such time.

32.0 Reference: Exhibit B-1, Application, Section B-1, Rate Base, p. 3

32.1 “New Service installations, which are installed by contractor and Terasen crews, have also been impacted by the installation contractor pricing changes and paving cost increases. Additionally, in the lower mainland, crew sizes have been temporarily increased from three to four as part of a succession planning initiative. Once employees are trained and others have retired, crew complements will return to normal.”

32.1.1 Please provide the average new service installation crew size for the Lower Mainland, the Interior and Squamish.

Response:

Lower Mainland: 3.5 (ranges between 3 and 4)

Interior: 3.0 (occasionally 2 person if larger backhoe not required)

Squamish: services installed by contractor – crew sizes may vary

32.1.2 When does TGI expect the Lower Mainland crew complements to return to normal?

Response:

The Lower Mainland crew compliments are expected to return to three person crews by end of 2009 or 2010. The year is uncertain in that it depends on the frequency of retirements over the next three years and Terasen Gas’ ability to recruit qualified replacements.

32.1.3 Will a similar succession planning initiative need to be undertaken in the Interior? If not, why not?

Response:

Terasen Gas is not currently forecasting a similar crew succession planning initiative of this size in the Interior. Generally speaking, vacancies in crew positions arising in the Interior are filled, as they come up, by external resources or by more senior employees from the Lower Mainland. Focusing this initiative on the lower mainland allows employees to be closer to the training area and to where the majority of retirements will occur.

32.2 "Other projects that were deferred to 2008 were the SAP Upgrade project, the Recorded Information Management project for Distribution and Transmission and various system improvement initiatives."

32.2.1 Please reconcile the deferral of the SAP Upgrade to 2008 to the response to following statement:

32.3 "If this program is not approved, Terasen Gas will be not be in a position to ensure that the systems supporting all back office functions (Finance, Supply Chain, HR, Payroll) as well as it's Work Management, Meter Management and Preventive Maintenance processes for the distribution network can be maintained and stable. The license agreement is for software usage, not ultimate ownership of the software. Contractually, Terasen Gas is obligated to pay SAP ongoing maintenance fees. If Terasen Gas decided to not upgrade to a supported version of the software, SAP's obligation to support the version Terasen Gas remains on is voided but it does not relieve Terasen Gas' obligation to pay the annual licensing fees. Failure to do so may be interpreted by SAP as termination of the licensing agreement and Terasen Gas would be obligated to return all software to SAP and leaving Terasen Gas to find alternative software. While the costs of finding alternative software have not been quantified, Terasen Gas believes that the cost of this would greatly exceed $10 million dollars. Terasen Gas believes this program to be prudent and in the best interest of its customers." (2006 Annual Review and Mid-Term Assessment, Review, BCUC IR 47.3)

Response:

The context of the statement quoted as per 2006 Annual Review and Mid-Term Assessment, Review, BCUC IR No. 1, Question 47.3 was the implication of the upgrade not being approved at all. Terasen Gas has deferred the start of the upgrade planning for approximately 4 to 6 months.

32.3.1 How will TGI ensure that the systems supporting all back office functions (Finance, Supply Chain, HR, Payroll) as well as its Work Management, Meter Management and Preventive Maintenance processes for the distribution network will be maintained and stable?

Response:

SAP has created a support option whereby customers on R/3 software version 4.6C (like Terasen Gas) can purchase extended support for a limited period of time. Terasen Gas is currently in the process of negotiating that extended support.

32.3.2 Given that TGI has decided to postpone the SAP Upgrade until 2008, has SAP's obligation to support TGI's version of SAP been voided?

Response:

Please refer to the response to Question 32.3.1.

32.3.3 Since TGI has decided to postpone the SAP Upgrade until 2008, has this action been interpreted by SAP as termination of the licensing agreement? If yes, has TGI been obligated to return all software to SAP and required to find alternative software?

Response:

Please refer to the response to Question 32.3.1. The deferral has not been interpreted as a notice of termination by SAP.

33.0 Reference: Exhibit B-1, Section B-1, SCP Code Compliance Upgrades, p. 5

33.1 Please identify the respective SCP Code requirement.

Response:

The SCP Code requirement is identified in Section 4 and Section 10 of CSA Z662-07.

33.2 What is the difference in the allowable operating pressure per year over the last 5 years?

Response:

The original maximum operating pressure (MOP) for SCP was 9930 kPa, and it has remained at that level over the past 5 years. To clarify, without the proposed work, the MOP may need to be reduced. Further review and analysis is underway, and a plan is being developed to address the issue.

33.3 Please provide a summary of the cost estimate.

Response:

The high level cost estimate is based on replacing 1 km of pipe at $2 million per kilometer, and six road crossings at $250,000 each. This is a high level budget number that will be adjusted as the analysis is updated.

34.0 Reference: Exhibit B-1, Section B-1, LNG Coldbox Upgrade, p. 5

34.1 A 20% increase in the overall project cost would have justified a CPCN for approval of the project. Is this project on budget? What is the projected overall cost for the project including expenditures to date?

Response:

The total budget for this project is $4,118,366, of which $ 2,853,366 or 69% represents a firm amount for the manufacture and supply of the coldbox, calculated at a 20% exchange rate. Of the 2 invoices already paid totaling $490,316, approximately $40,000 or 10% was saved through a favorable exchange rate.

The demolishing of the existing coldbox has a budget of $400,000 with a 10% contingency added. A total of $750,000 (plus 10% contingency) is budgeted for Terasen engineering, project management, inspection, electrical, piping fabrication and tie-in, crane rental, materials, foundation changes, coldbox delivery and insurance.

The Company is confident that the project will not exceed the budget and may be under budget by approximately $250,000, if the exchange rate remains at current levels until the end of the project.

The project is on schedule for completion in 2008. Total cost to date for the project is $667,303.

35.0 Reference: Exhibit B-1, Section B-1, Scada System Upgrade, p. 5

35.1 When was the last SCADA system upgrade?

Response:

The last SCADA system upgrade was completed in 1999.

35.2 Are there outside consultants that support the current SCADA version 6.0?

Response:

There are no outside consultants that support the current SCADA version 6.0.

35.3 If there are outside consultants that support this version what benefits are offered by the upgrade that would justify a replacement of the version 6.0?

Response:

Since there are no outside consultants that support the current SCADA version 6.0, an upgrade is being considered to maintain timely vendor support.

36.0 Reference: Exhibit B-1, Section B-1, Kootenay River (near Shoreacres) Crossings, p. 6

36.1 Please provide your cost/benefit analysis that compares horizontal directional drilling over the replacement of the aerial crossing.

Response:

Terasen Gas has obtained the consulting services of Buckland and Taylor for this project. Based on the estimates prepared by Buckland and Taylor, the cost to upgrade the existing aerial crossing is $1.83 million plus internal costs of an additional 15%. This estimate is considered to be within +/- 25% of actual costs. In addition, approximately $7,000 per year will be incurred for semi annual inspections and maintenance.

The horizontal directional drilling costs is estimated to be approximately $2 million, based on preliminary estimates from Entec, the Company's engineering consultant. The ongoing inspections and maintenance costs are estimated to be approximately $1,000 per year.

37.0 Reference: Exhibit B-1, Section B-1, Columbia River Crossing near Brilliant, p. 6

37.1 Please provide your cost/benefit analysis that compares horizontal directional drilling over the replacement of the aerial crossing.

Response:

Based on the Buckland and Taylor report, the cost estimate to upgrade the existing aerial crossing is approximately $2.52 million plus internal costs of an additional 15%. This estimate is considered to be within +/- 25% of actual costs. The estimated ongoing operating costs for semi annual inspections and maintenance are approximately $7,000 per year.

Based on preliminary estimates from Entec, the horizontal directional drilling is estimated to cost approximately $2 million with ongoing inspections and maintenance costs of approximately $1,000 per year.

38.0 Reference: Exhibit B-1, Section B-1, Riverside IP, Abbotsford, p. 6

38.1 When planning for this project what load forecast is it based on?

Response:

The need for this system improvement was identified through internal load information memos (generated from customer additions) directed into the Company’s routine system capacity modeling and an assumption that the greenhouse operations in the area will become firm customers. As with any system improvement, the improvements will only be undertaken if firm load warrants the improvement or the loss of interruptible revenue from curtailment exceeds the cost of the system improvement. The Company will be reviewing the viability of this system improvement again in the new year to determine if there is a desire on the part of greenhouses for firm load. If it is not economically viable to proceed with the planning for this system improvement at that time, the project would be cancelled or moved to a later date.

39.0 Reference: Exhibit B-1, Section B-1, 72nd Street IP, Delta, p. 6

39.1 How many greenhouses will potentially be affected by this system improvement?

Response:

There are 8 large greenhouse operations within 6 km (east and west) of 72nd Street.

39.2 Of the greenhouses that will be affected how many have committed to firm load?

Response:

One greenhouse has committed to firm load at this time. Please also refer to the response to Question 38.1.

39.3 Please confirm that in addition to converting some, or all, of their interruptible load to firm load, the greenhouses will be required to sign take or pay contracts before the Distribution Plant – 72nd Street and 36th Avenue IP, Delta system improvements will be installed. If take or pay contracts are not required from the greenhouses, please explain how TGI will ensure the economic viability of the system improvements.

Response:

Terasen Gas does not typically request a take or pay contract, or other form of security, above and beyond the signing of a firm contract prior to a system improvement. However, there may be circumstances where the Company believes a take or pay contract is required and, if so, would apply to the Commission for approval of the contract at that time. Please also refer to the response to BCUC IR No. 1 (Exhibit B-5), Question 16.1 of the Terasen Gas Inc. 2005 Annual Review for 2006 Revenue Requirements in respect of its 2004-2007 Multi Year PBR (excerpt below):

16.0 *Reference: Tab B-1, p. 5, 72nd Street to 36th Ave. Delta, Gouty Road and 36th Ave., Delta, 34 B Avenue to 57th Street, Delta*

16.1 When must the greenhouse customers commit to firm loads for these projects to move ahead?

Response:

The vast majority of Greenhouse Customers are Rate Schedules 22 and 27 customers.

When greenhouse customers apply for initial service, the terms of the initial contract are negotiated. When negotiating contracts, Terasen Gas considers the system requirements necessary to serve the incremental load. Once it has considered the system design and any modifications required, it is then is in a position to determine the advance notice the customer is required to commit.

Should an existing greenhouse customers wish to switch from interruptible to firm Transportation Service, the customer must commit to firm loads at least one year in advance of these projects being installed. However, Terasen Gas will make reasonable efforts to accommodate a shipper on less than 12 months notice.

An excerpt from the terms and conditions for Rate 22, Section 3.3 can be found below:

> ***3.3 Warning if Switching from Interruptible to Firm Transportation Service or Sales*** *- A Shipper wishing to switch from interruptible transportation or interruptible sales to a firm sales Rate Schedule, or to firm transportation under this Rate Schedule, or to increase their Firm DTQ under this Rate Schedule must comply with the requirements for Firm service set out in the applicable Rate Schedule, including the following*
>
> *(a) give 12 months prior notice to Terasen Gas of the Shipper's desire to do so, and*
>
> *(b) after receiving an estimate from Terasen Gas of costs Terasen Gas will reasonably incur to provide such service, agree to reimburse Terasen Gas for any such costs.*
>
> *Notwithstanding Section 3.3(a), Terasen Gas will make reasonable efforts to accommodate a Shipper on less than 12 months' prior notice if Terasen Gas is able, with such shorter notice, to arrange for the firm purchase and firm transportation of Gas under a firm sales Rate Schedule, or transportation under a firm transportation Rate Schedule.*

40.0 Reference: Exhibit B-1, Section B-1, 36th Avenue IP, Delta, p. 7

"This system improvement will only be installed if the affected greenhouses convert some, or all, of their interruptible load to firm load."

40.1 Please provide the exact load threshold you have determined to be acceptable and a justification for this approach.

Response:

An "exact threshold" cannot be defined at this time as a more detailed cost estimate is required prior to discussing this matter with the customers to determine which operations may be interested in firm contracts, dates of when firm contracts would come into effect, and how much firm load may be agreed to. Terasen Gas would also review the revenue potential of the greenhouse operations and estimate the benefit to the greenhouse operations of a non-interruptible contract.

41.0 Reference: Exhibit B-1, Section B-1, Gateway Project, p. 7

41.1 When is this application to be filed with the Commission?

Response:

The Company is of the view that an application will be needed if the amount of cost recovery is $5 million less than the capital costs, which are currently estimated at $26 million. In other words, if the net costs (capital costs less cost recoveries) are in excess of $5 million, the Company is of the view that a CPCN application will be required, pursuant to the terms of the Extended Settlement agreement. At this point in time, the Company is hopeful that the net costs will be less than $5 million, therefore it has not proposed an application.

41.2 When do you expect discussions with MoT on cost recovery principles to be concluded?

Response:

Terasen Gas and Gateway (representatives from Ministry of Transportation and Ministry of Attorney General) are currently in discussion respecting a series of agreements including a "Framework Agreement", in which it is expected to address in detail the cost recovery principles. Other agreements include: a site or segment specific "Relocation Agreement" template and a new "Highway Crossing permit" template. The goal of both parties is to finalize and sign the agreements by December 31, 2007.

42.0 Reference: Exhibit B-1, Section B-1, SAP Core Application Upgrade, p. 8

42.1 Although vendor support for the current version of SAP (R3 v4.6C) expired in the fourth quarter of 2006 there is consultant support for older versions of SAP. Please provide the cost/benefit analysis for replacing the current version with the alternative of using independent consultants for support.

Response:

There is no consultant support model that replaces the support model provided by SAP. Terasen Gas has a strong internal support team which provides the day-to-day support of Terasen Gas’ business processes, configuration and front-line technical support and has its own network of supplemental support for the Terasen Gas-specific functionality. The support that is provided by SAP is unique to the vendor. No one else has the ability to support and commit to the quality of the support of the entire system like SAP. No consultant has that kind of expertise. Consultants could perform the same support functions as the internal Terasen Gas staff but would be just as dependent on SAP, as Terasen Gas staff are, to ensure the system is stable.

42.2 How long has the current version of SAP (R3 v4.6C) been in place?

Response:

Terasen Gas went live on version 4.6C late October, 2001.

42.3 What additional enhancements are offered in the replacement version of SAP that is essential to Terasen Gas?

Response:

The key component of the upgrade for Terasen Gas is to continually assure a stable, supported environment. As part of the upgrade planning process, Terasen Gas will undergo the analysis of the new version to determine what new functionality enhancements Terasen Gas could take advantage of in a cost-effective manner. As with all Terasen Gas initiatives, the appropriate justification and approval processes will be followed for any significant increase in functionality requested by the business.

43.0 Reference: Exhibit B-1, Section B-1, Asset Integrity Integration Project, p. 8

43.1 Who is the vendor for this management software?

Response:

The Asset Integrity Integration Project is currently in the evaluation phase, preparatory to developing a business case to proceed. Therefore, there is no single vendor to support the project. As the name implies, the integration of various data sources is the key to this initiative. While the outcome of the detailed analysis may lead to the recommendation to obtain some additional software to better support the business process, the current business model is supported by many applications: R/3 from SAP, AM/FM from GE Smallworld, Scada from Telvent Automation, Excel from Microsoft as well as data provided by third parties such as BGC Engineering. No additional software has been identified to date.

43.2 Are there other utilities which currently use this data base management software? If so, who are they?

Response:

In terms of utilizing the above software packages, there are literarily hundreds of utilities using some combination of the above mentioned software or competitors products to manage the integrity of their assets,

43.3 Why was this vendor selected?

Response:

Terasen Gas has not chosen any specific software for the integration project that it did not already own. One of the key deliverables of the project is to determine the requirements and justify the acquisition of any additional software it may recommend.

43.4 Is this software compatible with existing data base management software that is already in use?

Response:

As part of Terasen Gas' standard practice, any new software introduced into the Terasen Gas environment will need to be compatible with the software currently in use unless there are compelling business reasons as to why an exception must be made.

44.0 Reference: Exhibit B-1, Section B-3, NPV of GHG Emissions, p. 5

44.1 What (average) percentage reduction in GHG emissions was achieved by the Energy Star Heating System Upgrade program?

Response:

Terasen Gas assumes simple annual consumption for a standard furnace is 60 GJ/year. Simple annual consumption reduction resulting from the replacement of a standard furnace with a high-efficiency furnace is assumed to be 13.8 GJ/year. Given a GHG emissions factor for natural gas of 0.05069 tonnes/GJ, the resultant average percentage reduction in GHG emissions was 23%.

44.2 What (average) percentage reduction in GHG emissions was achieved by the New Construction Energy Star Heating System Program/PowerSmart New Home Program?

Response:

Terasen Gas assumes simple annual consumption for a standard furnace is 60 GJ/year. Simple annual consumption reduction resulting from the selection of a high-efficiency furnace in new construction is assumed to be 9.1 GJ/year. Given a GHG emissions factor for natural gas of 0.05069 tonnes/GJ, the resultant average percentage reduction in GHG emissions was 15%.

44.3 What is the rationale for using the WACC discount rate to determine the NPV of the reduction in GHG emissions?

Response:

A standard clause in the Terms and Conditions section of the customer application form for Terasen Gas’ energy efficiency programs reads: “By taking part in this offer, your central heating system may use less natural gas and produce fewer emissions. You agree Terasen Gas may record any resulting emission reductions you have along with those of other participating customers and credit them to our Greenhouse Gas Management Program.“ Because reductions in customer emissions from Terasen Gas’ energy efficiency programs can be credited to the Company’s GHG emissions management program, it was felt that the most appropriate discount rate to use in the calculation of the NPV of the GHG emissions reductions is the Company’s WACC.

45.0 Reference: Exhibit B-1, Section B-3, 2007 DSM Status Report, pp. 5 and 8

"The method of presenting energy savings from DSM activity has changed from that presented in previous years to reflect this improved model. In previous Annual Reviews, energy savings have been presented as simple annual savings. Energy savings and cost/benefit test results are presented in the 2007 Annual Review as the present value of the savings over the measure life, to more appropriately represent energy savings from DSM activity."

45.1 For each of the DSM programs listed on Application, Section B-3, p. 8, please a provide a schedule showing the simple annual savings (previous Annual Reviews) and the present value of the savings over the Measure Life (2007 Annual Review).

Response:

Please see the table below.

Program Name	Number of Participants	Savings per Participant per Year (GJ)	Measure Life (Years)	Simple Annual Savings (GJ/year)	NPV Energy Savings over Measure Life (GJ)	GHG Savings over Measure Life (tonnes)
Energy Star Heating System Upgrade	4316	13.8	20	59,561	344,369	17,456
New Construction Energy Star Heating System Program	2981	9.1	20	27,127	250,950	12,721
Efficient Boiler Program	20	14650*	25	14650*	155,041	7,859
Destination Conservation	44	113	3	4,972	13,315	675
Commercial Energy Utilization Advisory	100	600	15	60,000	439,921	22,300

* Please note that the savings for the Efficient Boiler Program are not presented per participant per year, but are instead an aggregate of savings for all participants for the year.

46.0 Reference: Exhibit B-1, Section B-3, Cost of DSM Programs, p. 8

The Summary table on page 8 shows the results for 5 DSM Programs.

46.1 What are the forecast costs associated with each of the programs listed for 2007?

<u>Response:</u>

Please refer to the table presented in response to Question 23.2.

46.2 What were the actual costs associated with each of the programs listed for 2006?

<u>Response:</u>

Please refer to the table presented in response to Question 23.2.

46.3 For each of 2006 actual and 2007 forecast DSM expenditures, what percentage of gross revenues do they represent?

<u>Response:</u>

As the tables referenced above address solely incentive programs, and do not include education and awareness components, it may be more appropriate to review allowable DSM expenditures as a percentage of gross revenues. This information is presented in the table below.

Year	2006	2007
Administration, Program Costs, Marketing and Research	$1,624,000	$1,624,000
Customer Incentives	$1,500,000	$1,500,000
Total Allowable DSM Expenditure	$3,124,000	$3,124,000
Gross Revenues	$1,483,459,000	$1,512,496,000
Allowable DSM Expenditure as a Percentage of Gross Revenues	0.21%	0.21%

46.4 What is TGI's target DSM expenditure in terms of percentage of gross revenues?

Response:

At this time, Terasen Gas does not have a target DSM expenditure in terms of percentage of gross revenues. However, Terasen Gas's approved DSM expenditure is the lowest DSM expenditure compared to all other gas utilities in Canada. Terasen Gas intends to request an increased level of DSM expenditure in the Energy Efficiency and Conservation Application that will be filed prior to the end of 2007.

47.0 Reference: Exhibit B-1, Section B-3, Savings Targets, p. 8

47.1 Please show how each of the five listed DSM programs performed versus their savings targets, for 2006.

Response:

Please see the table below.

Program Name	Projected Number of Participants	Actual Number of Participants
Energy Star Heating Upgrade	3300	3,563
New Construction Heating Program	750	1,180
Power Smart New Home Program	300	0
Efficient Boiler Program	98	30
Commercial Energy Utilization Advisory	60	18
Destination Conservation	18	4

47.2 Please show how each of the five listed DSM programs performed versus their savings targets, for year-to-date 2007.

Response:

The information presented in the referenced table for three of the programs listed reflects year-to-date participation. The Efficient Boiler Program and Destination Conservation participation rates are YTD actuals. The New Construction Energy Star Heating System Program is now closed, so participation rates are reflective of incentives paid out in 2007 as well as incentives committed on the basis of signed Memoranda of Agreement with builders and developers. Of the 100 Commercial Energy Assessments estimated for 2007, 59 assessments had been completed at June 30, 2007. For the Energy Star Heating System Upgrade Program, 3,666 applicants had participated from January to August 2007. Terasen Gas expects a further 650 participants between September and December 2007, as the heating season gets underway.

48.0 Reference: Exhibit B-1, Application, Section B-3, 2007 DSM Status Report, p. 8

48.1 For each of the DSM programs listed on Application, Section B-3, p. 8, please provide a schedule showing the Rate Impact Measure net cost/benefit.

Response:

This information was provided in the table on the page referenced in the information request. Please refer to the column headed "RIM Result" for the Rate Impact Measure ("RIM") cost/benefit ratio for the programs listed.

48.2 Using a Free Rider Rate of 25 percent, please recalculate the RIM result, Participant Result, TRC Result, TRC Net Benefit and Rate Impact Measure net cost/benefit for the Energy Star Heating System Upgrade program.

Response:

Please see the table below.

Program Name	Free Rider Rate (%)	RIM Result	Participant Result	TRC Result	TRC Net Benefit
Energy Star Heating System Upgrade	25	0.88	3.14	2.08	$3,087,563

49.0 Reference: News Release, Office of the Premier, 28 September 2007,

"Premier Outlines New Steps to Tackle Climate Change"

"The Province will introduce new legislative measures this fall that will mandate greenhouse gas reduction targets and provide legal tools to implement government's strategy to reduce greenhouse gas emissions by 33 per cent below current levels by 2020, Premier Gordon Campbell announced today at the Union of British Columbia Municipalities convention."

49.1 Please calculate the contribution that TGI's existing DSM programs, if carried forward, will make toward achieving a 33% reduction in GHG emissions associated with current natural gas applications.

Response:

Since 1995, Terasen Gas has been voluntarily reducing GHG emissions and has achieved GHG emissions of 6% below 1990 levels in its own operations since 2000. Terasen Gas has not, to date, conducted a detailed, segmented inventory of GHG emissions from its customers' use of natural gas applications. While Terasen Gas' DSM program has existed in its current form since 1997, the widespread attention being paid to GHG emissions and opportunities to reduce GHGs is a much more recent phenomenon. GHG emission reductions are just one outcome from DSM programming; customer GHG emission reductions have not historically been the primary driver behind Terasen Gas' DSM activity. While GHG emission reductions from DSM activity can be quantified at a high level, GHG emission reductions have not been a factor to date in the cost/benefit analysis that Terasen Gas conducts on DSM programs. As per the information contained in the table on page 8 of section B-3, the DSM status report, the Net Present Value of GHG savings from Terasen Gas' DSM activity in 2007 over the lives of the various measures is 61,010 tonnes.

49.2 What other DSM measures could TGI consider in order to realize a 33% reduction in GHG emissions by 2020?

Response:

Terasen Gas has conducted a Conservation Potential Review (CPR), the results of which were reported at a high level in the 2006 Annual Review. Since receiving the CPR, Terasen Gas has been working to refine the assumptions used in the analysis conducted in the CPR, with a view to using the refined analysis as the basis for the Energy Efficiency and Conservation Application that the Company intends to file before the end of 2007. If successful, Terasen Gas would then move ahead with implementation of the various measures and programs outlined in the Energy Efficiency and Conservation Application. These Energy Efficiency and Conservation measures and programs would provide the Company, its customers, and society in general with multiple benefits, one of which would be GHG emission reductions.

In addition to traditional DSM activity, there are additional opportunities for Terasen Gas to help customers to reduce GHG emissions. For example, the System Extension and Customer Connection Policy Review Application that Terasen Gas filed July 31 2007 included proposals to encourage customers to install gas fired space and water heating and high efficient gas fired space and water heating. In that application the Company noted that it provided argument in the BC Hydro Rate Design proceeding that "if the additional space and water heating loads are served directly by natural gas instead of through gas fired electricity generation at the margin, the GHG savings would be expected to be in the range of approximately 1,200,000 to 1,500,000 tonnes over the same period (2008-2020)". Therefore, if the changes sought in the System Extension and Customer Connection Policy Review Application are approved the Company would expect that regional GHG reductions will occur because of the use of natural gas.

49.3 Does TGI believe that it can both meet the proposed GHG reduction target, and maintain, if not increase, its customer base? Please explain.

Response:

Terasen Gas is a low-carbon energy delivery company. Natural gas is delivered through the distribution network of underground pipes. Natural gas has the lowest GHG emissions of all fossil fuels, therefore customers converting from wood, propane or heating oil to natural gas can immediately reduce their GHG emissions simply by selecting natural gas as their fuel of choice. The direct use of natural gas for space and water heating has a significantly lower GHG impact than using electricity that is generated through the combustion of natural gas or coal in relatively inefficient electrical generation facilities for space and water heating. The electrical grid in British Columbia is not an island; it is connected to the rest of the electrical grid in Western North America. A significant portion of electrical generation in Western North America is relatively inefficient and uses natural gas or coal as the primary energy input to create another form of energy – electricity. Because electricity flows across the grid to wherever it is needed, and because BC Hydro actively engages in electricity trading, using electricity anywhere in Western North America for space and water heating will mean that at least some of the time, the electricity required will have been generated in an inefficient thermal or gas turbine generation facility. This means that today, adding new space and water heating customers to the natural gas system results in a lower GHG impact than adding new space and water heating customers to the electrical system in the province. The Province of British Columbia has set some policy goals related to electrical self-sufficiency and electrical GHG neutrality, however neither a comprehensive plan nor a budget for meeting these policy goals and the resultant rate impacts are available at this time. In light of this uncertainty as to the plan and costs of meeting Government's electricity policy goals, it is Terasen Gas' belief that the efficient end use of natural gas is today, and will continue to be into the future, a highly attractive option, both economically and environmentally. Further, Terasen Gas can take measures to reduce emissions from its own operations to meet provincial goals, and the Company can implement programs to assist customers in making investments in reducing their GHG Emissions, however Terasen Gas alone cannot meet the targets set out by the Government of British Columbia on September 28. Meeting the targets set by Premier Campbell will require a concerted effort, along with the appropriate investment, by all levels of government, by industry, by business, by utilities, and by individuals.

50.0 Reference: Affiliate Transactions

50.1 Please provide a list of personnel (with position) that are both TGI employees and Fortis Inc. or Fortis affiliate employees. Please explain the nature of the relationship and the costing methodology and amount.

Response:

David C. Bennett is an employee of FortisBC and has been appointed Vice President & General Counsel and Corporate Secretary to Terasen Inc. and Terasen Gas Inc. Mr. Bennett's costs are recovered from Terasen Inc. by FortisBC pursuant to its regulatory requirements. Legal services provided by Terasen Inc. to Terasen Gas Inc. are covered under the management services agreement between Terasen Inc. and Terasen Gas Inc.

50.2 Please provide a detailed schedule of shared services with Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. for 2006.

Response:

The total shared services costs – direct and allocated between TGI and TGVI for 2006 were set in accordance with the Shared Services Management Report dated May 31, 2004, which was approved in Commission Order No. G-112-04.

	2006 Total
Allocation of Shared Services Costs	4,508,231
Direct OPEB Costs	332,070
Direct Timesheet based Charges to O&M	150,300
Total Shared Services Costs - Direct and Allocated	**$ 4,990,601**

There were no shared services between TGI and TGW for 2006.

50.3 Please provide a schedule of charges and recoveries between TGI and non-regulated businesses for 2006.

Response:

The following is a schedule of shared service and management fee charges/ recoveries between TGI and non-regulated businesses (including Terasen Inc.) for 2006.

Charges to Non-Regulated Businesses from TGI in 2006

Terasen International Inc.	$10,936
Terasen Utility Services Inc.	20,784
Terasen Energy Services Inc.	73,226
Inland Energy Corp.	2,288
Terasen Huntingdon Inc.	77,207
Terasen Inc.	211,355
Terasen Inc. - IT and facilities management fee	610,026
Kinder Morgan Canada Inc .- payroll management fee	199,258
Kinder Morgan Canada Inc. - payroll system set-up fee	148,482
Terasen Energy Services Inc. - company set-up fee	17,273
	1,370,835

Charges from Non-Regulated Businesses to TGI in 2006

Terasen Inc.	8,535,000
Inland Energy Corp.	8,400
	8,543,400

50.4 Please provide a schedule of charges and recoveries between TGI and Terasen Inc. for 2006.

Response:

Please refer to the response to Question 50.3.

51.0 Reference: 2006 Annual Review Undertakings, Exhibit B-8, Main Extension Review, p. 3

"Terasen Gas further confirms that items such as the treatment, within the MX Test, of the $1.05 toll paid to TGVI for service to customers in Squamish, will be considered during the review."

51.1 Please explain how the TGI and Terasen Gas (Vancouver Island) Inc. System Extension and Customer Connection Policies Review Application addressed the $1.05 toll paid to TGVI for service to customers in Squamish.

<u>Response:</u>

As per Section 7 of Special Direction #3, the $1.05 toll paid to TGVI by TGI for service to customers in Squamish must be recorded in the Midstream Cost Reconciliation Account ("MCRA") by TGI. Special Direct 3 further states "in regulating and fixing rates, for amalgamated TGI, the commission must treat the area served by TGS as at December 31, 2006 as being within the "Lower Mainland Service Area"…". The effect of this direction is that customers in Squamish pay the postage stamp delivery, midstream and commodity charges that customers within the Lower Mainland service area pay. Customers in Squamish do not pay a different midstream rate than those customers in Abbotsford or North Vancouver regardless of the actual midstream costs to the individual communities.

The current TGI (Lower Mainland) main extension test is a 20 year discounted cash flow ("DCF") test that determines the economic viability of a main extension by looking at the ratio of discounted revenues over discounted costs. The revenues used in the tests are the delivery margin revenues. Costs include such items as capital costs, overhead, O&M, and system improvements. The TGI main extension test does not currently include either commodity or midstream costs within the test as these are flow through costs to the customer.

In reviewing the main extension test prior to the submission of the application, both TGI and TGVI decided that the most appropriate main extension test going forward was to use the current DCF test with modifications to, and treatment of the service line cost allowance, the service line installation fee, and energy efficiency and conservation credits. TGI and TGVI did not feel that either the inclusion of midstream or commodity costs or the inclusion of midstream and commodity revenues were appropriate in the test as these are flow through items to customers and as such offset each other. TGI also did not feel it appropriate for customers in Squamish to have a different main extension test than other customers in the TGI service territory. This would have occurred if the $1.05 midstream toll was included in the main extension test for Squamish customers and midstream costs were not included in the MX test for other TGI customers. Further, this approach is consistent with Special Direction #3 that directs the Commission for regulatory purposes to treat the Squamish area as being within the Lower Mainland Service Area; different MX Tests would not be consistent.

51.2 Please provide the projected 2007 total cost related to the $1.05 toll paid to TGVI for service to customers in Squamish.

Response:

Projected 2007 Transportation Charge

Squamish Delivered Volume (GJ)	382,560
TGVI Toll - $ / GJ	$ 1.05
Projected Transportation Charges	$ 401,688

52.0 Reference: Commission Order No. G-33-07, Revenues, p. 9

"Revenues will be forecast each year and the company is at risk within the year for variances in industrial revenues, customer additions, applications for service and account transfers."

52.1 Please provide the Projected 2007 and Forecast 2008 application for service and account transfer revenue.

Response:

The total revenues forecasted for application fees from new services are $1,116,000 and $1,002,700 for 2007 and 2008 respectively. The total revenues forecasted from account transfer fees are $2,843,100 and $2,766,100 for 2007 and 2008 respectively.

53.0 Reference: Commission Order No. G-33-07, Review of DSM Funding and Economic Tests, p. 18

53.1 Please file a copy of the review of the economic tests used to evaluate the DSM and efficiency programs.

Response:

Please refer to Attachment 53.1

54.0 Reference: Order of the Lieutenant Governor Council (“OIC”) No. 768, Section 18

Expiry of special direction

OIC No. 768, Section 18

This Special Direction ceases to have any application when Special Direction 1510 ceases to have any application.”

54.1 When is Special Direction 1510 expected to cease?

Response:

Section 1.3 of Special Direction 1510 provides that the term of that Special Direction shall cease to have any application after the latest of: RDDA is reduced to 0, the date of the expiration or termination of the JVTSA (to be no later than January 1, 2011), and the date of termination of the Transportation Service Agreement for provision of service to what is now the Squamish service area of Terasen Gas Inc. Section 6.01 of that Transportation Service Agreement (as amended) provides that the agreement shall continue until the later of (i) the date when the RDDA is reduced to zero, and (ii) the upon which the Commission establishes a new rate for the transportation of gas to Squamish.

55.0 Reference: Exhibit B-1, Application, Section A-3, p. 6

Commission Order No. G-160-06, Appendix A, p. 6

OIC No. 768, Section 11

"OIC No. 768, Section 11

The Commission must, for so long as the PBR remains in force, treat the rate base of amalgamated TGI as being,

(a) on January 1, 2007 an amount equal to

(i) TGS's rate base as at December 31, 2006, plus

(i) TGI's rate base as determined under the PBR, as at December 31, 2006, and

(b) after that, the amount referred to in paragraph (a) as adjusted under the PBR"

55.1 For the Squamish Amalgamation into TGI CPCN, please explain the Approved 2007 amount of $8.137 million and the Adjusted 2007 amount of $6.712 million.

Response:

They are two reconciling items in the explanation of the different amounts. The first is that the "Approved 2007" amount is a projected number, whereas the "Adjusted 2007" amount is an actual. The second part of the explanation is that the former amount is a "gross" plant balance, whereas the latter amount is a "net" plant balance. The Approved 2007 amount of $8.137 was the amount included in the 2006 Advance Material filing, which was the best projection TGI had at the time for the Squamish 2007 year end *gross* plant balance. The $6.712 million is the Squamish actual year end *net* plant balance after deducting Accumulated Depreciation. The Actual gross plant balance was $8.517 million from which the actual accumulated depreciation amount of $1.805 million was deducted to arrive at the actual net plant balance of $6.712 million.

55.2 Please confirm that the January 1, 2007 rate base of the amalgamated TGI and TGS is an amount equal to TGS's rate base as at December 31, 2006, plus TGI's rate base as determined under the PBR, as at December 31, 2006.

Response:

Confirmed. January 1, 2007 rate base of the amalgamated TGI and Squamish is an amount equal to the Squamish rate base as at December 31, 2006, plus TGI's rate base as determined under the PBR, as at December 31, 2006.

55.3 Please explain the TGS Amalgamation Adjustment of $1,805,000.

<u>Response:</u>

Please refer to the response to Question 55.1.

Attachment 2.2

ECONOMICS | RESEARCH

FINANCIAL MARKET FORECASTS

October 2007

Interest rates

%, end of quarter

	Actual							Forecast					Annual		
	Q106	Q206	Q306	Q406	Q107	Q207	Q307	Q407	Q108	Q208	Q308	Q408	2006	2007	2008
Canada															
Overnight rate	3.75	4.25	4.25	4.25	4.25	4.25	4.50	4.50	4.50	4.50	4.50	4.75	4.25	4.50	4.75
3-month T-bills	3.86	4.30	4.15	4.15	4.17	4.43	3.97	4.25	4.25	4.30	4.45	4.80	4.15	4.25	4.80
2-Year GoC bonds	3.99	4.40	3.89	4.03	3.98	4.61	4.12	4.45	4.45	4.65	4.85	5.00	4.03	4.45	5.00
5-Year GoC bonds	4.16	4.49	3.88	4.00	4.02	4.58	4.24	4.50	4.50	4.75	4.95	5.00	4.00	4.50	5.00
10-Year GoC bonds	4.26	4.61	3.99	4.09	4.13	4.59	4.35	4.55	4.65	4.80	5.00	5.05	4.09	4.55	5.05
30-Year GoC bonds	4.27	4.66	4.08	4.14	4.21	4.51	4.44	4.60	4.70	4.85	5.05	5.10	4.14	4.60	5.10
Yield Curve (2's-10's)	27	21	10	6	15	-2	23	10	20	15	15	5	6	10	5
United States															
Fed Funds rate	4.75	5.25	5.25	5.25	5.25	5.25	4.75	4.50	4.50	4.50	4.50	5.00	5.25	4.50	5.00
3-month T-bills	4.53	4.89	4.77	4.90	4.92	4.69	3.64	4.00	4.10	4.25	4.50	4.60	4.90	4.00	4.60
2-Year bonds	4.82	5.21	4.67	4.82	4.60	4.93	3.94	4.15	4.25	4.55	5.10	5.25	4.82	4.15	5.25
5-Year bonds	4.81	5.18	4.56	4.71	4.55	4.97	4.19	4.35	4.50	4.70	5.20	5.30	4.71	4.35	5.30
10-Year bonds	4.85	5.22	4.62	4.72	4.65	5.06	4.53	4.65	4.75	4.95	5.25	5.35	4.72	4.65	5.35
30-Year bonds	4.90	5.28	4.76	4.83	4.83	5.16	4.79	4.85	5.00	5.20	5.50	5.60	4.83	4.85	5.60
Yield Curve (2's-10's)	3	1	-5	-11	4	14	60	50	50	40	15	10	-11	50	10
Yield Spreads															
3-month T-bills	-0.67	-0.59	-0.62	-0.75	-0.75	-0.26	0.34	0.25	0.15	0.05	-0.05	0.20	-0.75	0.25	0.20
2-Year	-0.83	-0.81	-0.78	-0.80	-0.62	-0.32	0.18	0.30	0.20	0.10	-0.25	-0.25	-0.80	0.30	-0.25
5-Year	-0.65	-0.69	-0.68	-0.71	-0.53	-0.39	0.06	0.15	0.00	0.05	-0.25	-0.30	-0.71	0.15	-0.30
10-Year	-0.59	-0.61	-0.63	-0.62	-0.52	-0.47	-0.18	-0.10	-0.10	-0.15	-0.25	-0.30	-0.62	-0.10	-0.30
30-Year	-0.63	-0.62	-0.68	-0.69	-0.63	-0.65	-0.35	-0.25	-0.30	-0.35	-0.45	-0.50	-0.69	-0.25	-0.50

Exchange rates

%, end of quarter

	Actual							Forecast				
	Q106	Q206	Q306	Q406	Q107	Q207	Q307	Q407	Q108	Q208	Q308	Q408
Australian dollar	0.72	0.74	0.75	0.79	0.81	0.85	0.89	0.87	0.89	0.88	0.87	0.86
Brazilian real	2.16	2.17	2.17	2.14	2.06	1.93	1.83	1.87	1.90	1.92	1.93	1.94
Canadian dollar	1.17	1.12	1.12	1.17	1.15	1.07	0.99	0.97	0.98	1.02	1.04	1.07
Chinese renminbi	8.02	7.99	7.90	7.81	7.73	7.61	7.51	7.35	7.30	7.25	7.15	7.10
Euro	1.21	1.28	1.27	1.32	1.34	1.35	1.43	1.42	1.44	1.42	1.38	1.36
Japanese yen	118	114	118	119	118	123	115	120	122	122	120	118
Mexican peso	10.87	11.34	10.98	10.82	11.04	10.81	10.94	11.15	11.20	11.22	11.27	11.30
New Zealand dollar	0.62	0.61	0.65	0.70	0.71	0.77	0.76	0.75	0.78	0.77	0.75	0.73
Swiss franc	1.30	1.22	1.25	1.22	1.22	1.22	1.16	1.18	1.17	1.18	1.20	1.22
U.K. pound sterling	1.74	1.85	1.87	1.96	1.97	2.01	2.05	2.06	2.07	2.03	1.96	1.93

Note: Rates are expressed in currency units per US$ except the Euro, UK pound, A$ and New Zealand dollar, which are expressed in US$ per currency unit.

Source: Bank of Canada, Federal Reserve Board, Reuters, RBC Economics Research forecasts

Table 1—Key Economic Indicators
(Forecast completed September 17, 2007)

	2007:1	2007:2	2007:3	2007:4	2008:1	2008:2	2008:3	2008:4	2009:1	2009:2	2009:3	2009:4	2007	2008	2009
GDP at market prices (2002 $ millions)	1,301,284	1,312,257	1,320,389	1,328,572	1,336,326	1,348,084	1,358,332	1,368,473	1,379,397	1,389,333	1,399,271	1,409,212	1,315,626	1,352,804	1,394,303
	1.0	*0.8*	*0.6*	*0.6*	*0.6*	*0.9*	*0.8*	*0.7*	*0.8*	*0.7*	*0.7*	*0.7*	*2.6*	*2.8*	*3.1*
Implicit price deflator—GDP at market prices (2002 = 1.0)	1.150	1.166	1.175	1.184	1.192	1.193	1.199	1.204	1.210	1.216	1.221	1.227	1.169	1.197	1.218
	1.6	*1.4*	*0.7*	*0.8*	*0.6*	*0.1*	*0.4*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*3.6*	*2.4*	*1.8*
U.S. GDP at market prices (2000 $ billions)	11,413	11,524	11,587	11,637	11,695	11,761	11,842	11,932	12,051	12,166	12,275	12,386	11,540	11,808	12,220
	0.2	*1.0*	*0.5*	*0.4*	*0.5*	*0.6*	*0.7*	*0.8*	*1.0*	*1.0*	*0.9*	*0.9*	*1.9*	*2.3*	*3.5*
Consumer Price Index (2002 = 1.0)	1.102	1.119	1.120	1.127	1.133	1.139	1.144	1.150	1.155	1.161	1.166	1.172	1.117	1.142	1.164
	0.9	*1.5*	*0.1*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*2.4*	*2.2*	*1.9*
Total employment (000s)	16,757	16,811	16,870	16,924	16,981	17,038	17,096	17,155	17,216	17,272	17,326	17,377	16,841	17,067	17,298
Unemployment rate	*6.1*	*6.1*	*6.0*	*6.0*	*6.0*	*5.9*	*5.9*	*5.9*	*5.8*	*5.8*	*5.8*	*5.8*	*6.1*	*5.9*	*5.8*
Private non-farm average hourly earnings	24.84	24.65	24.82	24.99	25.19	25.38	25.55	25.73	25.91	26.09	26.28	26.47	24.82	25.46	26.19
	1.2	*–0.7*	*0.7*	*0.7*	*0.8*	*0.8*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*3.0*	*2.6*	*2.9*
Disposable income (2002 $ millions)	814,678	816,615	827,537	832,228	840,123	845,546	850,985	856,556	866,246	871,658	877,141	882,572	822,765	848,302	874,404
	1.3	*0.2*	*1.3*	*0.6*	*0.9*	*0.6*	*0.6*	*0.7*	*1.1*	*0.6*	*0.6*	*0.6*	*3.9*	*3.1*	*3.1*
Private non-farm productivity (2002 $ thousands)	46.41	46.10	46.15	46.34	46.52	46.75	46.95	47.14	47.34	47.54	47.75	47.96	46.25	46.84	47.65
	0.2	*–0.7*	*0.1*	*0.4*	*0.4*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.1*	*1.3*	*1.7*
Federal government balance ($ millions)	14,924	15,004	21,430	22,105	20,631	22,197	23,982	25,814	23,744	21,922	23,576	25,160	18,366	23,156	23,600
Corporate profits before taxes ($ millions)	205,872	208,244	209,461	218,698	222,862	220,919	224,636	229,435	233,682	237,170	240,693	244,332	210,569	224,463	238,969
	2.2	*1.2*	*0.6*	*4.4*	*1.9*	*–0.9*	*1.7*	*2.1*	*1.9*	*1.5*	*1.5*	*1.5*	*5.9*	*6.6*	*6.5*
Housing starts (000s units)	222	226	218	206	198	197	195	194	193	192	192	191	218	196	192
Prime rate	6.00	6.00	6.21	6.25	6.25	6.25	6.25	6.33	6.71	6.75	6.75	6.75	6.11	6.27	6.74
Cdn. 3-month Treasury bill rate	4.17	4.29	4.24	4.35	4.36	4.36	4.36	4.44	4.82	4.85	4.85	4.85	4.26	4.38	4.84
U.S. 3-month Treasury bill rate	5.12	4.87	4.96	4.63	4.56	4.53	4.51	4.53	4.79	4.87	4.87	4.87	4.89	4.53	4.85
Exchange rate (C$/US$)	0.854	0.911	0.948	0.949	0.954	0.959	0.962	0.964	0.962	0.960	0.958	0.956	0.915	0.960	0.959
U.S. federal funds rate	5.26	5.25	5.21	4.85	4.75	4.75	4.75	4.79	5.15	5.25	5.25	5.25	5.14	4.76	5.22
Merchandise terms of trade	1.181	1.212	1.218	1.230	1.239	1.226	1.226	1.229	1.231	1.233	1.235	1.236	1.210	1.230	1.234
Current account balance ($ millions)	24,452	33,448	37,121	41,281	41,613	38,894	39,027	40,084	41,124	42,073	42,938	44,076	34,075	39,904	42,553

White area represents forecast data.
All data are seasonally adjusted at annual rates, excluding interest rates, indexes and exchange rates.
Private non-farm productivity is the average output (000s of 2002 dollars) per person-hour in all industries, excluding agriculture, non-commercial services and public administration and defence.
Private non-farm average hourly earnings is the weighted average of average weekly wages and salaries in the other primary, manufacturing, construction and services industries divided by the corresponding average weekly hours. The weights employed are each industry's share of total non-farm employment.
Sources: The Conference Board of Canada; Statistics Canada; Bank of Canada; Canada Mortgage and Housing Corporation.

Attachment 12.2

TERASEN GAS INC.
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
($000)

Line No.	Particulars	Account	Fcst Mid-Year 2006	Balance 12/31/2005	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2006	Mid-Year Average 2006	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Deferred Interest	#17904	$ (1,611)	$ (2,093)	$ 152	$ (50)	$ 102	$ 1,719	$ -	$ (272)	$ (1,183)	$ 428
2												
3	NGV Conversion Grants	#17977	109	151	72	(24)	48	(55)	-	144	148	39
4												
5	2003 Revenue Requirement	#17989	110	142	-	-	-	(64)	-	78	110	-
6	2004-2007 Revenue Requirements	#17952	62	73	-	-	-	(23)	-	50	62	-
7	Future Revenue Requirements	#18160	-	-	24	(8)	16	-	-	16	8	8
8												
9	Demand Side Management 1998-2002	#17916	1,649	1,006	1,169	(386)	783	(654)	-	1,135	1,071	(578)
10	Demand Side Management DRIA	#17961	(73)	(145)	-	-	-	145	-	-	(73)	-
11												
12	Property Tax Deferral	#17915	40	(196)	(901)	297	(604)	337	-	(463)	(330)	(370)
13	M.C.R.A. [1]	#17926	(15,997)	(31,993)	(2,600)	858	(1,742)	-	33,735	-	(15,997)	-
14	C.C.R.A. [1]	#18137	12,588	25,175	160,000	(52,800)	107,200	-	(132,375)	-	12,588	-
15	C.C.R.A./M.C.R.A. Interest	#17973	(852)	(1,368)	(1,750)	578	(1,173)	-	572	(1,969)	(1,669)	(817)
16												
17	RSAM [1]	#17927	32,057	38,516	-	-	-	-	(12,919)	25,597	32,057	-
18	RSAM Interest	#17999	319	357	474	(156)	318	-	(62)	613	485	166
19												
20	Revelstoke Propane Cost	#27902	(13)	209	(452)	149	(303)	-	-	(94)	58	71
21												
22	Coastal Facilities											
23	- Extraordinary Plant Loss - Lochburn	#17998	51	119	2	-	2	(27)	-	94	107	56
24												
25	BCUC Levies	#18149	54	118	(352)	116	(236)	(108)	-	(226)	(54)	(108)
26	OSC Compliance Certification Costs	#18148	-	4	235	(78)	157	(250)	-	(89)	(43)	(43)
27												
28	2005 BC Tax Rate Reduction Deferral	#17940	(365)	(750)	-	-	-	729	-	(21)	(386)	(21)
29	2006 LCT Elimination	#18502	-	-	(3,103)	-	(3,103)	-	-	(3,103)	(1,552)	(1,552)
30												
31												
32	Vehicle Lease Deferral	#17941	791	1,033	-	-	-	(316)	-	717	875	84
33												
34	ROE Hearing 2005	#17985	331	227	331	(109)	222	-	-	449	338	7

TERASEN GAS INC.
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
($000)

Line No.	Particulars	Account	Fcst Mid-Year 2006	Balance 12/31/2005	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2006	Mid-Year Average 2006	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
35	Earnings Sharing Mechanism	#17982	$ (441)	$ (882)	$ (10,520)	$ 3,472	$ (7,048)	$ -	$ 4,817	$ (3,113)	$ (1,998)	$ (1,557)
36												
37	NGV Compression Equip. Recovery	#17992	870	994	-	-	-	(248)	-	746	870	-
38												
39	Overheads Change - Income Tax Refund	#17995	(209)	(278)	-	-	-	139	-	(139)	(209)	-
40	CIAOC Software Tax Savings/OH Change	#17995	(1,211)	(1,615)	-	-	-	808	-	(807)	(1,211)	-
41	Bad Debt Allowance for Rates 14 & 14A	#17949	40	36	21	(7)	14	-	-	50	43	3
42	Other Post Employment Benefits	#17991/93	(17,817)	(16,444)	(7,120)	2,350	(4,770)	-	-	(21,214)	(18,829)	(1,012)
43												
44	Deferred 2000 SCP Cost of Service	#17997	94	126		-	-	(64)	-	62	94	-
45	SCP Net Mitigation Revenues	#17912	(90)	(776)	(5,250)	1,733	(3,518)	484	-	(3,810)	(2,293)	(2,203)
46	SCP West to East Transmission	#17913	211	495	-	-	-	(306)	-	189	342	131
47	SCP-PG&E Contract Cancellation	#17936	2,320	2,651	-	-	-	(663)	-	1,988	2,320	-
48	SCP Provincial Sales Tax Reassessment	#18504	-	-	10,029	-	10,029	-	-	10,029	5,015	5,015
49												
50												
51	CCT Deferral	#17924	(199)	(265)	-	-	-	132	-	(133)	(199)	-
52	CCT Assessment	#17929	436	247	247	(82)	165	(251)	-	161	204	(232)
53												
54	Pension Variance	#17946	(12)	232	(2,688)		(2,688)	24	-	(2,432)	(1,100)	(1,088)
55	Insurance Variance	#17947	(132)	(284)	(273)	90	(183)	262	-	(205)	(245)	(113)
56												
57												
58												
59												
60	**Total Deferred Charges in Rate Base**		$ 13,110	$ 14,822	$ 137,747	$ (44,057)	$ 93,690	$ 1,750	$ (106,232)	$ 4,028	$ 9,424	$ (3,686)

[1] *All balances pertaining to the CCRA, MCRA, and RSAM are based on those as submitted and approved per the 2006 Revenue Requirement Application.*

TERASEN GAS (SQUAMISH) INC.
SCHEDULE OF DEFERRED CHARGES

Deferred Charges	Original Cost	Balance to be Amortized 01/01/2006	Gross Additions / (Deductions)	Less Tax	Net Additions / (Deductions)	Amortization	Balance to be Amortized 12/31/2006
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Deferred Propane Purchase Costs (see page 34a)		($38,030)	$38,030	$0	$38,030	$0	$0
TOTAL DEFERRED CHARGES		($38,030)	$38,030	$0	$38,030	$0	$0

Tab 1
Page 25 (a)

Attachment 18.3

TERASEN GAS INC.
ANNUAL REVIEW - 2007
OPERATING AND MAINTENANCE EXPENSES
By BCUC Account

BCUC No.	Particulars	Approved 2007	Projected 2007	Variance 2007
	Operating			
100-11	Distribution Supervision	10,392	10,184	(209)
100-10	**Distribution - Supervision**	10,392	10,184	(209)
100-21	Operation Centre - Distribution	7,187	7,028	(158)
100-22	Asset Management - Distribution	1,040	1,051	11
100-23	Preventative Maintenance - Distribution	1,676	1,693	17
100-24	Distribution Operations - General	4,487	4,758	271
100-25	Meter Exchanges	1,892	1,911	19
100-26	Emergency Management	6,083	7,106	1,024
100-20	**Distribution - Operation**	**22,364**	**23,547**	1,183
100-31	Distribution Corrective - Meters	977	1,083	106
100-32	Distribution Corrective - Propane	6	6	0
100-33	Distribution Corrective - Leak Repair	588	594	6
100-34	Distribution Corrective - Stations	457	462	5
100-35	Distribution Corrective - General	389	393	4
100-30	**Distribution - Maintenance**	**2,417**	**2,537**	120
100	**DISTRIBUTION**	**35,173**	**36,268**	**1,095**
200-11	Transmission Supervision	2,172	2,255	83
200-10	**Transmission - Supervision**	**2,172**	**2,255**	83
200-21	Pipeline Operation	2,002	2,123	121
200-22	Right of Way	1,288	1,405	117
200-23	Compression	1,729	1,747	18
200-24	Gas Control	2,572	2,271	(301)
200-25	Transmission Pipeline Integrity Project (TPIP)	5,682	3,270	(2,412)
200-20	**Transmission - Operation**	**13,274**	**10,816**	**(2,458)**
200-31	Pipeline - Maintenance	217	219	2
200-32	Compression - Maintenance	163	165	2
200-33	TPIP - Maintenance	380	384	4
200-30	**Transmission - Maintenance**	**760**	**768**	8
200	**TRANSMISSION**	**16,207**	**13,839**	**(2,367)**
300-11	LNG Plant Operations	679	686	7
300-10	**LNG - Plant Operation**	**679**	**686**	**7**
300-21	LNG Plant Maintenance	382	386	4
300-20	**LNG - Plant Maintenance**	**382**	**386**	**4**
300	**LNG Plant Operations**	**1,061**	**1,072**	**11**
400-11	Measurement Operations	3,931	3,971	40
400-10	**Measurement - Operation**	**3,931**	**3,971**	**40**
400-21	Measurement Maintenance	-	-	-
400-20	**Measurement - Maintenance**	**-**	**-**	-
400	**MEASUREMENT**	**3,931**	**3,971**	**40**
500-10	**Faciliities Management**	**5,546**	**5,602**	**56**
500-20	**Shops & Stores**	**3,761**	**3,799**	**38**
500-30	**Operations Engineering**	**5,475**	**5,530**	**55**
500-40	**Property Services**	**996**	**1,006**	**10**
500-50	**System Integrity**	**1,901**	**1,920**	**19**
500-60	**Environmental Health & Safety**	**1,478**	**1,422**	**(56)**
500-70	**Operations Governance**	**1,626**	**1,588**	**(38)**
500	**GENERAL OPERATION**	**20,783**	**20,868**	**85**
		-	-	-
	Total Operating	**77,154**	**76,018**	**(1,136)**
				-

TERASEN GAS INC.
ANNUAL REVIEW - 2007
OPERATING AND MAINTENANCE EXPENSES
By BCUC Account

BCUC No.	Particulars	Approved 2007	Projected 2007	Variance 2007
	General & Administration			-
				-
600-10	**Energy Efficiency**	**1,752**	**1,770**	**18**
600-20	**Marketing - Supervision**	**668**	**675**	**7**
600-30	**Corporate & Marketing Communications**	**2,066**	**2,087**	**21**
600-40	**Marketing Planning & Development**	**752**	**759**	**8**
600	**MARKETING**	**5,238**	**5,291**	**53**
700-10	**Customer Care - Supervision**	**1,014**	**893**	**(120)**
700-20	**Customer Contact - ABSU contract**	**49,339**	**49,724**	**385**
700-30	**Bad Debt Management and Administration**	**6,206**	**5,530**	**(676)**
700-40	**Customer Management & Sales**	**2,730**	**3,303**	**573**
700	**CUSTOMER CARE**	**59,290**	**59,450**	**161**
800-10	**Business & IT Services - Supervision**	**1,179**	**1,191**	**12**
800-20	**Application Management**	**8,203**	**8,286**	**83**
800-30	**Infrastructure Management**	**6,426**	**6,491**	**65**
800-40	**Procurement Services**	**810**	**818**	**8**
800	**BUSINESS & INFORMATION TECH SERVICES**	**16,618**	**16,786**	**168**
900-11	Administration & General	4,666	6,083	1,418
900-12	Insurance	5,479	5,534	56
900-13	Finance and Regulatory Affairs	8,985	9,122	137
900-14	Shared Services Agreement	4,315	4,359	44
900-10	**Corporate Administration**	**23,444**	**25,098**	**1,654**
900-20	**Forecasting**	**1,462**	**1,200**	**(262)**
900-31	Community Relations	1,397	1,411	14
900-30	**Public Affairs**	**1,397**	**1,411**	**14**
900-40	**Business Development**	**1,437**	**1,332**	**(105)**
900-50	**Human Resource**	**4,561**	**4,700**	**139**
900-60	**Other Post Employment Benefits**	**8,860**	**8,950**	**90**
900	**ADMINISTRATION & GENERAL**	**41,162**	**42,691**	**1,529**
				-
	TOTAL GENERAL AND ADMINISTRATION	**122,308**	**124,219**	**1,911**
				-
	TOTAL OPERATING & GENERAL ADMINISTATION	**199,462**	**200,237**	**775**
				-
	Less : Stock Related Compensation	0	(1,249)	(1,249)
				-
	Total Formula Gross O&M (including Fort Nelson)	**199,462**	**198,988**	**(474)**
				-
	Less:			-
	Capitalized Overhead	(27,535)	(27,535)	-
66105 CC2	Vehicle Lease	(2,016)	(2,011)	5
	Fort Nelson	(639)	(637)	2
				-
	Total Formula Utility O&M	**169,272**	**168,805**	**(467)**
	Formula O&M	**199,462**	**198,988**	**(474)**

TERASEN GAS INC.
OPERATING AND MAINTENANCE EXPENSES
Resource View

Cost Element	Approved 2007	Projected 2007	Variance 2007
M&E Expenses	45,594	46,864	1,269
COPE Expenses	25,508	25,438	(70)
IBEW Expenses	20,541	21,502	961
Total Labour Expenses	**91,643**	**93,803**	**2,160**
Vehicle Expenses	5,183	5,279	96
Employee Expenses	3,934	3,949	15
Materials	5,198	5,142	(56)
Office Furnishing & Equipment	118	119	1
Computer Expenses	8,152	8,235	83
Fees & Admin, Promotion & Advertising	29,877	29,286	(591)
Contractors Expenses	59,396	58,832	(564)
Facilities	12,357	12,155	(202)
Recoveries & Revenue	(16,396)	(16,562)	(166)
Total Non-Labour Expenses	**107,819**	**106,435**	**(1,384)**
Less: Stock Related Compensation	-	(1,249)	(1,249)
Total Formula Gross O&M Expenses	**199,462**	**198,988**	**(474)**
Less:			
Capitalized Overhead	(27,535)	(27,535)	-
Vehicle Lease Reclass	(2,016)	(2,011)	5
Fort Nelson	(639)	(637)	2
Formula Utility O&M Expenses (excl Fort Nelson)	**169,272**	**168,805**	**(467)**
Formula Gross O&M	199462	198988	-474

Attachment 18.6.1

TERASEN GAS INC.
COMPENSATION DATA SUMMARY
($000)

Line No.	Particulars	Reference	2005 Normal	Year Ended 12/31/2006 Actual	Normalization	Normal	Difference	Reasons for Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Number of Employees							
2	Executive Officers		7	7	-	7	(0)	
3	Other Management & Exempt Employees		245	241	-	241	(4)	
4	COPE		424	416	-	416	(7)	
5	IBEW		446	421	-	421	(25)	Please refer to Page 33 - Difference Analysis
6								
7	Total		1,122	1,086	-	1,086	(37)	
8								
9								
10	Total Compensation							
11	Executive Officers		$ 2,353	$ 3,223	$ -	$ 3,223	$ 870	Please refer to Page 33 - Difference Analysis
12	Other Management & Exempt Employees		22,099	21,846	-	21,846	(253)	Please refer to Page 33 - Difference Analysis
13	COPE		25,702	24,105	-	24,105	(1,597)	Please refer to Page 33 - Difference Analysis
14	IBEW		30,212	28,210	-	28,210	(2,002)	Please refer to Page 33 - Difference Analysis
15								
16	Total		$ 80,366	$ 77,384	$ -	$ 77,384	$ (2,982)	
17								
18								
19	Average Per Employee							
20	Executive Officers		$ 328.2	$ 460.4	$ -	$ 460.4	$ 132.3	Please refer to Page 33 - Difference Analysis
21	Other Management & Exempt Employees		90.3	90.7	-	90.7	0.4	
22	COPE		60.6	57.9	-	57.9	(2.7)	
23	IBEW		67.7	66.9	-	66.9	(0.7)	
24								
25	Average		$ 72.5	$ 71.3	$ -	$ 71.3	$ (1.2)	
26								
27								
28	Total Compensation includes the following for Fort Nelson							
29	Management & Exempt Employees		$ 108	$ 101	$ -	$ 101	$ (7)	
30	COPE		36	14	-	14	(22)	
31	IBEW		165	173	-	173	8	
32								
33	Total		$ 309	$ 288	$ -	$ 288	$ (21)	

Note that all amounts reported are on an accrual basis to be consistent with utility income presentation

TERASEN GAS INC.

DIFFERENCE ANALYSIS

Explanation of Variances

"Number of Employees" is derived from the average number of full time workers plus the employee-equivalent number of temporary workers. As such, it is an indicator of labour hours required to perform the required tasks.

Compensation varies depending on many factors, including general increases in wage and salary levels, promotions and reclassifications, annual step increases (COPE & IBEW), individual performance, and variations in the actual mix of employees at different job levels.

Number of Employees

The number of IBEW employees decreased by 6% from 446 employees in 2005, to 421 employees in 2006. The number of IBEW employees has been declining for the past few years as there was a retirement incentive available to these employees, and there had been no significant replacement hiring for a few years.

Total Compensation

Compensation expensed to Executive Officers increased by $870,000 (or 37%) in 2006 relative to that in 2005. The 2006 – 2009 deferred retention arrangements for executives and senior managers replaced the previous mid and long term incentive plans. Compensation paid to Other Management and Exempt employees decreased by $253,000, or 1% in 2006, due to fewer Other Management and Exempt staff being employed. The $1.6 million, or 6% decrease in compensation paid to COPE members during 2006 was the result of there being fewer COPE employees in 2006. The $2.0 million or 7% reduction in compensation paid to IBEW members resulted from fewer IBEW employees, as mentioned above.

Average per Employee

Average salary paid to Executive Officers increased by $132,300 in 2006 relative to that expensed in 2005, salary adjustments and changes to deferred retention arrangements were made for the Executive Officers and senior managers. For Other Management and Exempt employees, average compensation remained virtually the same as in 2005.

Attachment 53.1

Location	Program Name	Description		Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	2007 Total	CO2	Measure Savings (CO2)
	ENERGY * Qualified Heating Upgrade	Applications (# processed)		0	562	697	1,067	13	65	7	0	-			455	2,866		
	$50 for each VSM	Installations (# completed)		139	85	135	-	-		-	-							
		Incentives ($)	$150	$ -	$ 84,300	$ 104,550	$ 160,050	$ 1,950	$ 9,750	$ 1,050	$ -	$ -	$ -	$ -	$ 113,750	$ 475,400		
		Administration	$45	$ -	$ 25,290	$ 31,365	$ 48,015	$ 585	$ 2,925	$ 315	$ -	$ -	$ -	$ -	$ 20,475	$ 128,970		
		Gross Savings (GJ)	13.8	-	7,756	9,619	14,725	179	897	97	-	-	-	-	6,279	39,551		
		Net Savings (GJ)	50%	-	3,878	4,809	7,362	90	449	48	-	-	-	-	3,140	19,775	2,005	40,097
	ENERGY * Qualified Heating No VSM	Applications (# processed)			250	368	586	9	34	2	6	-	-	-	195	1,450		
		Installations (# completed)		295	201	323	-	-	-	-		-	-	-	-	819		
		Incentives ($)	$100	$ -	$ 25,000	$ 36,800	$ 58,600	$ 900	$ 3,400	$ 200	$ 600	$ -	$ -	$ -	$ 48,750	$ 174,250		
		Administration	$45	$ -	$ 11,250	$ 16,560	$ 26,370	$ 405	$ 1,530	$ 90	$ 270	$ -	$ -	$ -	$ 8,775	$ 65,250		
		Gross Savings (GJ)	13.8	-	3,450	5,078	8,087	124	469	28	83	-	-	-	2,691	20,010		
		Net Savings (GJ)	50%	-	1,725	2,539	4,043	62	235	14	41	-	-	-	1,346	10,005	1,014	20,286
	Residential New Construction (NEW)	Applications (# processed)		0	0	0	0	0	0	0	0	0	0	0	2,981	2,981		
	$250 for each ENERGY STAR qualified space heating system	Installations (# completed)														-		
		Incentives ($)	$250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 745,250	$ 745,250		
		Administration ($)	$45	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 134,145	$ 134,145		
		Gross Savings (GJ)	9.1	-	-	-	-	-	-	-	-	-	-	-	27,127	27,127		
		Net Savings (GJ)	80%	-	-	-	-	-	-	-	-	-	-	-	21,702	21,702	1,375	27,501
	Commercial Boiler Upgrade	Applications (# processed)													20	20		
		Installations (# completed)														0		
		Incentives ($)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 297,542	$ 297,542		
		Administration ($)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,000	$ 90,000		
		Gross Savings (GJ)		-	-	-	-	-	-	-	-	-	-	-	14,650	14,650		
		Net Savings (GJ)	82%	-	-	-	-	-	-	-	-	-	-	-	12,013	12,013	743	14,853
	Commercial Energy Assessments	Applications (# processed)													100	100		
		Installations (# completed)														0		
		Incentives ($)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
		Administration ($)	$800	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 80,000	$ 80,000		
		Gross Savings (GJ)	600	-	-	-	-	-	-	-	-	-	-	-	60,000	60,000		
		Net Savings (GJ)	75%	-	-	-	-	-	-	-	-	-	-	-	45,000	45,000	3,041	45,621
	Destination Conservation	Applications (# processed)													44	44		
		Installations (# completed)														0		
		Incentives ($)	1500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,000	$ 66,000		
		Administration ($)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
		Gross Savings (GJ)	113	-	-	-	-	-	-	-	-	-	-	-	4,972	4,972		
		Net Savings (GJ)	100%	-	-	-	-	-	-	-	-	-	-	-	4,972	4,972	252	756
		Applications (# processed)		-	812	1,065	1,653	22	99	9	6	-	-	-	3,795	7,461		
		Installations (# completed)		434	286	458	-	-	-	-	-	-	-	-	-	1,178		
	TOTAL TGI	Incentives ($)		$ -	$ 109,300	$ 141,350	$ 218,650	$ 2,850	$ 13,150	$ 1,250	$ 600	$ -	$ -	$ -	$ 1,271,292	$ 1,758,442		
		Administration ($)		$ -	$ 36,540	$ 47,925	$ 74,385	$ 990	$ 4,455	$ 405	$ 270	$ -	$ -	$ -	$ 333,395	$ 498,365		
		Total Cost ($)		$ -	$ 145,840	$ 189,275	$ 293,035	$ 3,840	$ 17,605	$ 1,655	$ 870	$ -	$ -	$ -	$ 1,604,687	$ 2,256,807		
		Gross Savings (GJ)		-	11,206	14,697	22,811	304	1,366	124	83	-	-	-	115,720	166,310		
		Net Savings (GJ)		-	5,603	7,349	11,406	152	683	62	41	-	-	-	88,172	113,467	8,430	149,114

	PROGRAM												NET PRESENT VALUE					ECONOMIC TESTS				PARAMETERS			
	COSTS ($000)								SAVINGS (GJ)			LIFE	Levelized Cost	Utility Benefits	Benefit/ Cost Ratio	Participant Savings	Program Savings						Utility	Customer	
	Utility			Participants								Years	($/GJ)	($'000s)		($'000s)	(GJ)					Discount Rate	a	b	
	Incentives	Administration	Total	# of Participants	Cost ($000)	Total	% Utility	% Customer	Gross	Net-to-gross	Net							Utility	Participant	Rate Impact	Total Resource Cost	Unit Cost NPV			Tariff
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S		T	U	V	W	X	X
Calculation	Input (program)	Input (program)	B+C	Input (program)	Input (program)	D+F	F/G	D/G	Input (program)	Input (program)	J x K	Input (program)	G / R	L x X	O / G	J x Y	PV(a,M,L)	O / D	Q / F	O /((J x Y)+D)	O / (G + pe +r)		NPV(a,ts)	PV(b,L,Xc)	
																		Net Savings		Gross Savings			11.52		
TGI																							5.90%	10.00%	
RESIDENTIAL:																									
Existing Housing																									
ENERGY * Qualified Heating Upgrade	475	129	604	2,866	1,244	1,849	33%	67%	39,551	50%	19,775	20	8.08	$2,634	1.43	$3,903	228,675	4.4	3.1	0.58	1.39		133.21	98.67	11.590
ENERGY * Qualified Heating No VSM	174	65	240	1,450	696	935	26%	74%	20,010	50%	10,005	20	8.08	$1,333	1.43	$1,974	115,694	5.6	2.8	0.60	1.39		133.21	98.67	11.590
New Housing																									
Residential New Construction (NEW)	745	134	879	2,981	745	1,625	54%	46%	27,127	80%	21,702	20	6.47	$2,891	1.78	$2,677	250,950	3.3	3.6	0.81	1.73		133.21	98.67	11.590
Residential Total	1,395	328	1,723	7,297	2,685	4,408	39%	61%	86,688		51,482		7.41	$6,858	1.56	$8,554	595,319	4.0	3.2	0.67	1.52				
COMMERCIAL:																									
Large Offices, Commercial Sites																									
Commercial Boiler Upgrade	298	90	388	20	803	1,191	33%	67%	14,650	82%	12,013	25	7.68	$1,786	1.50	$1,524	155,041	4.6	1.9	0.93	1.47		148.67	104.02	11.460
Commercial Energy Assessments	0	80	80	100	1,500	1,580	5%	95%	60,000	75%	45,000	15	3.59	$5,068	3.21	$5,230	439,921	63.3	3.5	0.95	3.03		112.62	87.17	11.460
Institutions																									
Destination Conservation	66	0	66	44	22	88	75%	25%	4,972	100%	4,972	3	7	$153	1.74	$142	13,315	2.3	6.4	0.74	1.56		30.85	28.50	11.460
Commercial Total	298	170	468	120	2,303	2,771	17%	83%	74,650		57,013		4.56	$6,854	2.47	$6,754	608,277	14.7	2.9	0.95	2.38				
TGI Total	1,692	498	2,191	7,417	4,988	7,179	31%	69%	161,338		108,495		5.96	13,712	1.91	15,308	1,203,596	6.3	3.1	0.78	1.85				
Planning and Evaluation			219																						
Net Expenditure			2,410																						

Program name	Participants	Rate Class	Annual Savings/Unit		Measure Life	Free Riders	Incentive	Participant Costs		Program Costs	Total NG Savings	TRC	TRC Net Benefit
2007 Furnace Upgrade	8,000	Residential	13.80		25	50%	150	600		250,000	2,760,000		
2007 New Construction Heating Upgrade	1,500	Residential	9.1		25	20%	150	500		300,000	475,875		
2007 Efficient Boiler Program	20	Commercial	1,379		25	18%	12,000	1,100,739		250,000	4,481,750		
2007 Assessment	100	Commercial						15,000					
2007 Destination Conservation	44	Commercial	113		3	0%	-	2,000		45,000	4,972		

Program	Program Benefits ($000)	Program Costs ($000)	Evaluation ($000)	Customer Costs ($000)	Total ($000)	TRC Net Benefit ($000)	B/C Ratio
TGI							
RESIDENTIAL:							
Existing Housing							
ENERGY * Qualified Heating Upgrade	2,634	604	40	1,244	1,889	746	1.39
ENERGY * Qualified Heating No VSM	1,333	240	20	696	955	377	1.39
New Housing							
Residential New Construction (NEW)	2,891	879	44	745	1,668	1,222	1.73
Residential Total	6,858	1,723	104	2,685	4,512	2,346	1.52
COMMERCIAL:							
Large Offices, Commercial Sites							
Commercial Boiler Upgrade	1,786	388	24	803	1,215	571	1.47
Commercial Energy Assessments	5,068	80	91	1,500	1,671	3,397	3.03
Institutions							
Destination Conservation	153	66	10	22	98	55	1.56
Commercial Total	6,854	468	115	2,303	2,886	3,968	2.38
TGI Total	**13,712**	**2,191**	**219**	**4,988**	**7,398**	**6,314**	**1.85**

	RESOURCE COST ($'000)								BENEFIT/COST				
	UTILITY						CUSTOMER	TOTAL					Measure
Sector/Program	**Direct Incentives**	**Direct Information**	**Program Labour**	**Program Evaluation**	**Research Adm & OH**	**Total**			**Participant**	**Total Resource**	**Rate Payer**	**Levelized Cost**	**Life (Years)**
RESIDENTIAL:													
Existing Housing													
ENERGY * Qualified Heating Upgrade	475		129	40		644	1,244	1,889	3.1	1.39	0.58	8.1	20
ENERGY * Qualified Heating No VSM	174		65	20		260	696	955	2.8	1.39	0.60	8.1	20
New Housing													
Residential New Construction (NEW)	745		134	44		923	745	1,668	3.6	1.73	0.81	6.5	20
Residential Total	1,395	-	328	104	-	1,827	2,685	4,512	3.2	1.52	0.67	7.4	
COMMERCIAL:													
Large Offices, Commercial Sites													
Commercial Boiler Upgrade	298		90	-		388	803	1,191	1.9	1.47	0.93	7.7	25
Commercial Energy Assessments	-		80	24		104	1,500	1,604	3.5	3.03	0.95	3.6	15
Institutions													
Destination Conservation	66		-	-		66	22	88	6.4	1.56	0.74	6.6	3
Commercial Total	298	-	170	24	-	492	2,303	2,795	2.9	2.38		4.6	
TGI Total	1,692	-	498	128	-	2,319	4,988	7,307	3.1	1.85	0.78	6.0	