Terasen Gas

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November 12, 2004

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

Attention: Mr. Robert J. Pellatt, Commission Secretary

Dear Sir:

RE: Terasen Gas Inc. ("Terasen Gas)
2004 – 2007 Performance Based Rate Plan 2004 Annual Review
Terasen Gas Response to Commission Information Request No. 1

Terasen Gas respectfully submits the attached responses to Commission Information Request No. 1.

Twenty hard copies of the attached will be sent to the Commission office by Monday, November 15, 2004.

Yours very truly,

TERASEN GAS INC.

Original signed by Tom Loski

For: Scott A. Thomson

Attachment

cc. Registered Intervenors

1.0 Reference: Section A, Tab 1, Summary, p. 4

1.1 *Please provide the supporting calculations for the line item "Higher Interest Expense" of $1.9 million.*

Response

Supporting calculations for higher interest expense of $1.9 million is as follows:

	Principal	2004 Interest Rate	2005 Interest Rate	Change in Interest Rate	Impact on 2005 Interest Expense
2004 Long Term Debt	$ 1,315,417	7.373%	7.296%	-0.077%	$ (1,013)
2004 Unfunded Debt	225,493	3.250%	4.000%	0.750%	1,691
2005 Net increase to Long Term Debt	51,492		6.387%	6.387%	3,289
2005 Reduction to Unfunded Debt	(51,492)		4.000%	4.000%	(2,060)
Total Interest Change					$ 1,907
Rounded to Nearest Millions					$ 1.9

1.2 *Please provide the supporting calculations for the line item "Higher Rate Base due to Plant Additions" of $4.4 million.*

Response

2005 Rate Base additions, excluding Coastal Facilities	$45,633
Pre-tax 2005 cost component	9.28%
Revenue Requirement impact before working capital	$4,234
Add Working Capital Effect	126
Total Revenue Requirement Impact	$4,360
Rounded to the Nearest Millions	$4.4

2.0 Reference: Section A, Tab 1, p. 6, line 26 and Tab 8, p. 2, line 24, Construction Advances

Please explain the decrease in Construction Advances in 2004 from $750,000 to $415,000 and in 2005 from $750,000 to $2,000.

Response

This decrease is the result of final reviews conducted on pre-1997 construction advances paid by connecting customers on main extension projects. In accordance with the Company's General Terms and Conditions, on-going reviews are required to determine if a refund is payable to customers who have contributed to the extension during the first 5 years after it was built. If the refund is no longer payable to customers, then the amount is transferred from the construction advances account to the contributions in aid of construction account which accumulates non-refundable advances.

3.0 Reference: Section A, Tab 3, p. 11.3, Deferral Charges
TGI 2003 Annual Review, Section A, Tab 3, p. 11.1, line 46

3.1 *The gross addition for post employment deferral charges in 2004 was $5.717 million in the TGI 2003 annual review material while the 2004 projected gross addition has increased to $6.669 million. Please identify the causes for this increase and provide a breakdown of the variances.*

Response

Post employment benefits, like pensions, are determined by the Company's actuarial firm. Based on a preliminary review, the primary cause of the increase is due to a significant increase in medical services plan premiums. Further breakdowns of the causes would likely have to be conducted by our actuaries likely at a significant cost. As post employment benefit expenses are treated as normal O&M under the terms of the negotiated settlement, Terasen Gas is not able to recover increases over and above what the O&M formula provides for.

4.0 Reference: Section A, Tab 3, p. 12, line 18, Other Working Capital Items - Inventories

Please explain the increase of Inventories from $4.1 million (approved 2004) to $6.9 million (forecast 2005). What are the projected Inventories for 2004?

Response

The increase of inventories from $4.1 million in 2004 to $$6.9 million in 2005 is attributable to an increase in material purchases resulting from higher customer additions. Projected year end customer additions in 2004 is 11,412, an increase of 2,808 over the approved 2004 adds of 8,604. For 2005, an additional 10,144 customer additions has been forecasted.

There were also a number of new operations processes that resulted in increased inventory levels.

Projected inventory balance for 2004 is $5.9 million, reflecting recent customer growth. As stated in the above customer add projections, this strong growth is to continue into 2005.

5.0 Reference: Section A, Tab 4, pp. 2-4, Load Forecast – Customer Additions

On page 4 in the Section titled "Customer Additions Forecast," TGI states that "To forecast residential account additions, actual household formation, estimated market share and historical commodity price are statistically linked with actual account additions to model annual account growth on a service area basis."

5.1 *Please confirm that GDP, employment rate and BC Housing starts are not direct inputs into the forecasting model for residential customer additions? If they are, please explain how they are included in the model.*

Response

GDP, employment rate, and BC Housing starts are all variables that are **not** direct inputs into the forecasting model for residential customer additions.

The direct inputs into the forecasting model for residential customer additions are forecasted Household Formation growth rates, Terasen Gas Market Share of New Housing starts and Commodity Prices.

5.2 *If housing starts are not direct inputs into the forecasting model for residential customer additions, please explain how, if at all, forecasts of housing starts are used to adjust the customer additions forecast.*

Response

Housing starts are not used as a direct input to model residential customer additions but instead are used as a "reasonableness" check to validate household formation growth rates. Historically, new housing starts are correlated with household formation growth rates. In the absence of a readily available long-term (i.e. 20 year) housing starts forecast, the readily available household formation projections from BC STATS are used instead.

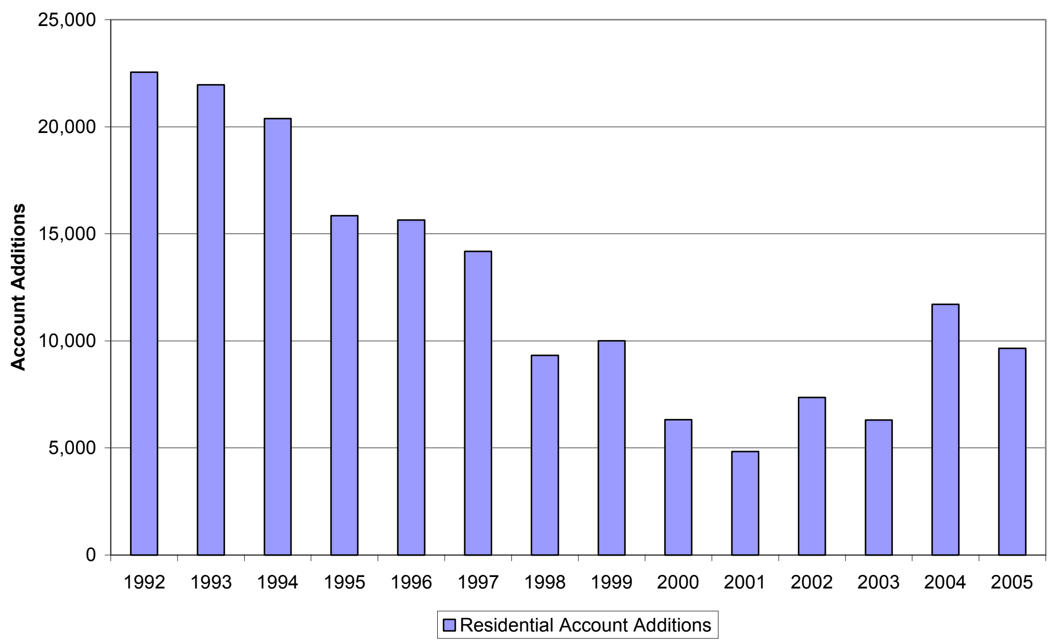
5.3 *Please provide, in a table and graphically, the data for household formation, estimated market share and historical commodity price along with the forecast number of residential additions for each year over the time period used in the model.*

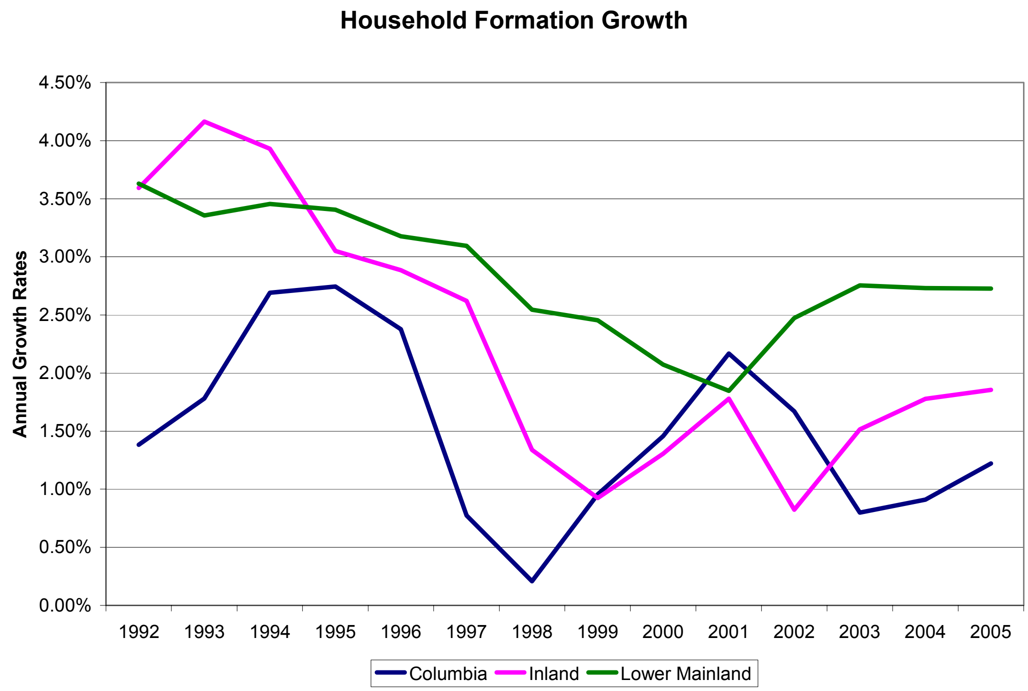
Response

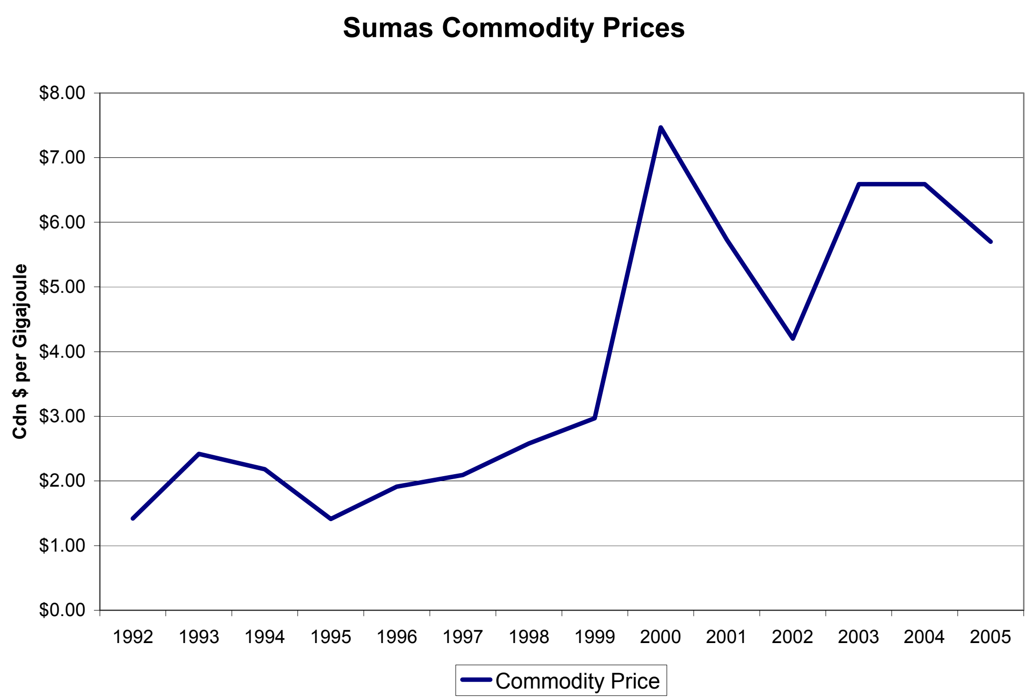
Following are the data inputs used in the residential account additions model.

Year	Household Formation Growth Rate				Market Share	BC GDP Growth	Commodity Price	Res. Acct Additions
	Columbia	Inland	Lower Mainland	Revelstoke				
1992	1.38%	3.59%	3.63%	0.87%	80%	3%	1.42	22,549
1993	1.78%	4.17%	3.36%	1.70%	80%	5%	2.42	21,952
1994	2.69%	3.93%	3.46%	1.88%	80%	3%	2.18	20,381
1995	2.74%	3.05%	3.41%	2.00%	80%	2%	1.41	15,847
1996	2.38%	2.88%	3.18%	2.45%	78%	3%	1.91	15,649
1997	0.77%	2.62%	3.09%	0.34%	73%	3%	2.09	14,180
1998	0.21%	1.34%	2.55%	-2.22%	68%	1%	2.58	9,327
1999	0.96%	0.92%	2.45%	-1.25%	65%	3%	2.97	10,009
2000	1.46%	1.31%	2.07%	0.62%	56%	5%	7.47	6,317
2001	2.17%	1.78%	1.85%	2.34%	56%	0%	5.73	4,835
2002	1.67%	0.82%	2.47%	1.00%	55%	2%	4.20	7,360
2003	0.80%	1.52%	2.75%	1.44%	55%	2%	6.59	6,306
2004	0.91%	1.78%	2.73%	1.37%	54%	3%	6.59	11,711
2005	1.22%	1.86%	2.73%	1.40%	54%	3%	5.70	9,652

Residential Account Additions




Household Formation Growth
Annual Growth Rates
4.50%
4.00%
3.50%
3.00%
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Columbia
Inland
Lower Mainland


Sumas Commodity Prices
Cdn $ per Gigajoule
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1992
1993
1994
1995
1996
1997
1998
1999
2000
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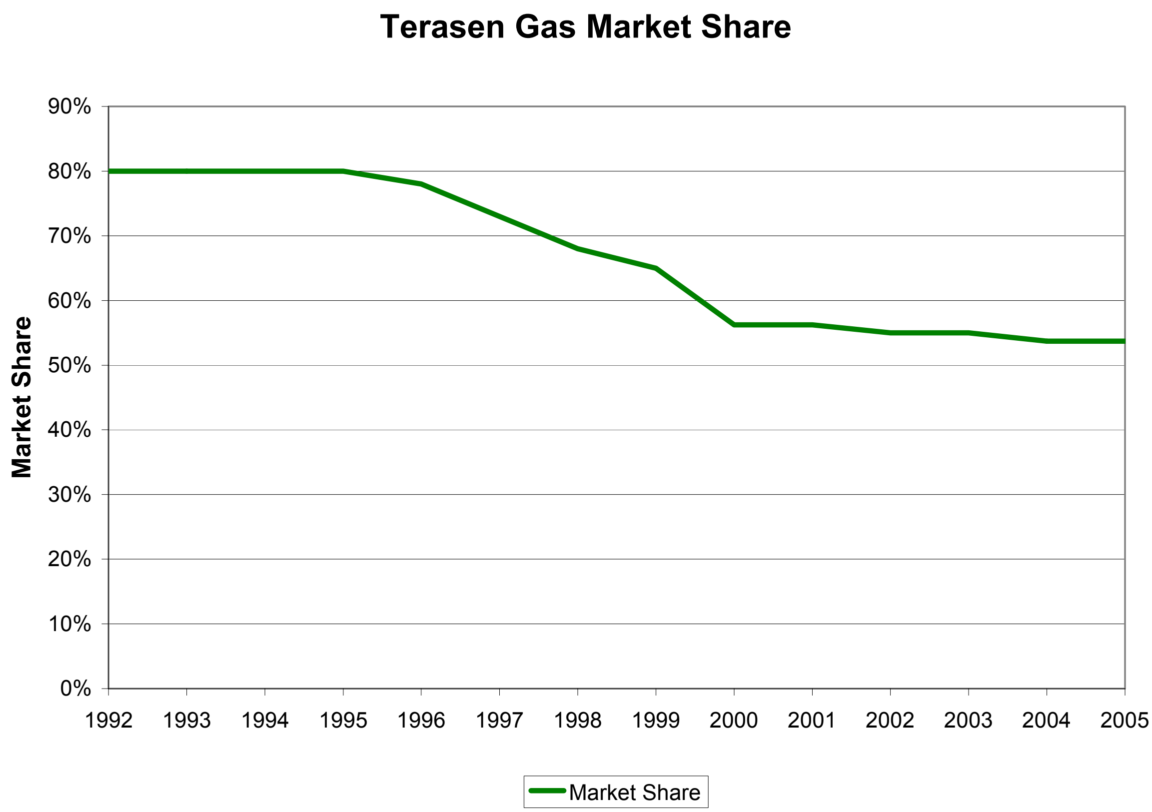
2002
2003
2004
2005
Commodity Price



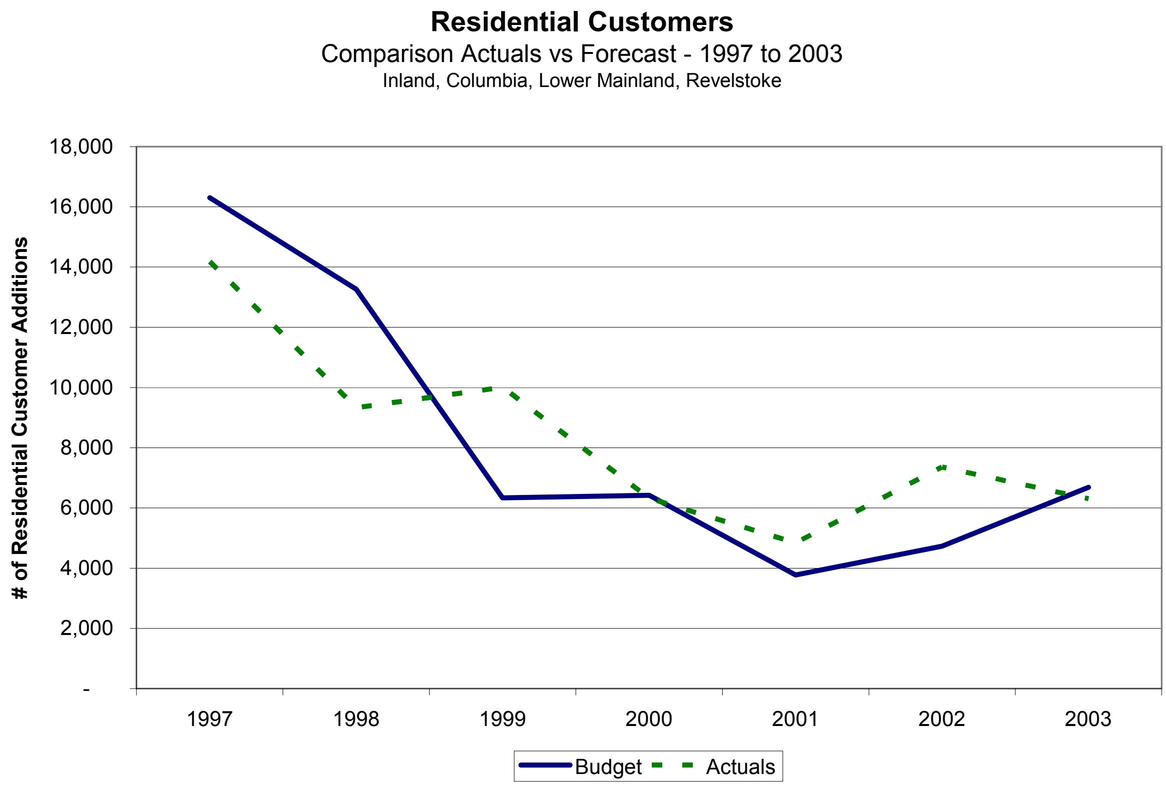
5.4 *Please provide since 1995 to the present, the forecast number of residential additions as compared to the actual number of additions. Please provide the answer both as a table and a graph.*

Response

Residential Customers

	1997	1998	1999	2000	2001	2002	2003	1997 - 2003
Budget	16,300	13,259	6,338	6,421	3,776	4,728	6,687	57,509
Actuals	14,180	9,327	10,009	6,317	4,835	7,360	6,306	58,334
Variance	(2,120)	(3,932)	3,671	(104)	1,059	2,632	(381)	825

Budget is equal to forecast. Data prior to 1997 was not readily available.



Cumulatively, from 1997 to 2003, the total forecast error was +825 (i.e. actual customers recorded higher than forecast) for an error percentage of approximately 1.5%.

5.5 Reference: TGI 2004 Annual Review Filing, Section A, Tab 4, pp. 2-4

5.5.1 *What data is used in developing the forecast for commercial customer additions and how is that data used to create the forecast?*

Response

The data used in developing the commercial customer additions forecast include household formation growth rates, growth in BC Real GDP, and Commodity Price. Commercial Account Growth Rates are statistically linked to Household Formation Growth Rates, BC GDP Growth Rates, and Commodity Prices using the following model:

Acct Growth Rate = β_1(HHF Growth Rate) + β_2(Price) + β_3(BC GDP Growth Rate)

Note: The above model was constrained to pass through the origin, after initial analysis concluded the intercept variable, $\boldsymbol{\beta_0}$, was insignificant.

Once the equation was modeled for each region, the resulting coefficients were used in conjunction with the projected household formation growth rates, projected BC GDP growth rates, and forward commodity prices to calculate the projected commercial account additions.

5.5.2 *Please provide since 1995 to the present, the forecast number of commercial additions as compared to the actual number of additions. Please provide the answer both as a table and a graph.*

Response

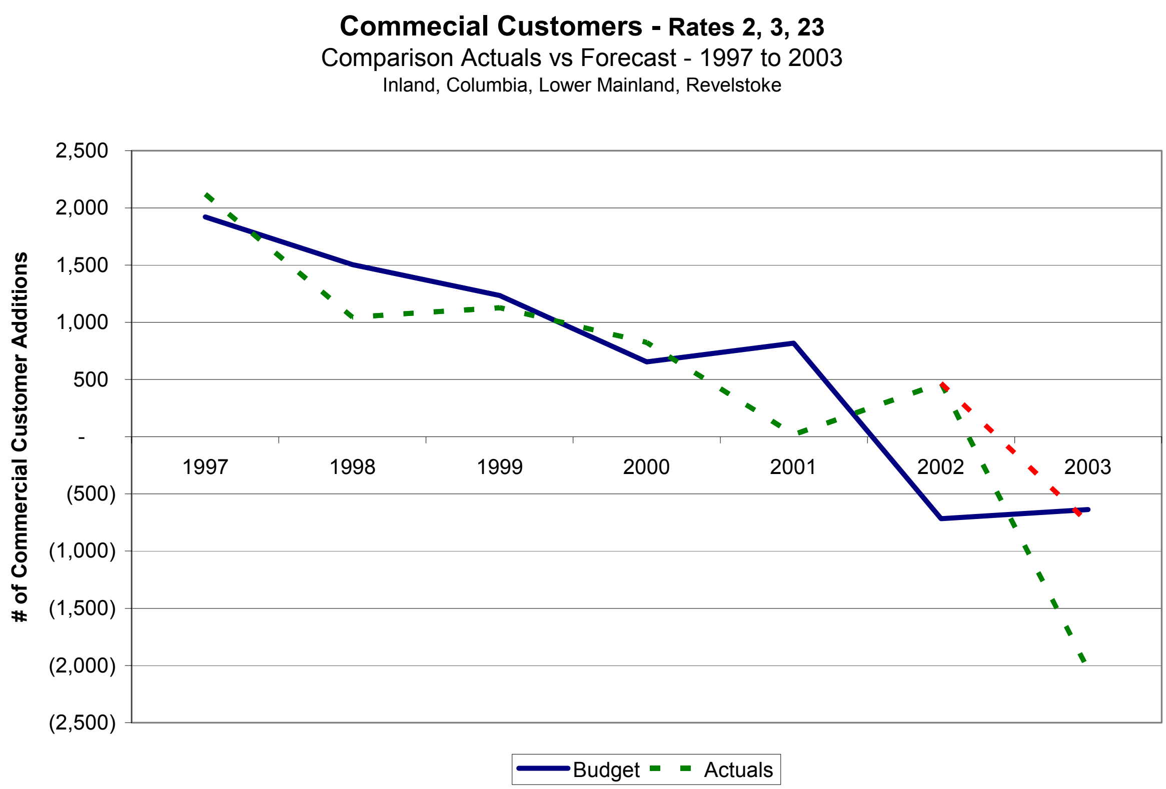
Commercial Customers
Rates 2, 3, 23

	1997	1998	1999	2000	2001	2002	2003	1997 - 2003
Budget	1,921	1,505	1,234	654	818	(717)	(637)	4,778
Actuals	2,120	1,045	1,128	823	19	467	(2,035)	3,567
Variance	199	(460)	(106)	169	(799)	1,184	(1,398)	(1,211)

*** Year 2003 reflects adjustment of 1,283 for 2002 BC Hydro repatriation adjustment**

	1997	1998	1999	2000	2001	2002	2003 *	1997 - 2003
Budget	1,921	1,505	1,234	654	818	(717)	(637)	4,778
Actuals	2,120	1,045	1,128	823	19	467	(752)	4,850
Variance	199	(460)	(106)	169	(799)	1,184	(115)	72

Budget is equal to forecast. Data prior to 1997 was not readily available.



Cumulatively, from 1997 to 2003, the total forecast error was -489 (i.e. actual customers recorded lower than forecast) for an error percentage of approximately 12%.

5.6 Reference: TGI 2004 Annual Review Filing, Section A, Tab 4, p. 5 and TGI 2003 Annual Review Filing, Tab A, Tab 4, p. 4

It appears that the 2001 and 2002 Actual Commercial Customer Additions are different between the 2004 Annual Review Filing and the 2003 Annual Review Filing. Please explain why these two sets of data are not the same.

Response

Historic actual figures in the 2004 Annual Review Filing were sourced from a non-current customer billing file which was subsequently amended. Below is the amended Customer Growth table with the corrected comparative information. The discrepancy only affects historical comparatives and has no impact on both 2004 and 2005 customer projections.

TGI Customer Growth[1]

	2001 ACTUALS	2002 ACTUALS	2003 ACTUALS	2004 PROJECTED	2005 FORECAST
Residential	4,835	7,360	6,306	11,711	9,652
Commercial	19	467	(2,035) [4]	(291)	501
Industrial & Transportation	14	41	16	(8)	(9)
Total Change	**4,868**	**7,868**	**4,287**	**11,412**	**10,144**
Year-Ending Customers	763,361	771,229	775,516	786,928	797,072
Housing Starts[2]	17,234	21,625	24,050	31,700	32,400
Population Growth[3]	0.8%	1.0%	1.4%	1.4%	1.2%

Notes

1. Includes Lower Mainland, Inland, Columbia, & Revelstoke service regions only.
2. Housing Stats forecast for 2004 from CMHC, October 2004.
3. Population Growth Forecast from 2004 BC Stats Provincial Population Forecast - BC Ministry of Finance & Corporate Relations.
4. B.C. Hydro Repatriation adjustment.

6.0 Reference: Section A, Tab 4, pp. 6-7, Load Forecast – Use per Customer

6.1 *Please show more precisely how the 2005 forecast of use per account for the customer classes shown on page 7 of the TGI Annual Review document is derived, using the actual data used to create the forecast.*

<u>Response</u>

The figures illustrated on page 7 of the TGI Annual Review document are the consolidated annual use rates (i.e. TGI as a whole) calculated based on the weighted averages of the regional annual use rates (by rate class), using the number of accounts (by region and rate class) as a basis for the weighting.

The 2005 regional use rate projections are derived from actual customer consumption history by rate class (Rate classes 1, 2, 3, and 23). Annual weather volatility is normalized over the most recent 10-year period and adjustments are calculated for advances in technology, changing preferences with respect to customer choice in housing and building space, and for price elasticity.

The forecast is based on an additive model that directly applies predictor variables to the normalized use rates. Each predictor variable is expressed in gigajoules and added to or subtracted from these rates. The general form of the relationship is as follows:

$\text{Projected}_{\text{use-rate}} = \text{PriorActual}_{\text{use-rate}} + (\text{PriorActual}_{\text{use-rate}} \text{ X Price Effect}) + (\text{PriorActual}_{\text{use-rate}} \text{ X Technology Factor}) + (\text{PriorActual}_{\text{use-rate}} \text{ X Customer Choice Factor})$

Where $\text{PriorActual}_{\text{use-rate}}$ is the previous years normalized actual use rate for that particular rate class and region.

The Price Effect is calculated by applying estimated price elasticity to expected future changes in commodity price. Price elasticity is estimated for each region and rate class by examining the historical actual price impacts on consumption.

Both the Technology factor and Customer Choice factor are estimated to be decreasing consumption by -0.5% per year. These estimates are based on research on end-use trends in the North America market contained in the American Gas Association publication "Patterns in Residential Natural Gas Consumption Since 1980", published February 11, 2000.

To illustrate the calculation of the projected 2005 use rates, the following example for Lower Mainland Rate 1 customers is used:

Expected 2004 normal use rate = 109.8 GJ / Customer

Lower Mainland Rate 1 Price Elasticity = -8.3%

Commodity Price Change 2004-05 = -14%

Price Effect = Price Elasticity X Change in Price = -8.3% X -14% = 1.2%

Projected 2005 Use Rate = 109.8 + (109.8 X 1.2%) + (109.8 X -0.5%) + (109.8 X -0.5%) = 110.0

6.2 *What is the rationale for forecasting a normalized use per account for the Rate 3 customer class that is less than the projected use per account for 2004?*

Response

For the Rate 3 customer class, the 2005 Forecast use rate of 3,426 gigajoules is marginally lower by 1.8% compared to the 2004 Projected use rate of 3,489 gigajoules. The 2004 Projected use rate includes the normalized use rates observed during the first eight months of 2004 which to date is slightly higher than anticipated when compared to recent history. TGI expects 2005 consumption to more follow recent years' experience, excluding the impact of 2004.

6.3 *What is the rationale for forecasting a normalized use per account for the Rate 23 customer class that is less than the projected use per account for 2004, the approved use per account forecast for 2004 and two of the three years between 2001 and 2003?*

Response

The 2005 forecast normalized use per account for Rate 23 reflects a general continuing decline in consumption observed in recent years for higher volume customers (i.e. transport service only), as these customers evaluate and implement energy conservation measures in response to a sustained higher natural gas commodity pricing environment (i.e. since 1999 / 2000).

The 2004 Projected and 2005 Forecast use rates are similar to the most recent full year's experience, the 2003 Normal consumption. The 2004 Approved use per account was based in part on both the 2001 and 2002 normalized consumption use per account, consumption levels which are materially higher than that observed in 2003 and 2004. In retrospect, the 2004 Approved use per account is likely aggressive and did not have the benefit of the full year's 2003 normalized consumption record.

For reference, the 2005 forecast normalized use per account for Rate 23 is only marginally less than the 2004 projection (i.e. ~ 6 gigajoules or less than 1%).

7.0 Reference: Section A, Tab 4, p. 8, Load Forecast – Industrial

The Industrial Firm Sales forecast has trended lower over the past four years. What factors has TGI identified in its customer surveys or through other analysis that would explain that trend?

Response

Please refer to the table in Section A, Tab 4, p. 8.

From 2003 Normal to 2004 Projected, Industrial and Firm Sales customer volumes are expected to decline by approximately 1.8 PJs

Through its recent annual industrial customer survey process, Terasen Gas has identified two significant factors that help explain the declining trend in consumption for these customer rate classes.

1. Energy conservation. As mentioned in response to Question 6.3, Terasen Gas has observed a general continuing decline in consumption in recent years for higher volume customers (i.e. transport service only), as these customers evaluate and implement energy conservation measures in response to a sustained higher natural gas commodity pricing environment (i.e. since 1999 / 2000). Industrial customers continue to look for ways to improve the energy efficiency of their manufacturing equipment and processes. Through the survey process, customers have reported that they have recently installed more energy-efficient equipment or are planning to upgrade their equipment in the new year.

2. Fuel switching. For those industrial customers with fuel switching capability, the use of alternative fuels (e.g. hog fuel) is becoming more economically viable with the sustained higher natural gas pricing environment. The use of alternative fuels is especially prominent in the greenhouse industry which has been particularly sensitive to higher natural gas prices since 2001. On average, of the greenhouse customers' responses to the industrial survey process, the projected decrease in consumption from 2003 levels is about 7% - 8%. The Pulp and Paper and Lumber sectors are two other industries affected by potential fuel-switching.

8.0 Reference: Section A, Tab 4, p. 16, line 8
Other Operating Revenue – Miscellaneous Revenue - Other

Please provide a breakdown of the approved 2004, actual 2004, and forecast 2005 revenues for Miscellaneous Revenue – Other.

Response

	2004 Approved	2004 Projected	2005 Forecast
NRB Recoveries	$ 750,000	$ 931,905	$ 735,799
HomesWest Revenue	160,000	46,324	47,250
TGVI SAP Recoveries	-	462,000	406,000
	$ 910,000	$ 1,440,229	$ 1,189,049

9.0 Reference: Section A, Tab 7, Return on Capital, pp. 1-2

9.1 *The Company has indicated that the synthetic lease will be financed with a conventional mix of $33.7 million long term debt and $16.6 million common equity yet the table on page 2 shows principal debt amount of $50.3 million in long term debt for the Coastal Facilities. Please explain.*

Response

Because the synthetic lease was financed with 100% debt, an interest rate swap was entered into to fix the borrowing costs embedded in the synthetic lease. The interest rate swap currently has a principal amount of approximately $50.3 million. Because the interest rate swap was entered into at rates higher than those prevailing currently, it would cost the Company approximately $3.2 million to unwind the interest rate swap early. Instead, the Company has proposed that the interest rate swap be assumed, and funded with commercial paper issued by the Company. This will spread out the cost of the interest rate swap over the remaining life of the swap (which expires in November 2007).

The effect of this will be that $33.7 million of the interest rate swap will fix the cost of borrowing on the debt issued to finance the unwind of the synthetic lease, and $16.6 million of the interest rate swap will fix the cost of borrowing on debt issued to finance other rate base assets. The cost of this has been reflected in the financial analysis of the synthetic lease unwind that was included with the Annual Review filing.

9.2 *Explain and clarify the following two debt components and the Company's requirement to incur additional long term debt.*

- *2005 long term debt issue of $220 million*
- *LILO Obligations – Prince George $39 million*

Response

As was set out in the Company's 2003 Revenue Requirements Application, Terasen Gas is targeting a capital structure of 33% common equity, 59% long-term debt and 8% short-term debt. Of the 59% long-term debt, 7% is represented by long-term floating rate debt. The issuance of $220 million of long-term fixed rate debt in 2005 is intended to maintain these ratios, given the scheduled maturity of $245 million of long-term fixed rate debt in 2005.

It should be noted that the Return on Capital schedules that are included in the Annual Review filing treat the $50.3 million of swapped debt arising from the synthetic lease unwind (discussed above in the response to question 9.1) as long-term debt because of the interest rate swap arrangement, notwithstanding the fact that these borrowings are funded with short-term commercial paper. If the Unfunded Debt component is adjusted to include this $50.3 million, the Unfunded Debt component of total capitalization increases from 6.7% to 8.8%.

The $39 million of LILO Obligations regarding Prince George arises from the closing of a LILO transaction with the City of Prince George on November 1, 2004 with cash proceeds of $58 million. As with previous LILO transactions, the assets associated with the LILO transaction remain in rate base, and a deemed debt amount is included in the revenue requirement for ratemaking purposes. The cost of the $39 million of deemed LILO debt (67% of LILO assets) with Prince George was determined pursuant to the LILO agreement with Prince George which was approved by the Commission.

10.0 Reference: Section B, Tab 1, pp. 2 and 3, item 2.4, Intermediate Pressure Systems

In the period 2005 – 2009 Intermediate Pressure System Projects consisted of the following:

10.1 *Riverside Road, Abbotsford*

10.2 *72nd Street to 36th Avenue, Delta*

10.3 *Goudy Road and 36th Avenue, Delta*

10.4 *34 B to 57th Avenue, Delta*

Please provide a brief justification for the projects listed above.

<u>Response</u>

The discussion on the justification for the projects is provided below.

Note: With all capital projects, an economic assessment is made prior to construction to ensure proper load forecast support the project.

10.1 Riverside Road, Abbotsford

This project consists of a 1.6 km loop of 323mm O.D. pipeline operating at 1,900 kPa which is planned for construction in 2006 at an estimated cost of $1.1 million (excluding AFUDC).

This system improvement is required to restore capacity in the King Pressure system feeding Abbotsford and Mission to ensure that tail end pressures remain above minimum acceptable levels. The capacity of the King system has been eroded over time by load growth in Abbotsford and to a lesser extent in Mission.

10.2 72nd Street to 36th Avenue, Delta

This project consists of a 2.6 km loop of 323mm O.D. pipeline operating at 1,200 kPa which is planned for construction in 2006 at an estimated cost of $1.8 million (excluding AFUDC).

This system improvement is involved with gas load increase related to greenhouses in the Delta area. With this loop installed greenhouses would not need to be curtailed until colder ambient temperatures are reached.

10.3 Goudy Road and 36th Avenue, Delta

This project consists of a 1.75 km loop of 323mm O.D. pipeline operating at 1,200 kPa which is planned for construction in 2007 at an estimated cost of $1.2 million (excluding AFUDC).

This system improvement is required to increase capacity related to aggressive long term load growth projections that have been provided by the greenhouses in the Delta area. Terasen Gas is planning to meet with the greenhouse owners in the area to validate their long term load growth forecast.

10.4 34 B to 57th Avenue, Delta

This project consists of a 1.5 km loop of 323mm O.D. pipeline operating at 1,200 kPa which is planned for construction in 2008 at an estimated cost of $1.0 million (excluding AFUDC).

As with the *Goudy Road and 36th Avenue, Delta* loop, this system improvement is also required to increase capacity related to aggressive long term load growth projections that have been provided by the greenhouses in the Delta area. Terasen Gas is planning to meet with the greenhouse owners in the area to validate their long term load growth forecast.

11.0 Reference: Section B, Tab 3, p. 12, Demand Side Management ("DSM")

11.1 *TGI states that for the 2004 portfolio...the TRC net benefit has been estimated to be $3.4 million with a combined TRC ratio of 2.36.*

Please provide the calculation of the TRC net benefit and the TRC ratio.

Response

Using standard net present value calculations, individual programs are measured based on the following:

The TRC Net Benefit = TRC Benefits – TRC Costs
The TRC Ratio = TRC Benefits / TRC Costs

TRC Benefit = GJ Savings (net of free riders) * Avoided Gas Costs (measure life)
TRC Costs = Participant Costs (net of free riders) + Program Costs

The "portfolio TRC net benefit" of $3.4 million is the sum of the net benefits of the five individual programs. The combined TRC ratio of 2.36 was calculated as a simple average of the ratios.

12.0 Reference: Section B, Tab 3, Demand Side Management ("DSM") "Billing Analysis: 2002 Residential Heating System Upgrade Program Evaluation" pp. 6 and 10

12.1 *Regarding the modeling of the determinants of installation of a high efficiency furnace, the report states on page 6 that "We also considered income and other variables that proved to degrade the statistical fit of the model." The report then suggests the following probit equation:*

high installi = g(participationi, informationi, incomei, sizei)

Page 10 of the report states that:

> *"...an increase in income leads to a decrease in the probability of purchase of a high efficiency furnace. All of the coefficients except that on income have the expected positive signs and are significant at the 5% level of better."*

12.1.1 *If income proved to degrade the statistical fit of the model, and if income has an insignificant coefficient and does not have an expected positive sign, please explain why income was included in the model.*

<u>Response</u>

As indicated, the model showed a "wrong" sign on income with a coefficient on income that was not statistically significant. However, normal economic practice is to include a theoretically appropriate variable even if the sign is incorrect.

The statistical model used in the 2002 analysis was based primarily on theoretical considerations. In other words, in the absence of any significant literature dealing with the relative quantitative importance of factors influencing choice of furnace efficiency levels, a specification was used that was as consistent as possible with underlying economic choice theory.

13.0 Reference: Section B, Tab 3, Demand Side Management ("DSM") "Billing Analysis: 2002 Residential Heating System Upgrade Program Evaluation" pp. 6 and 9, and "Impact of Terasen Gas/Energy Star Heating System Upgrade (2003) Program," p. 62-63

The 2002 Billing Analysis Report uses a probit equation of the following form to model the determinants of program participation (page 6):

program participationi = f(informationi, incomei, sizei)

On page 62 of the Impact Analysis of the 2003 Program, the following probit equation is used to model the determinants of installation of a high efficiency furnace:

program participationi = f(consumptioni, importance_EEi, importance_costi)

The model used for the 2002 billing analysis showed a model fit of 75.4% of the outcomes correctly predicted (page 9), whereas the model used in the Impact Study showed a model fit of only 51% (page 63).

Please explain why the model was changed for the 2003 Impact Study from that used in the 2002 Billing Analysis, since the model used in the 2002 Billing Analysis appears to have been a better fit and is able to predict a higher percentage of correct outcomes.

Response

For the 2003 analysis, the initial approach was to attempt to replicate the model used for the 2002 analysis since this had worked well with the 2002 sample. However, in order to adequately evaluate the impact of the new features of the program (most notably the variable speed motor offer), the question set was revised to work within the constraint of maximum acceptable survey length. The resulting answer set did not fit well with the 2002 model. Consequently, a number of new models were investigated which provided a better fit to the 2003 data with the "best" new model being the one reported.

Notwithstanding the higher prediction rate of the 2002 model on the 2002 data, the 2003 prediction rate of 51% is considered good and met the objectives of the evaluation.

14.0 Reference: Section B, Tab 4, Utilities Integration Update

14.1 *TGI has identified the total restructuring cost for TGI is $11.3 million and for TGVI is $4.2 million for a gross total of $15.5 million. Of this $15.5 million, please identify common shared restructuring costs incurred for both companies for each line item specified on Table #1, page 5.*

Response

Included in "Related Restructuring Costs Incurred – 2003" is the consulting fee assisting management with integration and staffing process.

14.2 *The anticipated savings for 2005 are expected to be $9.9 million combined for TGI and TGVI. Provide a breakdown of this savings by each individual company.*

Response

The net anticipated 2005 savings by company are as follows:

TGI	$7.9 million
TGVI	2.0 million
Total	$9.9 million

Details behind the savings can be found under Table # 4, Page 6 of the Shared Services Management agreement filed under Section B, Tab 4 of the 2004 Annual Review advance material.

14.3 *Identify the schedules where the 2005 net savings or net restructuring costs are included for TGI.*

Response

The 2003 net restructuring costs of $9,571,000 has been expensed in 2004 in accordance with the terms of the Settlement which states that net restructuring costs incurred by the Company between July 1, 2003 and December 31, 2003 are to be captured in a deferral account, to be recovered as a 2004 expense. Accordingly, it has not been included in the 2005 financial schedules.

For rate setting purposes, net savings are not embedded into the test year financial schedules as the benefits are to be shared through the earnings sharing mechanism. As per the terms of the settlement, to the extent that the 2005 net savings reduce O&M levels below the formula driven O&M, those net savings will increase return on equity. Customer will then benefit from these cost savings through the earnings sharing mechanism.

14.4 *Please provide a copy of TGI's response to the Commission IR pertaining to the Coastal Facilities Project – Variable Interest Entity Application dated August 16, 2004.*

Response

Please see Attachment 1.

15.0 Reference: Section B, Tab 4, Section B, Tab 8 p. 10, Triple Point Project

15.1 *Does TGI expect Intervenor participation in its expected November CPCN application for this project? If not, please provide a detailed financial assessment of the project.*

Response

The Triple Point Application will be for approval of the regulatory construct for providing third party measurement services (pricing, deferral account treatment etc.) and not for approval of a CPCN. However, due to ongoing negotiations for a marketing arrangement for the measurement services, TGI is unable to provide a detailed financial assessment of the proposal at this time and will be seeking conceptual approval from parties at the Annual Review meeting to proceed with an application to the Commission. Once TGI has determined how it will proceed with marketing arrangements for the service (external or internal) and therefore a pricing structure, it will apply to the Commission for approval of the regulatory construct and copy the parties to the negotiated settlement. A financial analysis will be included with the application. Because of the materiality of the initiative, TGI does not expect a lengthy approval process.

15.2 *Does this method of testing high pressure meters require approval from each jurisdiction where the recalibrated meter is used? If so, is there a risk that approval will not be granted?*

Response

This method of testing high pressure meters will require approval from Measurement Canada for all custody transfer use within Canada. In the USA testing of turbine meters is conducted in accordance with the American Gas Association (AGA) Report, Number 7. Individual States or Commonwealths may require local certification in addition to general compliance with AGA standards.

Measurement Canada and the AGA are being kept informed of developments and provisions are being made to facilitate approval of this type of testing.

Measurement Technologies testing standards are fully accredited today with Measurement Canada and are accepted by the US jurisdictions where services are supplied.

The risk that approval will not be granted cannot be eliminated, however, the probability of rejection is anticipated to be minimal.

16.0 Reference: Section B, Tab 4, Material Efficiency Measures: Attachment A – Utilities Strategy Project Update, October 20, 2004 and May 31, 2004 letters

As outlined on the October 20, 2004 cover letter TGI stated that: "…the optimal solution is for TGVI to include in its annual revenue requirement an operating lease expense equivalent to the revenue requirement associated with the assets had the asset transfer taken place…" and "…the recommended proposal is for the assets to reside in the books of TGI, consistent with the common shared technology platform theme, and TGVI will reimburse TGI for the use of the assets as an operating lease at a rate equivalent to ownership of the assets had the asset transfer taken place."

16.1 *The Shared Services Management Report on page 5 explains that the calculation of the 10 percent share of the SAP technology platform to TGVI. "The 10% figure was arrived at after consideration of the relative proportion of TGVI vs. TGI employees (11.5%) and TGVI vs. TGI customers (9.0%)."*

16.1.1 *What shift in employees or customers would be needed before TGI and TGVI will consider changing the 10 percent TGVI portion?*

Response

Terasen Gas will review the ratios of employees and customers on an annual basis. A simple average of the two factors rounded to the nearest percentage will be compared to the current 10 percent allocation factor. A change of at least 2% will trigger a review of the allocation factor methodology.

16.1.2 *What would be the computed percentages if net plant-in-service, total sales volume, and total throughput volume were used instead?*

Response

The computed percents of net plant, total sales volumes and total throughput volumes are 18%, 9% and 13% respectively. TGVI does not believe net plant in service is a good proxy to use as an allocation factor because the TGVI plant system is relatively young as compared to the significantly more mature system of TGI which are both accounted for on a historical dollar basis. The other two remaining factors produce an average ratio of 11%, which is very close to the 10% that TGVI is proposing.

2005	TGI	%	TGVI	%	Total
Net Plant in Service	$ 2,280,774,000	82%	$ 507,755,356	18%	$ 2,788,529,356
Total Sales Volume (GJ)	119,302,000	91%	11,964,802	9%	131,266,802
Throughput Volume (GJ)	224,986,000	87%	33,039,602	13%	258,025,602

16.1.3 *Would the addition of an LNG plant on Vancouver Island affect the proposed allocation methodology?*

Response

No. TGVI believes that Net-Plant-In-Service is not a relevant factor in the determination of the allocation percentage for SAP costs. This is noted in the response to Question 16.1.2.

16.2 *By implementing the proposed October 20, 2004 recommendation, please explain how these assets are shown in the filed TGI financial schedules and its impacts for 2004 and 2005.*

Response

The October 20, 2004 filing recommends that the pro-rata SAP assets remain on the utility financial schedules of TGI as though no transfer has taken place. It also proposes that TGVI reimburse TGI for the use of the assets via an operating lease arrangement at a rate equivalent to ownership of the assets had the asset transfer taken place. TGI will record the operating lease income as other revenues. However, in order to preserve the intent of the negotiated settlement and sharing of the efficiency gains, this will not be included in the annual forecast of other revenues. The 2004 annual review advance material incorrectly included this amount. The Financial Schedules will be updated to reflect this proposed treatment.

16.3 *Is TGI's rate base reduced by TGVI's notional10 percent interest in the net book value of the SAP technology platform?*

Response

To keep things simple, the filing proposes that TGI's rate base will continue to include the 10% interest in the net book value of the SAP technology platform. The cost of service associated with the higher rate base will be mitigated by the operating lease income due from TGVI.

16.3.1 *If so, and the rate base has been reduced where has this adjustment been shown in the plant and other financial schedules? Consequently, is the TGVI equivalent rate base held in another TGI non-rate base account? Please explain how the segregated net book value of the assets is financed?*

Response

TGI is not proposing to move the TGVI equivalent rate base to a non-rate base account. As noted in response to Question 16.3, TGI is proposing that the 10% of SAP remain in TGI's rate base. TGI has taken this position to avoid any transfer pricing issues between utility and non-utility assets. TGI is not opposed to moving the equivalent to a non-rate base account if the transfer can be dealt with expeditiously.

16.3.2 *If not, would this mean that TGI's rate base is unaffected by the operating lease? Please explain.*

Response

TGI's rate base will be unaffected by the proposed operating lease arrangement as discussed in the October 20, 2004 filing. The proposal is for TGVI to reimburse TGI for the use of the SAP assets through an operating lease arrangement all the while retaining the SAP assets in TGI's rate base.

16.3.3 *Under the proposed method, which company claims from Canada Customs and Revenue Agency the CCA or software tax savings?*

Response

Since no actual transfer will be recorded in the Companies financial books, TGI will continue to legally own the assets so the associated CCA and software tax savings will accrue to TGI. However, for rate setting purposes, TGVI will calculate its cost of service as though it owned the assets and as though the income tax savings were available to

TGVI. Once TGVI's related cost of service is known, TGVI will then reimburse TGI and record the reimbursement as an operating lease expense.

16.3.4 *Is TGVI in the same taxable position as TGI? What is the difference, if any?*

Response

TGVI and TGI are both in a taxable position in 2005 and both are subject to the same income tax rate so there are no differences.

16.4 *How are future SAP plant additions and retirements included in the calculation of rate base? How would TGVI maintain its 10 percent portion of the net book value of SAP?*

Response

Future SAP plant additions and retirements will be tracked and TGVI will be allocated its fair portion of the use of the SAP assets based on a BCUC approved methodology. TGVI will calculate the cost of service associated with the notional ownership of the SAP assets and reimburse TGI through lease expense. There will be full transparency as the notional ownership working papers will be made available on request.

16.5 *Where is the TGI lease income that is received from TGVI shown in the filed 2004 and 2005 Terasen Gas financial schedules? Please provide the detailed schedules, if necessary.*

Response

The lease income for 2004 can be found under other operating revenue (Section A, Tab 8, Page 3, Column 3, Line 28). For 2005, it can be located under other operating revenue (Section A, Tab 1, Page 7, Column 3, Line 27). As noted in response Question 16.2, the annual review material incorrectly included this amount as other revenues. The corresponding financial schedules will be amended accordingly.

16.6 *Appendix A of the October 20, 2004 letter shows the Rate Base for 2004 without account details.*

16.6.1 *Please provide all the BCUC account details (including gross balances) and calculations for the rate base including the software, hardware and CIAOC at the start and at the end of the year.*

Response

The cost component of TGVI's 2004 capital structure has been amended to reflect a revised cost component rate of 6.87%. This was the result of a subsequent revision to the filed Appendix A, Schedule 24 of TGVI's 2003 Annual Review. The change is discussed in more detail under response to Question 16.7.1.

APPENDIX A (Amended)

		Based on TGVI's Cost Component	
		2004	**2005**
Rate Base			
FOY - BCUC Account 483-00	Computer Software	$ 2,295	$ 1,383
FOY - BCUC Account 483-00	Computer Hardware	85	-
CIAOC	($2,295 * 34.5%)	(792)	-
Depreciation on Software	($2,295 * 12.5%)	(287)	(287)
Depreciation on Hardware	($85 * 20%)	(17)	(17)
Amort of CIAOC	($792 * 12.5%)	99	99
EOY		$ 1,383	$ 1,178
Mid - Year		$ 1,882	$ 1,281
Cost Component of Capital Structure			
Short-Term		0.58%	0.42%
Long-Term		2.92%	3.36%
Common		3.37%	3.41%
		6.87%	7.19%
Revenue Requirement Impact to TGVI			
Higher Rate Base		$ 163	$ 115
Depreciation (Grossed up for Income Tax)		313	313
Tax savings -hardware		(13)	(13)
		$ 462	$ 414

16.6.2 *Please explain how the CIAOC balance is computed and amortized.*

Response

CIAOC related to computer software tax savings is determined based on the actual tax savings realized from deducting the associated CCA for tax purposes. Instead of reducing income tax expense, the income tax savings are used to reduce the computer software costs. This treatment is consistent with net of tax accounting. The tax savings accrue to the CIAOC account which is then amortized at the same rate as the computer software assets are being depreciated.

16.6.3 *What are the depreciation and amortization rates for each account?*

Response

For BCUC Account 483-00 (Infrastructure computer software), the BCUC approved depreciation rate is 12.5%.

For BCUC Account 483-00 (Computer hardware), the approved depreciation rate is 20%.

The income tax savings associated with the computer software are amortized at the same rate as the assets are being depreciated. The amortization rate for Account 483-00 (infrastructure computer software) is 12.5%.

16.6.4 *Please reconcile the total TGI SAP rate base to the TGVI notional SAP rate base portion.*

Response

Please see Table below.

Terasen Gas Inc.
SAP Capitalized Costs
as at December 31, 2003

APC	Asset	SNo.	CoCd	Cap.date	Asset description	Acquis.val.	Accum.dep.	Book val.	Proposed 10% allocation to TGVI
10083	10016373	2002	2000	12/31/02	SAP 2002 Upgr-HW	333,464.88	(66,692.98)	266,771.90	
10083	10016373	2003	2000	4/30/03	SAP Upgrade	353,274.71	0.00	353,274.71	
10083	10015607	2000	2000	12/31/00	Upgrade to 4.5	29,971.45	(17,982.87)	11,988.58	
10083	10016488	2000	2000	12/31/00	WMS/PM - Computer Hardware	204,623.44	(122,774.07)	81,849.37	
10083	10016488	2001	2000	12/31/01	WMS/PM - Computer Hardware	45,497.28	(18,198.92)	27,298.36	
10083	10016488	2002	2000	1/31/02	WMS/PM - Computer Hardware	21,410.39	(4,282.08)	17,128.31	
10083	10016488	2003	2000	10/31/03	WMS/PM - Computer Hardware	91,149.85	0.00	91,149.85	
GP Computer H/W						1,079,392.00	(229,930.92)	**849,461.08**	**$ 84,946**
10083	10003296	0	2000	12/31/98	IBIS Software development	21,814,576.63	(13,634,110.38)	8,180,466.25	
10083	10003296	1999	2000	12/31/99	IBIS Software development	14,604.57	(7,302.28)	7,302.29	
10083	10003296	2000	2000	4/30/00	IBIS Software development	3,111.33	(1,166.76)	1,944.57	
10083	10003296	2001	2000	5/2/01	IBIS Software development	0.00	(398.68)	(398.68)	
10083	10016372	2001	2000	12/31/01	SAP 2001 Upgrade	8,122.29	(1,023.08)	7,099.21	
10083	10016372	2002	2000	11/30/02	SAP 2002 Upgr-SW	3,211,881.78	(522,805.22)	2,689,076.56	
10083	10016372	2003	2000	4/30/03	SAP Upgrade	630,811.19	0.00	630,811.19	
10083	10015606	2000	2000	12/31/00	Upgrade to 4.5/ Enhancements	2,773,755.53	(1,040,158.32)	1,733,597.21	
10083	10015606	2001	2000	9/30/01	Upgrade to 4.5/ Enhancements	32,917.83	(8,229.46)	24,688.37	
10083	10016489	2001	2000	12/31/01	WMS/PM - Computer Software	4,385,043.15	(1,096,260.78)	3,288,782.37	
10083	10016489	2002	2000	1/31/02	WMS/PM - Computer Software	4,542,623.11	(567,827.89)	3,974,795.22	
10083	10016489	2003	2000	8/31/03	WMS/PM - Computer Software	2,410,172.83	0.00	2,410,172.83	
GP Computer S/W						39,827,620.24	(16,879,282.85)	**22,948,337.39**	**2,294,833.74**
Total SAP asset before Software Tax Credit						40,907,012.24	(17,109,213.77)	**23,797,798.47**	**$ 2,379,780**

16.7 *Appendix A of the October 20, 2004 letter shows the Capital Structure components totaling 6.82 percent.*

16.7.1 *Please confirm that the calculated cost component of the capital structure is based on TGVI's cost of capital.*

Response

The 6.82% cost component of the capital structure is from TGVI's 2003 Annual Review, Appendix A, Schedule 24, Line 4. There was a subsequent revision to the filed Appendix A, with a resulting revised cost component of 6.87%. Accordingly, all of the TGVI's responses under Question #16 have been revised for the 6.87% rate.

16.7.2 *What would be the revenue requirement impact if it were based on TGI's own cost of capital? What is the difference between TGI and TGVI's calculated revenue requirement impact?*

Response

For 2004, TGVI's revenue requirement is $462,000 using its own cost component compared with $472,000 using TGI's cost component. For 2005, the corresponding amounts are $414,000 using TGVI's own cost component compared with $418,000 using TGI's cost components. The revenue requirement impact based on TGI's cost of capital is determined as follows:

TGVI Revenue Requirement Impact ($000)

		Based on TGI's Cost Component 2004	2005
Rate Base			
FOY - BCUC Account 483-00	Computer Software	$ 2,295	$ 1,383
FOY - BCUC Account 483-00	Computer Hardware	85	-
CIAOC	($2,295 * 34.5%)	(792)	-
Depreciation on Software	($2,295 * 12.5%)	(287)	(287)
Depreciation on Hardware	($85 * 20%)	(17)	(17)
Amort of CIAOC	($792 * 12.5%)	99	99
EOY		$ 1,383	$ 1,178
Mid - Year		$ 1,882	$ 1,281
Cost Component of Capital Structure			
Short-Term		0.32%	0.27%
Long-Term		4.22%	4.38%
Common		3.02%	3.02%
		7.56%	7.66%
Revenue Requirement Impact to TGVI			
Higher Rate Base		$ 172	$ 119
Depreciation (Grossed up for Income Tax)		313	313
Tax savings -hardware		(13)	(13)
		$ 472	$ 418

16.7.2.1 *If there is a difference, why should TGVI pay for an amount that is different from what it actually costs TGI?*

Response

As noted, the difference is not material. The proposed treatment is no different than if TGVI had acquired the assets themselves. To comply with the principle of cost causality, it would only be fair for TGVI customers to pay the cost associated with the delivery of the service.

16.7.3 *Please provide the full detailed calculations of these cost component percentages in Appendix A.*

Response

See attached Schedule 24 (Revision #1) of the 2003 Annual Review filing.

16.7.4 *Are these cost components in Appendix A pre-tax or after tax cost percentages?*

Response

The debt related cost components are pre-tax whereas the common equity component is after tax.

16.8 *Appendix A of the October 20, 2004 letter shows the 2004 TGVI Revenue Requirement Impact of $451,000.*

16.8.1 *Please show the calculations of the $162,000 for Higher Rate Base. It appears the FOY rate base is multiplied by the 6.82 percent cost of capital. Is this correct?*

Response

No, it is just a coincidence. The $162,000 is determined by multiplying the pre-tax cost component to mid-year rate base.

Short term cost component	0.57%
Long term cost component	2.92%
Common (3.33% / [1-34.5%])	5.08%
Total pre-tax cost component	8.57%
Mid-year rate base	$1,885,000
Revenue Requirement due to higher rate base	$162,000

16.8.2 *Please reconcile the depreciation of $298,000 with the depreciation (grossed up for income tax) of $303,000.*

Response

Gross depreciation is $298,000. Net depreciation, after amortization of CIAOC of $99,000 is $199,000. Grossed up for tax ($199,000 / [1-34.5%]) = $303,000 pre tax return required to provide for a net depreciation expense of $199,000.

16.8.3 *Please provide the derivation of the $13,000 for tax savings-hardware. Please include the UCC balance, CCA and the CCA rate schedule.*

Response

As part of the proposed SAP transfer, $85,000 of computer hardware will be classified as Class 10 UCC addition, subject to the 30% CCA rate.

		2004	2005
UCC Schedule - Class 10 (Computer Hardware) ($000)			
FOY		$ 85	$ 60
Additions		-	-
CCA	30%	(26)	(26)
EOY		$ 60	$ 34
Tax Savings at 34.5%		$ (9)	$ (9)
Revenue Requirement Impact of Income Tax Savings		$ (13)	$ (13)

16.8.4 *How is the CIAOC included in the revenue requirement impact?*

Response

As noted in response 16.8.2, amortization of CIAOC is netted against depreciation in determining net depreciation and amortization expense. The balance sheet side of the CIAOC reduces rate base.

16.9 *Also, please show all the 2005 detailed TGVI cost calculations similar to the requested information for 2004.*

Response

All of the 2005 detailed TGVI cost calculations have been embedded into the responses to question 16 of this information request, where applicable.

17.0 Reference: Section B, Tab 4, Material Efficiency Measures: Attachment A – Utilities Strategy
Project Update, May 31, 2004 letter and report;
2004 Deferrals - Section A, Tab 3, pp. 11.2-11.3; and
A-8 2004 Projections - Section A, Tab 8, page 4

17.1 *How long do TGI and TGVI envision that the Shared Services Management Agreement will last? Is there an expected termination date for the agreement?*

Response

The agreement is effective January 1, 2004 and continues until December 31, 2004. Thereafter the agreement will automatically be renewed for further one year terms subject to sections 7.2 and 7.3 (outlined in Part 7 of the Shared Services Management Agreement). It is anticipated that TGI will continue to provide management services to TGVI as long as the two companies remain under common ownership in order to maintain the efficiencies created through the restructuring.

17.2 *The agreement indicates that it covers a period of one year starting on January 1, 2004 and can be renewed by one year terms. Do TGI and TGVI consider this a long-term deal? What operational and other changes could happen that would require amendments or changes to the agreement?*

Response

TGI and TGVI consider this a long term deal. The integration of the two entities has produced synergies that will be shared with customers. Customers of both utilities will enjoy the benefits of lower costs as a result of the operational integration undertaken.

The integration of the two entities commenced in late 2003. Many functions have been consolidated and synergies achieved. These synergies were primarily related to General Management and back office support functions. As more functions are integrated, the level of shared services provided will increase. These functions are primarily related to capital investments that are required to allow for a shared information technology platform.

17.3 *Tab A-8, page 1 states: "net restructuring costs incurred by the Company between July 1, 2003 and December 31, 2003 are to be captured in a deferral account, to be recovered as a 2004 expense." Tab B-4, Attachment A, on page 5 of the May 31, 2004 report shows $9.571 million of restructuring costs for TGI.*

17.3.1 *The Settlement in Order G-51-03 defines restructuring costs "as the netting off of savings the Company realizes in 2003 from restructuring activities." Please provide an itemized schedule that shows the details of the $9.571 million in net restructuring costs, including gross retirement and severance costs and the associated savings realized in 2003 to arrive at the 2003 net restructuring costs? When did the realized restructuring costs commence? During which month did most of these restructuring costs occur in?*

<u>Response</u>

The details of the $9.571 million in Net Restructuring costs are:

	$millions
Early Retirement Severance cost	$7.329
Involuntary Severance cost	1.713
Related restructuring cost (Consultants, Bainbridge closure)	0.598
Savings due to termination dates prior to Dec 31, 2003	(0.069)
Net Restructuring cost	$9.571
	=======

The realized restructuring costs commenced in October 2003 for consulting services on the Integration Project (Utility Strategies Project -USP). By the time the affected employees were identified and confirmed it was early December and few employees were released prior to the end of the year.

Most of these restructuring costs were paid in January 2004.

17.3.2 *Have Terasen's external auditors reviewed the calculation of the 2003 net restructuring costs and confirmed it is in accordance with the definition as described in the Settlement in Order G-51-03?*

<u>Response</u>

As part of the year end audit, Terasen's external auditors were provided with BCUC Order G-51-03 as well as information pertaining to the restructuring cost of $9,571 so as to allow for proper audit review of Terasen's deferral accounts.

17.3.3 *The Settlement in Order G-51-03 explains that the restructuring costs will be captured in a deferral account and that "…the deferral account will be non-interest bearing and non-rate base."*

17.3.3.1 *The deferral account does not appear in the 2004 deferral pages in Section A, Tab 3, pages 11.2 and 11.3.*

Which financial schedule shows the amortization of the deferral account?

Response

In accordance with Order G-51-03, the restructuring deferral account is non-interest bearing and non-rate base. Accordingly, the restructuring deferral account has been left off the utility deferral pages to comply with the Order.

The drawdown of the restructuring deferral account appears as a 2004 O&M item. See Section A, Tab 8 Page 1 of the 2004 Annual Review filing for details.

17.3.3.2 *Section A, Tab 8, page 4 does not show the details of the timing differences. Please provide the supporting schedule for the 2004 timing differences. Is the 2004 tax impact of the 2003 net restructuring costs shown in the timing differences? Please explain the tax treatment for the 2003 net restructuring costs in the filed Application. What was the tax effect to TGI in 2003?*

Response

Supporting schedule for the 2004 Timing Differences is attached below.

In the Annual Review Advance Materials (Section A, Tab 8), the 2003 restructuring costs of $9,571,000 have been included in 2004 O&M, consistent with the terms of the 2004/2007 Settlement Agreement. For regulatory tax purposes these are treated as deductible in 2004 so no timing difference adjustment is required on the timing difference schedule. As noted in response 17.3.1, most of the restructuring costs were paid in January 2004 so the tax treatment is consistent with the regulatory treatment.

Some of the restructuring costs were incurred in 2003, so they were available as a tax deduction in 2003 for TGI. However, since customers rates for 2003 and 2004 had already been set, consistent with past practice, tax variances were afforded the same treatment as other forecast variances.

TERASEN GAS INC.
TIMING DIFFERENCES COMPUTATION
($000)

Line No.	Particulars	2004 Approved	2004 Projected	Difference
	(1)	(2)	(3)	(4)
1				
2	TIMING DIFFERENCES ADJUSTMENT			
3				
4	Depreciation	$79,296	$77,542	($1,754)
5	Less: Depreciation Charged to Construction	0	0	0
6				
7	Amortization of debt issue expenses for accounting	1,611	1,485	(126)
8				
9	Debt issue costs for tax purposes	(902)	(905)	(3)
10	Capital cost allowance	(77,331)	(77,584)	(253)
11	Cumulative eligible capital allowance	(1,500)	(1,161)	339
12	Add Back Principle Portion of Coastal Faciliities Lease Paym	1,063	1,063	0
13	Overheads Capitalized for Tax Purposes	(9,753)	(9,753)	0
14	Other Timing Differences	900	1,515	615
15				
16	Total Timing Differences	($6,616)	($7,798)	($1,182)

18.0 Reference: Section B, Tab 7, Customer Security Deposits, Section A, Tab 1, p. 9 Return on Capital

Given the 2005 customer security deposits are forecasted to be $23 million and TGI states: "the balance of the customer security deposits will have effectively substituted what would have been short term debt so it makes sense to include customer deposits in the capital structure similar to short term debt…" (B-7, p. 8).

18.1 *Explain why short term debt has declined by $64.8 million from $225 million in 2004 to $160 million in 2005?*

Response

The apparent reduction in short-term debt as indicated in the Return on Capital schedule is due to the classification of the $50.3 million of debt arising from the unwind of the Coastal Facilities synthetic lease. As discussed in the response to question 9.1, the Company will be assuming an interest rate swap as part of the unwind of the synthetic lease, which fixes the interest rate on these borrowings. The borrowings are funded, however, with commercial paper, which will mature every three months.

These prospective borrowings have been characterized as long-term debt in previous submissions because of the long term fixed rate nature of these borrowings. However, these borrowings utilize the Company's commercial paper borrowing capabilities, and the Company's plans for long-term fixed rate debt issuance in 2005 have been based in part on targeting commercial paper balances. When the interest rate swap expires in November 2007, the Company does not intend to renew the swap or issue new long-term fixed rate debt in substitution.

If the Unfunded Debt component of capitalization is restated to include this $50.3 million, the Unfunded Debt balance for 2005 is $210.8 million, which is substantially unchanged from 2004.

18.2 *Has the net interest savings of $207,000 been included in 2005 revenue requirement? Identify the schedule(s) and line item where this amount has been included.*

Response

Yes, the net interest savings has been included in the 2005 revenue requirement through lower unfunded debt interest. Terasen Gas is proposing to collect through 2005 rates, $6,418,000 of interest (Section A, Tab 1, Page 9, Column 8, Line 12) related to unfunded debt necessary to finance rate base. By lowering actual 2005 unfunded debt interest through accessing customer security deposits, the interest savings will be reflected during 2005. If 2005 actual interest rates fall below the 4% level embedded in the 2005 rates as a result of accessing lower cost customer security deposits, the interest savings will be captured via the deferred interest mechanism and refunded to customers.

19.0 Reference: Section B, Tab 8, pp. 3-4, Core Market Administration Budget

19.1 *Further to the information on pages 3 and 4 of Tab 8, please provide a schedule showing actual Core Market Administration Expenses for TGI and TGVI for 2001, 2002 and 2003, projected expenses for 2004 and budgeted expenses for 2005. On the schedule, please show a reasonably detailed breakout of each year's expenses and average staff complement for each of TGI and TGVI, and the totals for each year.*

Response

Please see table below.

Table for IR 19.1	2001	2002	2003	2001-2003 average	average *110%	2004	2005
Headcount (at year end)							
TGI	15.5*	16.0	16.0	15.8	15.9	17.0	17.0
TGVI	3.0	3.0	3.0	3.0	3.0		
Total	18.5	19.0	19.0	18.8	18.9	17.0	17.0
	* end of year figure, high vacancy level through first 9 months						
Core Market Expense							
TGI							
Labour	$891,371*	$1,210,019	$1,298,245				
Technology & Consulting	$239,121	$129,833	$119,218				
Misc incl Employee Expense	$130,701	$133,974	$189,596				
Subtotal	$1,261,193	$1,473,826	$1,607,059				
TGVI recovery			($169,546)				
Net Gas Supply EMS revenue			($101,304)				
Total	$1,261,193	$1,473,826	$1,336,209				
Budget	*$1,600,000*	*$1,600,000*	*$1,600,000*				
TGVI							
Labour	$255,000	$259,202	$260,000				
Outsourced	$211,800	$253,275	$179,007				
Misc	$52,100	$83,408	$44,546				
Subtotal	$518,900	$595,885	$483,553				
TGW recovery			($42,108)				
Total (excludes Gas Control/SCADA)	$518,900	$595,885	$441,445				
TGW							
Outsourced			$42,108				
Combined (TGI, TGVI, TGW, TGS)							
Labour	$1,146,371	$1,469,221	$1,558,245	$1,391,279	$1,530,407	$1,561,166	$1,715,093
Technology/Consulting/Outsourcing	$450,921	$383,108	$340,333	$391,454	$430,599	$228,229	$328,229
Misc incl Employee Expense	$182,801	$217,382	$234,142	$211,442	$232,586	$347,660	$392,660
Subtotal	$1,780,093	$2,069,711	$2,132,720	$1,994,175	$2,193,592	$2,137,055	$2,435,982
Recoveries	$0	$0	($211,654)	($70,551)	($77,607)	$0	$0
Net Gas Supply EMS Revenues	$0	$0	($101,304)	($33,768)	($37,145)	($131,000)	($70,000)
Total	$1,780,093	$2,069,711	$1,819,762	$1,889,855	$2,078,841	$2,006,055	$2,365,982
Budget	*$2,118,900*	*$2,195,885*	*$2,083,553*				
Labour	$1,146,371	$1,469,221	$1,558,245	$1,391,279	$1,530,407	$1,561,166	$1,715,093
Non-Labour	$633,722	$600,490	$574,475	$602,896	$663,185	$575,889	$720,889

19.2 *Further to the foregoing question, please identify and justify any expense for 2005 that is 110% or more of the average for that component for 2001, 2002 and 2003. Please discuss the impact of the new Energy Management computer system on costs.*

Response

With the combined departments and different operating methodologies (i.e. no longer "outsourcing" energy management for TGVI, it is difficult to draw accurate comparisons beyond labour and non-labour.

During 2001 there was a high level of staff vacancies which netted a savings of $300,000 savings to the labour budget. Similarly there were vacancies in 2002 and 2003. The table below adjusts actual labour spend with these savings to allow comparisons to 2005.

	2001	2002	2003	2001-2003 average	average *110%	2004	2005
Labour	$1,146,371	$1,469,221	$1,558,245	$1,391,279	$1,530,407		
Vacancy impacts	$300,000	$100,000	$106,000	$168,667	$185,533		
Adjusted Labour	$1,446,371	$1,569,221	$1,664,245	$1,559,946	$1,715,940	$1,561,166	$1,715,093

The 2005 labour budget is approximately the same as 110% of the 2001-2003 average. The reason that there is no decrease despite the headcount reduction of 2 is that annual salary increases have exceeded inflation in order to attract and retain highly skilled staff, and lower skilled positions have been replaced by higher skilled and therefore higher paid ones.

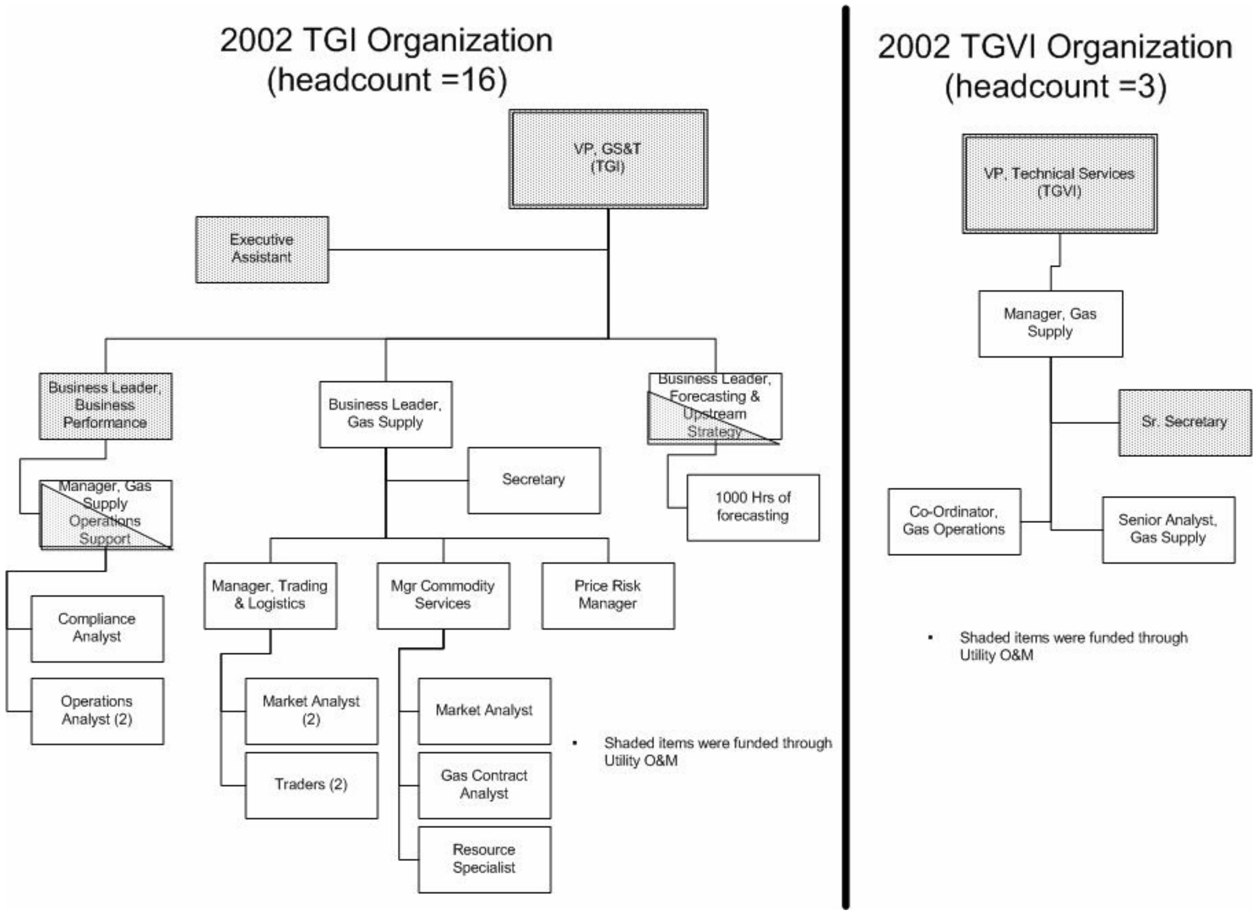
The 2005 increase in non-labour beyond the 110% of the 2001-2003 average ($720,889-$663,185=$57,704) is attributed to

* increased legal costs ($100,000);
* NWGA membership ($45,000); and
* Reorg synergies (elimination of duplicate subscriptions/services and other items for a savings of $90,000).

The new Energy Management computer system would have caused an increase of $91,000 in non-labour costs between 2003 and 2004, but the reorganization synergies of $90,000 offset this increase so that 2004 is only slightly higher than 2003 and is below the 2001-2003 average. The new computer system allows for handling of the essential services model without the planned staff addition originally noted in the unbundling proposal ($74K) and also handles the multiple portfolios for TGI, TGVI, TGW and TGS. Without the new system, additional staff would have been required.

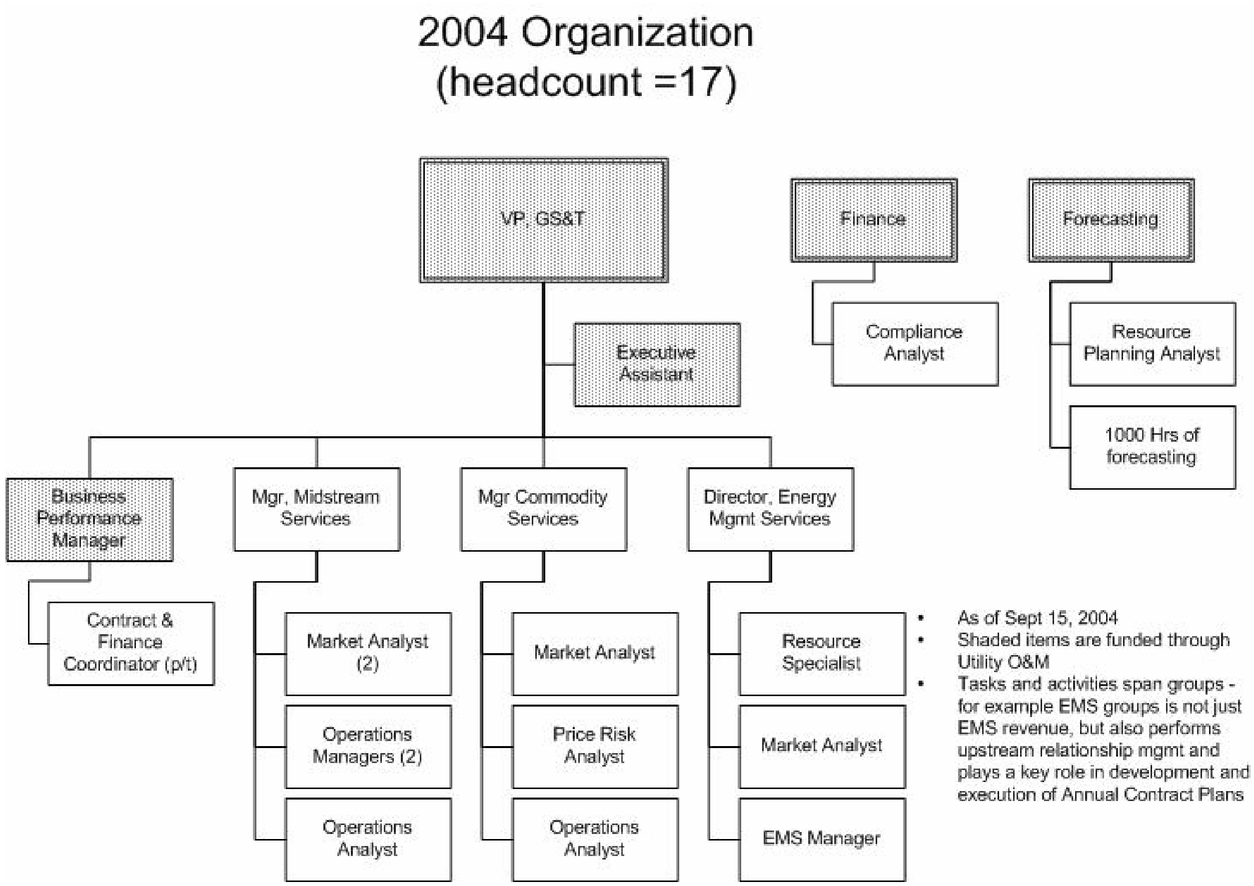
19.3 *Please provide organizational diagrams for the end of 2002 and the end of 2004 for the TGI group(s) that are covered by the Core Market Administration Expense. Please discuss briefly the changes in organizational structure and staff complement that have occurred, and explain why any additional staff was needed.*

Response



Actual headcount on a combined basis for 2002 was 19 and for 2004 headcount is 17 for a net reduction of 2. The 2004 headcount is derived of 16 full-time positions and one full-time equivalent (part-time contract & finance coordinator plus 1000 hours forecasting)

With 2004, the organizational structure has been flattened and organized to support the essential services model. The role of Compliance Analyst now reports up through Finance to provide better separation of due diligence activities.



19.4 *Please identify and explain any costs in 2003 or 2004 that can be attributed to the consolidation of TGI and TGVI. To what extent are these costs expected to reoccur in 2005? Why will they reoccur?*

<u>Response</u>

Costs associated with TGI and TGVI consolidation were attributed to the USP project, and were not charged to Core Market Administration.

19.5 *It could be argued that the current gas marketing environment has fewer rather than more potential counter parties, and that increasing standardization of contracts such as the standard GasEdI documentation should reduce rather than increase the need for legal support. How does TGI respond to these arguments?*

Response

Post Enron requirements to review and negotiate Gas Edi and associated special provisions have increased. Special provisions are modifications to GasEdi language that are typically requested by individual counterparties. Though GasEdi has provided the industry with a starting point with respect to standardized language, it is quite rare to have counterparties agree to accept the Gas Edi language without tailoring the language to better fit their concerns. In fact, a GasEdi committee made up of producers, end users and marketers meet on a regular basis to review and update the GasEdi language as the natural gas market evolves. This year approximately 2/3 of Terasen's GasEdi contracts (6 contracts) have required varying degrees of review and revision to special provisions.

It is anticipated that this legal support would also cover some base level of regulatory interventions for third party pipeline issues (Duke, TCPL, and NWPL). Active intervention in many of these proceedings by TGI has resulted in significant cost savings for TGI core customers as well as other shippers on those pipeline systems. For example TGI core customers benefited by some $5.5 million per year in avoided costs due to TGI intervention into the 2003 Duke Expansion proposal. TGI was able to structure a new set of contracts that significantly reduced the capital cost of adding the planned capacity. The impact of this has become more significant to TGI customers given the level of decontracting that is occurring on the Duke system. TGI also took a lead role in concert with other downstream shippers (U.S.LDCs', industrial customers) in the 2004 Duke rate filing. The requested 12% rate increase was reduced to almost zero as a result of those efforts.

20.0 Reference: Section B, Tab 8, pp. 3, 4 and 6, Core Market Administration Budget

20.1 *The filing shows a Core Market revenue recovery offset of $131,000 for 2004 and $70,000 for 2005. Please explain why this revenue is projected to decline.*

<u>Response</u>

Some revenue opportunities in 2004 are not carrying forward into 2005.

Gas Supply EMS contracts negotiated and signed by clients for 2005 gas year services result in a gross Gas Supply EMS revenue of $274,200. When Gas Supply EMS Cost of Service (COS) of $135, 000 is deducted, this leaves net Gas Supply EMS revenue of $139,200. Under the proposed 50/50 sharing the offset to core would be a credit of $70,000.

New Gas Supply EMS revenue opportunities are being pursued. If new Gas Supply EMS opportunities arise through the year the proportionate Core Market share would be offset against Core market costs thus reducing core costs for customers.

20.2 *Please provide the projected total EMS Revenue in 2004, and the forecast EMS revenue in 2005 from each of TGVI, Whistler, Pacific Northern Gas and Methanex, Terasen Multi-Utility Services and any other parties to whom TGI provides EMS services.*

<u>Response</u>

Starting in 2004 with the consolidation of TGI and TGVI, TGVI no longer is considered Gas Supply EMS revenue. Tables in IR 19.1 show TGVI costs.

Revenue breakdowns for the Gas Supply EMS customers are considered confidential and will be provided on a confidential basis to the Commission if so requested

20.3 *Please identify the date when the Core Supply Administration group commenced providing EMS or other services to each customer.*

<u>Response</u>

Please refer to response to IR 20.2.

20.4 *Have the TGI staff who are covered by the Core Market Administration budget generated any other revenue from external parties in 2004 or are expected to do so in 2005. Please describe this revenue.*

Response

No, all revenue from external parties performed by Gas Supply staff forms Gas Supply EMS services.

20.5 *Further to the information on page 6, please explain how TGI arrived at the 80%/19%/1% allocation factors for Total Gas Supply Core Market Administration Expense to TGI, TGVI and TGW respectively. Why are these factors expected to be appropriate going forward?*

Response

It is proposed to start the 2005 allocation using the same percentage distribution as for 2004, as these figures had already been approved as appropriate costs for the Terasen Gas Utilities, and also already reflect synergies achieved from consolidation. This causes the least overall impact to customers, without causing extra administrative efforts related to complicated allocation methods.

Under the TGI/TGWI Utilities shared services agreement number of customers and/or number of employees are used to allocate costs between the entities. This is not an appropriate methodology for allocating gas supply management costs, as they do not mirror market or plant complexities. Using gas and/or transaction volumes was examined, but this method did not adequately attribute the complexities associated with the TGVI system. Using rate base as a proxy to mirror the value of the transmission/distribution networks and thus size and complexity was also looked at, and it most closely matched current allocation. (83%, 17%, 1%). However as stated above, the selected allocation was based on the ratios created from approved core administration costs for TGI, TGVI and TGW.

20.6 *Please recalculate the table on page 3 assuming all EMS and other third party revenue is used to offset gross Core Market Administration Expense in 2005.*

Response

	Variance from 2004	**Budget**
2004 Gross Core Market Administration Expense		$2,140,982
Labour Inflation	$50,000	
Resource Planning Analyst	$100,000	
Legal	$100,000	
Other Costs	$45,000	
Total 2005 increases		295,000
2005 Gross Core Market Administration Expense		$2,435,982
Gas Supply EMS Cost of Service	$135,000	
Gross Gas Supply EMS revenue	($274,200)	
Net Gas Supply EMS Revenue	($139,200)	($139,200)
2005 Net Core Market Administration Expense		$2,296,782

21.0 Reference: Section B, Tab 8, pp. 6, 7, Core Market Administration Budget

21.1 *On pages 6 and 7, TGI puts forward four reasons why a profit sharing methodology will benefit customers. Please discuss why each reason would not apply as readily in the event all of the incremental EMS revenue was allocated to ratepayers.*

Response

From our filing:

Terasen Gas believes that it is desirable that incentives be put in place to promote utility efficiencies, align customer and shareholder interests and to encourage management to take reasonable risk to control costs in both the long and short run. Customers achieve the benefit of reduced gas costs by:

a) *Receiving a share of EMS net revenue which is applied to offset gross gas supply department costs*

This would apply

b) *Minimizing expense incurred to attract and train new personnel as turnover of skilled employees is reduced. Staff are incented to stay through job enrichment related to additional challenge in their work.*

This would partially applicable. While the work would continue to enhance the work experience for employees and have intrinsic benefit as it benefits customers. The lack of benefit to the Company would not be as highly valued by employees. Nor would the Company be in a position to reward the employees for their efforts in this area as there would not be any additional financial capacity for the company to provide employee incentives.

c) *Increased efficiency of staff, since their skills are used to generate revenue.*

This would apply

d) *Incenting the company (through sharing mechanism) to look for additional revenue generating opportunities.*

This would not apply. The low risk approach for the Company would be to simply perform gas management services for TGI, TGVI, TGW and TGS as prudent costs are flowed through to the customer. By looking for and providing services to others, the Company puts its reputation and image at risk, as well as potential monetary penalties related to poor service which might be disallowed from recovery. The upside is additional revenue. The Company believes that providing EMS Gas Management Services can provide positive net revenue and is worth the associated risk but believes that risk/reward should be shared between customers and shareholders.

Core Market Administration costs are similar in nature to O&M costs. Because of this the Company believes that the 50/50 sharing mechanism related to O&M expense in the current PBR would be an appropriate incentive mechanism. Revenue offsets would be treated as credits to costs which is not dissimilar to how other revenues are treated under O&M expense.

21.2 *Will any of the proposed TGI share of the EMS revenue go directly to the employees who are directly involved? If yes, what portion of the company's share will go to employees, and how will it be allocated within the group.*

Response

No. However, individual employee performance plans may incorporate targets in this areas and therefore such employees may be rewarded indirectly through the Employee Incentive Program.

21.3 *If there is to be an incentive program for 2005, should the threshold for sharing be the forecast net Core Market Administration Expense for 2005?*

Response

The Company believes that the threshold for sharing should be the Core Market Administration Expense prior to any EMS revenues or related expenses. In other words, the Company should be allowed to recover the costs to provide services to Core Customers. Net EMS revenues or expenses should be shared symmetrically. In its proposal Terasen Gas has effectively locked in the first $70,000 of sharing of net EMS revenue by allocating the net Core Market Administration Expense.

21.4 *Commission Order No. G-98-04 approved an extension of the Gas Supply Mitigation Incentive Program ("GSMIP") for the November 2004 to October 2005 gas year. What incentive amount does TGI project it will earn under GSMIP in 2004/05? Please explain why the proposed EMS revenue sharing program is needed and appropriate, in addition to GSMIP?*

Response

For 2004/05, the projected TGI GSMIP incentive amount is approximately $1.1 million.

The GSMIP is a mechanism directed at incenting TGI to seek out opportunities to reduce the cost of fixed assets held by TGI to meet design day requirements of customers. The focus is on mitigating third party costs, particularly for third party gas transport and storage assets. The midstream portfolio is built using normalized weather curve and assumes a constant winter/summer baseload from marketers (including the Utility as marketer for bundled customers). Actual weather presents opportunity to shed extra resources and to take delivery at other points based on an optimized cost analysis. The GSMIP plan incentives reward the company, and staff for these efforts.

The EMS revenue sharing incentive more closely mirrors the PBR incentives.

22.0 Reference: Section B, Tab 8, Exogenous Factors – Ontario Securities Commission Certification Compliance Costs

22.1 *TGI states: "Certain of the shared costs of the project are incurred at Terasen Inc. and then cross charged to Terasen Gas…" (B-8 p. 19).*

Identify the total 2004 and 2005 costs incurred by Terasen Inc. and the amount cross charged to TGI with reference to the table of costs on page 19.

Response

The determination of 2004 and 2005 cross charges from TI to TGI for certification compliance costs are as follows:

Terasen Gas Inc. - OSC Compliance Costs

	2004 Budget				
	Terasen Inc.	Allocation Rate *	Allocation to Terasen Gas Inc.	Incremental Costs Terasen Gas Inc.	Total Terasen Gas Inc.
External Fees - Deloitte					
Initial Bare Certification	$ 80,000	50%	$ 40,000		$ 40,000
Scoping, Planning, Disclosure Processes	265,700	50%	132,850		132,850
Financial Reporting Processes	285,700	50%	142,850		142,850
Admin Fee (5%)	32,445	50%	16,223		16,223
External Fees - KPMG					
Project Steering Committee	25,000	50%	12,500		12,500
Incremental Internal Costs					
Resourcing	54,646	50%	27,323	21,750	49,073
Technology	18,757	50%	9,379		9,379
Other	9,100	50%	4,550		4,550
Contingency	50,808	50%	25,404		25,404
Total	$ 822,156		$ 411,078	$ 21,750	$ 432,828

* Allocation is consistent with standardized allocation of corporate costs by Terasen Inc. based on the Massachussets Method as approved by the BCUC.

Terasen Gas Inc. - OSC Compliance Costs

	2005 Budget				
	Terasen Inc.	Allocation Rate *	Allocation to Terasen Gas Inc.	Incremental Costs Terasen Gas Inc.	Total Terasen Gas Inc.
External Fees - Deloitte					
Initial Bare Certification	$ -	50%	$ -		$ -
Scoping, Planning, Disclosure Processes	-	50%	-		-
Financial Reporting Processes	368,000	50%	184,000		184,000
Admin Fee (5%)	-	50%	-		-
External Fees - KPMG					
Project Steering Committee	25,000	50%	12,500		12,500
Incremental Internal Costs					
Resourcing	250,000	50%	125,000	87,000	212,000
Technology	-	50%	-		-
Other	-	50%	-		-
Contingency	25,000	50%	12,500		12,500
Total	$ 668,000		$ 334,000	$ 87,000	$ 421,000

* Allocation is consistent with standardized allocation of corporate costs by Terasen Inc. based on the Massachussets Method as approved by the BCUC.

22.2 *"The purpose of MI52-109 is to improve the quality and reliability of reporting issuers' annual and interim disclosures. The CSA believes that this, in turn, will help to maintain and enhance investor confidence in the integrity of Canadian capital markets." (B-8, p. 18)*

Since this new certification requirement is to protect and enhance shareholder confidence in the capital market, how will the ratepayers benefit from absorbing this cost?

Response

This new certification requirement is intended to benefit all investors, both equity and debt. Compliance with MI52-109 is mandatory, not voluntary, for all OSC registrants. Terasen Gas Inc. is currently an OSC registrant by virtue of its public debt not its equity and, therefore, is obliged to comply with MI52-109. Compliance with MI52-109 is also imperative in order for the Company to preserve its continued access to the public debt markets. If the Company was to lose its access to the public debt capital markets, its cost of borrowing would increase significantly, which would harm ratepayers.

ATTACHMENT 1

Terasen Gas

Scott A. Thomson
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September 23, 2004

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

Attention: R.J. Pellatt, Commission Secretary

Dear Sir:

RE: Terasen Gas Inc. ("Terasen Gas" or the "Company")
Coastal Facilities Project – Variable Interest Entity

Terasen Gas submits the enclosed responses to Commission Information Request No. 1 relating to the above-mentioned Application, filed on August 16, 2004.

We trust the Commission will find the responses to be in order; however, should further information be required, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed by Tom Loski for:

Scott Thomson

Enclosure

TERASEN GAS INC.

COASTAL FACILITIES PROJECT – VARIABLE INTEREST ENTITY

RESPONSE TO COMMISSION INFORMATION REQUEST NO. 1

1.0 Terasen Gas Inc. has applied to unwind the synthetic lease on the Coastal Facilities Asset by adopting the new provisions of the Accounting Guidelines AcG-15. However, AcG-15 is not a CICA Handbook requirement but only a guideline. Please explain why TGI believes it is imperative to adopt this new accounting guideline change.

Response

The Canadian Institute of Chartered Accountant's Handbook Section 1100 "Generally Accepted Accounting Principles" establishes standards for financial reporting and describes what constitutes Canadian Generally Accepted Accounting Principles (GAAP) and the sources to follow or consult to comply with GAAP.

Paragraph 1100.03 states that: "*An entity should apply every primary source of GAAP that deals with the accounting and reporting in financial statements of transactions or events encountered by the entity. [OCT. 2003]*"

Paragraph 1100.02 further defines primary sources of GAAP as follows:

c) ***Primary sources of generally accepted accounting principles (primary sources of GAAP)*** *are, in descending order of authority:*
- *(i) Accounting Handbook Sections 1300-4460, including Appendices and Board Notices;*
- *(ii) Accounting Guidelines, including Appendices and Board Notices;*
- *(iii) Abstracts of Issues Discussed by the Emerging Issues Committee (EIC Abstracts), including Appendices;*
- *(iv) Background Information and Basis for Conclusions documents accompanying pronouncements described in (i)-(ii), including Appendices;*
- *(v) Illustrative material[1] of those pronouncements described in (i)-(iv); and*
- *(vi) Implementation Guides authorized by the Board.*

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[1] Illustrative material includes the decision tree and examples embedded in EMPLOYEE FUTURE BENEFITS, Section 3461, and the examples embedded in INCOME TAXES, Section 3465, and EARNINGS PER SHARE, Section 3500.

All Accounting Guidelines are now considered a primary source of GAAP and must be followed when applicable, despite the issue that there is not a Handbook Section issued on Variable Interest Entities.

In order for Terasen Gas Inc. to comply with GAAP, Accounting Guideline-15 must be applied for its fiscal year commencing January 1, 2005.

2.0 *If Terasen Gas Inc. did not adopt this accounting guideline effective January 1, 2005, what would be the financial impact to the shareholders?*

Response

When the Coastal Facilities synthetic lease was established, the Company agreed that the Coastal Facilities project could be financed outside of rate base with 100% debt within the synthetic lease, because the debt would not appear on the Company's balance sheet and therefore the debt ratio reported in the Company's financial statements would be preserved. Because the synthetic lease is effectively financed with 100% debt, on-balance sheet accounting for this obligation will result in the Company's debt ratio exceeding the levels presently authorized by the BCUC and expected by credit rating agencies. In order to restore the Company's debt ratio to levels expected by credit rating agencies, the Company will need to issue or retain additional common equity, which it would not be permitted to earn an appropriate return on unless the Coastal Facilities assets are included in rate base, with an allowed return based on 33% equity and 67% debt. If Terasen Gas Inc. did not adopt this accounting guideline effective January 1, 2005 for rate setting purposes, shareholders will be negatively impacted by the loss of $1.1 million in revenues. This would not be consistent with BCUC Order No. C-14-98 which confirms that "the Company shareholders will be protected from the impact of changes to the current accounting and tax rules" and "if it is not feasible to renew the lease arrangement, the outstanding costs of the Project may be financed as a traditional rate base item".

Failure to comply with the pronouncements would result in a material misstatement of the financial position of the Company that could result in a qualification of the Auditor's opinion on the financial statements of the company. Should this occur, it would result in a default under the Company's credit facilities and also result in both Terasen Gas Inc. and Terasen Inc. being designated as defaulting issuers by Canadian securities exchanges resulting in a suspension of trading in our parent company's shares on those exchanges and denying both Companies' access to debt and equity financing.

3.0 *This accounting change would have a significant impact on the cost to be recovered from the ratepayers. What would be the impact to the shareholders if the Commission decides to approve a variance from GAAP to continue with the existing treatment or status quo?*

Response

As stated in the answer to question #2 above, the financial impact to shareholders of Terasen Gas inc. will be a loss of $1.1 million in revenues should the present treatment continues. There is no exemption for rate-regulated enterprises to deviate from compliance with GAAP for externally-reported financial statements that require an audit opinion. Given that there have been a continuing series of ongoing discussions within the Accounting Standards Board to remove other exemptions from complying with GAAP for rate-regulated enterprises, it is extremely unlikely that Terasen Gas would be allowed to not adopt the accounting guideline and receive an unqualified audit opinion on its financial statements.

3.0 Order No. G-51-03 included a "no surprises" term to ensure that any significant changes or restructuring at the utility will have been discussed with interested parties in order to reduce the risk of undesirable outcomes. Please comment on any concerns the Company may have if this Application was to be deferred to Terasen's Annual Review in November.

Response

Terasen Gas believes that the process taken to-date to implement the variable interest entity accounting change complies with the "no surprises" clause since interested parties have been well informed of the Company's intent.

In the 2003 Annual Review Advanced Material provided to all interested parties (Section B, Tab 8, Page 1), Terasen Gas stated that it expected to end the Coastal Facilities synthetic lease arrangement and planned to file a separate application for Commission approval to include the Coastal Facilities assets in rate base effective January 1, 2005. At the 2003 Annual Review, Terasen Gas repeated the message via a slide presentation that the accounting change for variable interest entities has been delayed until 2005 and that Terasen Gas will be making an application to the Commission in 2004 to deal with this accounting change. The Coastal Facilities Project – Variable Interest Entity application that is before the Commission is in keeping with the commitment made by Terasen Gas to file an application with the Commission in 2004 to address this matter.

Terasen Gas is not opposed to deferring this matter to the upcoming Annual Review in November. However, given the full agenda of the upcoming one day Annual Review plus the fact that this application is simply to carry out the compliance aspect of BCUC Order No. C-14-98 which confirms that "the Company shareholders will be protected from the impact of changes to the current accounting and tax rules" and "if it is not feasible to renew the lease arrangement, the outstanding costs of the Project may be financed as a traditional rate base item", Terasen Gas suggests that this administrative matter be dealt with prior to the Annual Review.