1.0 Gas Plant in Service

Reference: Application, Section C, Tab 3

1.1 *Since delivery rates last changed effective January 1, 1995, please provide a schedule showing Gas Plant in Service closing balances for 1994 through 2002, by account as shown for 2002 in Tab 3, page 3.2, column 2*.

Response

Please see table below.

TERASEN GAS INC. - FORT NELSON SERVICE AREA
GAS PLANT IN SERVICE BALANCES
($000)

B.C.U.C. Account	1994	1995	1996	1997	1998	1999	2000	2001	2002
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TOTAL MANUF. GAS / LOCAL STORAGE (Accounts 401 to 449)	0	0	0	0	0	0	0	0	0
460/461 Land in Fee Simple/Land Rights	6	6	6	6	8	8	8	8	8
462 Compressor Structures	0	0	0	0	0	0	0	0	0
463 Measuring Structures	0	0	0	0	0	0	0	0	0
464 Other Structures and Improvements	7	7	7	7	7	7	7	7	7
465 Mains	1,052	1,052	1,061	1,062	1,076	1,076	1,108	1,108	1,163
466 Compressor Equipment	0	0	0	0	0	0	0	0	0
467 Measuring and Regulating Equipment	73	64	64	68	68	75	77	77	73
468 Communication Structures and Equipment	1	0	0	0	0	0	0	0	0
469 Other Transmission Equipment	0	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION PLANT	1,139	1,129	1,138	1,143	1,159	1,166	1,200	1,200	1,251
470 Land	0	0	0	0	0	0	0	0	0
471 Land Rights	20	20	20	20	20	20	20	20	20
472 Structures and Improvements	59	69	56	63	63	65	86	89	89
473 Services	1,252	1,392	1,447	1,470	1,507	1,514	1,546	1,574	1,621
474 House Regulators and Meter Installations	111	135	160	196	358	402	484	522	533
475 Mains	777	836	894	975	1,008	1,008	1,118	1,144	1,162
476 Compressor Equipment	313	299	304	304	0	0	0	0	0
477 Measuring and Regulating Equipment	279	263	231	218	249	520	711	706	706
478 Meters	102	100	92	85	85	68	62	58	52
479 Other Distribution Equipment	0	0	0	0	0	0	0	0	0
TOTAL DISTRIBUTION PLANT	2,913	3,114	3,204	3,331	3,290	3,597	4,027	4,113	4,183
480 Land	1	1	1	1	1	1	1	1	1
481 Land Rights	0	0	0	0	0	0	0	0	0
482 Structures and Improvements									
- All Other	182	218	219	220	232	232	232	232	234
483 Office Furniture and Equipment									
- Furniture & Equipment	16	15	28	32	40	41	41	41	41
- Computers - Hardw are	56	78	113	161	177	199	195	194	184
- Computers - Softw are	64	144	170	200	232	382	369	361	187
484 Transportation Equipment	69	69	99	56	10	10	10	10	10
485 Heavy Work Equipment	73	73	73	73	0	3	3	3	3
486 Tools and Work Equipment	83	87	77	84	112	118	118	118	105
487 Equipment on Customer's Premises	1	1	1	0	0	0	0	0	0
488 Communication Equipment	33	30	35	38	40	40	1	1	22
489 Other General Equipment	0	0	0	0	0	0	0	0	0
TOTAL GENERAL EQUIPMENT	578	716	816	865	844	1,026	970	961	787
496 Unclassified Plant	0	0	0	0	0	0	0	0	0
497 Allow ance for Funds Used During Construction	7	0	0	0	0	0	0	0	0
498 Overhead Charged To Construction	1	0	119	222	289	359	418	480	547
499 Plant Suspense	0	0	0	0	0	0	0	0	0
TOTAL UNCLASSIFIED PLANT	8	0	119	222	289	359	418	480	547
TOTAL CAPITAL	4,638	4,959	5,277	5,561	5,582	6,148	6,615	6,754	6,768

1.2 *Please identify and justify any capital additions over the 1995 to 2002 period that are substantial and significantly larger than normal for the account*.

Response

Capital additions for accounts 473, 474, 475 and 477 are addressed in the response to Question 1.3 below.

Larger than normal additions were made in accounts 465 in 2002 and 483 in 1998. In account 465 Transmission Mains $55,000 was added in 2002, for the replacement of two leaky valves on the Fort Nelson lateral pipeline. In account 483 Computer Software $74,000 was added in 1999, Fort Nelson's portion of the SAP (Terasen Gas' integrated financial accounting system) implementation costs.

1.3 *How many residential and commercial customers were added over the 1995 through 2002 period (total and net)? Please explain and justify the increases in Gas Plant in Service over the 1995 through 2002 period for each of the following accounts:*

Account 473 – Services
Account 474 – House Regulators and Meter Installations
Account 475 – Distribution Mains
Account 477 – Measuring and Regulating Equipment

Response

TERASEN GAS INC. - FORT NELSON SERVICE AREA
TOTAL AND NET CUSTOMER ADDITIONS

Customer Type	1995	1996	1997	1998	1999	2000	2001	2002
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Residential (total)	n/a	n/a	35	44	11	22	25	32
Residential (net)	84	69	55	33	(6)	1	13	28
Commercial (total	n/a	n/a	2	6	0	3	3	5
Commercial (net)	25	30	4	14	(5)	(12)	(1)	11

TERASEN GAS INC. - FORT NELSON SERVICE AREA
NET GAS PLANT ADDITIONS BY YEAR
($000)

B.C.U.C. Account	1995	1996	1997	1998	1999	2000	2001	2002
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
473 Services	140	55	23	37	7	32	28	47
474 House Regulators and Meter Installations	24	25	36	162	44	82	38	11
475 Mains	59	58	81	33	0	110	26	18
477 Measuring and Regulating Equipment	(16)	(14)	(13)	31	271	191	(5)	0
TOTAL	207	124	127	263	322	415	87	76

Additions to plant accounts 473 Services and 474 House Regulators and Meter Installations are related to the increases in residential and commercial customers. This covers the cost of the materials and labour used to connect a service to the distribution system.

Plant additions to accounts 475 Mains and 477 Measuring and Regulating Equipment are done based on the demand of the distribution system. These additions do not have a direct relationship to the annual customer additions. Mains capital is spent when replacements, improvements or extensions are required to service existing and new customers. Additions to plant account 477 Measuring and Regulating Station Equipment were for upgrades to stations and telemetry equipment.

1.4 *Tab 3, page 2 shows Plant Disposals of $230,000 in 2002. Please identify and explain each material item included in this amount*.

Response

One item accounted for the majority of the $230,000 plant disposal in 2002. $180,000 of the disposals was for the retirement of computer software. This amount represented the Fort Nelson portion of the customer information system that was sold to CustomerWorks.

1.5 *Tab 6, page 4 projects 26 residential and 5 commercial customer additions in 2003. Please identify the portion of the $115,000 of Additions for Services in*

2003 shown on Tab 3, page 3.2 that relates to residential additions. Did the Main Extension test require customer contributions? If so, please identify the amount and where they are reported in the Application.

Response

The portion of total service additions of $115,000 ($70,000 direct costs and $45,000 capitalized overhead) related to residential additions is $105,000 ($64,000 direct costs and $41,000 capitalized overhead). Residential service additions of $105,000 were based on an Operations forecast of 80 new residential services. The 26 residential additions noted on tab 6, page 4 is a Marketing forecast and also reflects net additions (new services less disconnects). Timing issues account for the difference between the Operation and Marketing forecasts. There can be up to a 3 month lag between when a service is installed (Operations) and when the customer is entered into the billing system (Marketing).

The main extension test was applied to the new main extensions in Fort Nelson and all of the mains were economic; therefore no customer contributions were required,

1.6 *Please explain why additions of $96,000 in 2004 are forecast for Account 475.*

Response

Forecast additions to account 475 of $96,000 ($64,000 direct costs and $32,000 capitalized overhead) are for Distribution System improvements. Terasen Gas' system model suggests that 50 customers in the western part of town are at risk of outages in extreme cold.

1.7 *Tab 3, page 3.1, Account 498 shows $547,000 of Overhead Charged to Construction. Pages 3.2 and 3.3 show a similar total amount as opening adjustments to Transmission and Distribution Gas Plant in Service for 2003. Please explain how and over what period the amount in Account 498 was accumulated, justify the amount and explain why it was distributed to Transmission and Distribution Plant as shown*.

Response

The balance of $547,000 of Overhead Charged to Construction has been accumulating since 1996 when the Terasen Gas adopted a policy of not distributing the annual overheads to the capital expenditures of that year. Prior to 1996 overhead was charged directly to construction assets. The total amount of $547,000 is the sum from 1996 of annual Fort Nelson allocations from the Terasen Gas corporate total overhead capitalized. The annual allocations to

Fort Nelson were based on Fort Nelson's percentage of total Company sales and transportation volumes.

The balance of Overhead Charged to Construction was distributed to Transmission and Distribution plant because these assets are typically managed and constructed by internal resources. The overhead is applicable to this type of work.

1.8 *If the amount in Account 498 relates to a specific project or projects, please identify each project and justify the expenditure on each including the number of new customers and the incremental customer load that resulted*.

Response

Please see response to Question 1.7 above.

1.9 *The third revision of Fort Nelson Tariff Sheet No. 6, effective April 25, 2000 refers to the General Terms and Conditions of the BC Gas (now Terasen) Tariff for the General Terms and Conditions for Fort Nelson. Please confirm that Section 12 "Main Extension" of the Terasen tariff applies for the Fort Nelson service area*.

Response

Terasen Gas confirms that Section 12 "Main Extension" of the Terasen Gas tariff also applies to the Fort Nelson service area.

1.10 *When did service to customers in Prophet River commence? If service started in the past five years, please identify the cost of plant to serve the area, the number of customers currently being served and the total gas delivered and margin revenue for each year since service commenced*.

Response

Service to the customers in Prophet River commenced in the later part of the 1980's.

1.11 *Note 1 on Tab 3, page 2.1 identifies a $100,000 capital addition in 2004 as replacement of an odourizer. Please outline the project cost and schedule, and confirm that the replacement is consistent with Terasen's minimum requirements for such equipment*.

Response

The replacement of the odourizer is part of five-year program to bring operating facilities into compliance with environmental regulations. The $100,000 is a preliminary estimation of the cost to replace a buried odourant tank with a double-walled vessel. The $100,000 estimate will be refined once the quotes on the vessel have been obtained and the design completed. Terasen Gas confirms that the replacement is consistent with the Company's minimum requirements.

1.12 *Further to Tab 3, page 3, please explain what the $60,000 Transmission Main addition in 2004 is for, and why it is needed*.

Response

The expenditure of $60,000 ($40,000 direct costs and $20,000 capitalized overhead) is required for the upgrade and replacement of two road crossings on the Fort Nelson Indian Band lands. Road crossings are required to protect the transmission pipe from possible damage caused by the weight of vehicles driving over it.

2.0 Unamortized Deferred Charges and Amortization

Reference: Application, Section C, Tab 3, pp. 6.1- 6.2

2.1 *Please explain the amount of $235,000 appearing on page 6.1, column 9. Was this amount factored into the derivation of the 2004 revenue requirement? If not, why not*?

Response

The $235,000 is the Company's projection of the December 31, 2003 GCRA balance on a net-of-tax basis. This balance is forecast to be reduced to nil by December 31, 2004 through higher forecast incurred gas costs over recovered gas costs. The lower rate base impact of the $235,000 has been factored into the derivation of the 2004 revenue requirement. The $235,000 will be returned to customers in the next cost of gas flow-through application to be filed with the Commission. Consistent with Commission Letter No. L-5-01, this amount is to be refunded over 12 months.

3.0 Accumulated Depreciation and Expense

Reference: Application, Section C, Tab 4

3.1 *Please explain why the total plant balance as at December 31, 2002 on page 4.2, line 27 (i.e. $7,937,000) differs from the total plant balance as at December 31, 2002 in Section C, Tab 3, page 3.3, line 28 (i.e. $6,768,000).*

Response

The account 467-00 Measuring & Regulating Equipment (Section C, Tab 4, Page 4.1 Line 10) is incorrectly shown as $1,270,000 **.** The correct balance should be $70,000. Consequently, the 2003 depreciation of $38,000 is overstated from the correct amount of $2,000, resulting in an overstatement of the 2004 accumulated depreciation. The correction of this item adjusts the accumulated depreciation going into 2004 which increases 2004 rate base by $36,000. The impact on the 2004 Revenue Requirement is an increase in the revenue deficiency of $4,000.

The table below reconciles the plant balances used in the calculation of 2003 accumulated depreciation to the amount in gas-plant-in-service.

	($000)
Total on Section C, Tab 4, Page 4.2, Col 2, Line 27	$7,937
Correction to Account 467-00 Measuring and Regulating ($1,270 to $70)	(1,200)
Land and Land Rights Accounts (non-depreciable plant accounts: #460, 461, 471 & 480)	31
Total (Section C, Tab 3, Page 3.3, Col 3, Line 28)	$6,768

Reference: Application, Section C, Tab 4, p. 3.2

3.2 *It appears that the net book value for Computers - Hardware as at December 31, 2003 is projected to be negative [i.e. $174,000 - $232,000 = $(58,000)]. Please confirm. If the answer is yes, please provide a detailed justification for calculating depreciation expense of $35,000 for Computers – Hardware for the 2004 Test Year*.

Response

The schedule omitted a retirement in 2003. The projected computer hardware balance for December 31, 2003 after incorporating the retirement would be a gross plant cost of $17,000 with accumulated depreciation of $10,000. The retirement was for pre-1999 corporate hardware purchases.

Making the correction reduces the 2004 depreciation expense on Computer Hardware by $32,000 and increases the 2004 rate base by $80,000. The 2004 Computer Hardware depreciation expense should be $3,000 instead of

$35,000. The net effect of the correction on the 2004 revenue requirement is a revenue deficiency reduction of $41,000.

4.0 Gas Sales & Transportation Volumes for 2004 - Customer Additions Forecast

Reference: Application, Section C, Tab 6, pp. 3-4

4.1 *Please provide a table showing the number of customers by rate class (Rate 1, 2.1, 2.2 and 2.5) at year-end for 1995 through 2002 (actual), 2003 (projected) and 2004 (forecast)*.

Response

The requested data is provided in Table 4.1 below.

Table 4.1

Total Fort Nelson Customers at Year End - Rates 1, 2.1, 2.2 and 25

Rate	**Actual 1995**	**Actual 1996**	**Actual 1997**	**Actual 1998**	**Actual 1999**	**Actual 2000**	**Actual 2001**	**Actual 2002**	**Projected 2003**	**Forecast 2004**
Rate 1	1,547	1,616	1,671	1,704	1,698	1,699	1,712	1,740	1,766	1,784
Rate 2.1	318	348	352	366	361	349	336	348	336	337
Rate 2.2	2	2	2	2	2	2	14	13	30	30
Rate 25	0	2	2	2	2	2	2	2	2	2
Total All Rates	1,867	1,968	2,027	2,074	2,063	2,052	2,064	2,103	2,134	2,153

Household Formations [1]	5.3%	4.5%	4.2%	-0.9%	-1.0%	-1.7%	1.1%	0.0%	0.4%	0.7%
Population Growth [2]	5.2%	4.1%	2.9%	-2.0%	-1.8%	-3.4%	0.6%	1.5%	0.0%	1.0%

Note: Household Formations and Population source data are provided by BC Stats.

4.2 *Tab 6, page 3 represents that the Summary Table on page 4 shows the year over year changes in household formations. The information is missing*.

4.2.1 *Please show the historical and expected annual household and population growth rates between 1995 through 2004 in the Summary Table referred to above*.

Response

This additional information is provided as requested in Table 4.1 above.

4.2.2 *Please identify those years where customer additions/disconnections cannot be correlated to household and population growth rates*.

Response

In constructing models of year over year account growth, Terasen Gas has confirmed that percentage change in household formations and percentage change[3] in total population are both well correlated with Residential and Commercial account additions. While some years may show a weaker correlation between the variables than others, overall the relationship is in fact strong, and directionally consistent.

The year 1998 may be an exception. Removing this year improves the correlation between account additions and each of the other two demographic variables – household formations and population change.

The data series is presented in Table 4.2.2 A below:

Table 4.2.2 A

Year	Household Formations	Population Change	Customer Additions

[1] Household Formation Data applies to the Fort Nelson Health Region.
[2] Population Data applies to the Town of Fort Nelson.
[3] Data applies to the Town of Fort Nelson and/or its environs. Please refer to Table 4.1 for more detail on data sources.

1995	5.26%	5.20%	6.20%
1996	4.53%	4.08%	5.41%
1997	4.19%	2.90%	3.00%
1998	-0.90%	-2.00%	2.32%
1999	-1.05%	-1.80%	-0.53%
2000	-1.69%	-3.40%	-0.53%
2001	1.08%	0.60%	0.58%
2002	-0.03%	1.50%	1.89%

The correlations with and without the year 1998 are presented below in Table 4.2.2 B to confirm the strong association between the variables. This statistic measures how closely two variables are linearly related, with values of 1 or -1 indicating a perfect linear fit. For each covariate, there is a noticeable improvement in correlation when 1998 values are removed, although the measure is strong in either case.

Table 4.2.2 B
Correlation Coefficients
(Pearson)

	Household Formations	*Population*
Total Accounts	0.82	0.82
Total Accounts less 1998	0.88	0.90

5.0 Gas Sales & Transportation Volumes for 2004 - Use Per Customer Account

Reference: Application, Section C, Tab 6, pp. 4-5

5.1 *Please provide a table showing the individual use per account by rate class (Rate 1, 2.1, 2.2 and 2.5) for the period 1995 through 2002 (both actual and normalized), 2003 (projected) and 2004 (forecast)*.

Response

The requested information is presented in the following table.

Fort Nelson Service Area
Annual Use
Rate 1, 2.1, 2.2, 3.1, 3.2 and 25
(GJ)

		Annual Use per Account								Annual Use	
		Rate 1		Rate 2.1		Rate 2.2		Combined Commercial Rate (Rate 2.1+Rate 2.2)		Rate 25 *	
	Year	Actual	Normal	Actual	Normal	Actual	Normal	Actual	Normal	Actual	Normal
	1995	162.1	153.2	780.7	738.6	7,949.2	7,449.2	828.4	788.8	279,000	279,000
	1996	174.9	156.4	776.4	690.7	9,134.5	8,134.5	823.4	736.5	341,000	341,000
	1997	159.2	158.7	709.8	770.9	7,692.3	7,692.3	748.6	742.9	339,000	339,000
	1998	155.4	163.8	698.0	737.2	9,167.5	9,217.3	745.8	784.9	307,988	308,000
	1999	155.5	161.4	696.6	721.2	7,298.5	7,165.0	732.8	760.3	261,165	264,000
	2000	154.5	158.0	701.0	737.0	6,491.5	6,844.9	732.4	771.8	286,118	286,000
	2001	167.8	167.8	681.0	709.2	3,942.5	4,500.0	793.7	839.5	316,788	321,000
	2002	159.5	154.2	592.3	584.8	4,669.9	4,692.3	746.2	735.2	425,499	416,000
Projected	2003	-	158.7	-	599.6	-	3,385.2	-	-	-	410,000
Forecast	2004	-	157.6	-	601.9	-	3,400.0	-	-	-	412,000

* For 1995 and 1996, Rate 3.2 volumes have been combined with the Rate 25 customer data for proper comparison.

5.2 *Please describe the process used in normalizing use per account.*

Response

The Normalization Process for Fort Nelson Residential and Commercial Usage is the same as that applied in the Lower Mainland, Inland and Columbia Service Areas. It is modeled by fitting the best curve to historical weather and consumption data, with normal temperature values based on 10 year rolling averages.

The resulting equations are used to adjust actual consumption to theoretically normal values.

5.3 *Tab 6, page 4 states that five factors are considered in making projections on use per account by rate class*.

5.3.1 *Please describe which of the five factors, if any, are not applicable to the residential rate class. For example, has there been substantial increase in multiple-unit housing in Fort Nelson to require specific forecast on use for new customer additions*?

Response

The analysis of the Residential Rate Class considers all factors listed on page 4, Tab 6, except rate migration. Migration to and from Residential Rate Classes is not significant.

In response to the specific question concerning the proportion of multiple-unit housing, Terasen Gas believes such an eventuality unlikely in the short term. The reason is two-fold: the proportion of households in apartments and multi-unit housing in Fort Nelson has been historically low, and the number of new houses per year is not high enough to significantly erode this statistic in 2004.

Therefore, given the very small impact of new customer consumption on the mean, a specific forecast for this group was not deemed necessary.

5.3.2 *Please explain how the 158.7 GJ (2003) for Rate 1 customers was projected*.

Response

The value of 158.7 GJ was obtained by projecting actual 2003 monthly use per account from June 30th. Normalized consumption was 87.0 GJ from January to June 2003 while usage from July 1st through December 31st was estimated at 71.7 GJ. Together, the two values add to 158.7GJ.

It is worth noting that an historical difference exists between average use in the first and last 6 months of the year. Typical usage between January and June is usually 54 % of the annual total.

Overall, a regression model is used to predict monthly usage with actual gas cost and monthly temperature as covariates. Projections themselves use actual 2003 gas cost and 1993-2002 normal monthly temperatures.

5.3.3 *Please describe the forecasting steps that result in 157.6 GJ for 2004.*

Response

This value is determined by adding the 12 individual forecasts of monthly usage in 2004. The linear regression model referred to in Question 5.3.2 determines each monthly forecast. The forecast itself used a $ 5.00 Cdn per GJ gas cost and 1993-2002 normal monthly temperatures as input. The month by month results are listed below in Table 5.3.3.

Table 5.3.3

Period	***Predicted Usage***
Jan-04	28.4
Feb-04	21.4
Mar-04	14.2
Apr-04	9.0

May-04	6.5
Jun-04	5.3
Jul-04	4.8
Aug-04	5.3
Sep-04	7.0
Oct-04	10.6
Nov-04	18.4
Dec-04	26.6
Annual	**157.6**

5.4 *The table on Tab 6, page 5 shows the forecast weighted average usage for Rate 2.1/2.2 customers used to develop the revenue forecast. Please confirm that small commercial customers (Rate 2.1) and large commercial customers (Rate 2.2) have the same cost per GJ for all years between 1995 through 2004. If not, please show their average usage separately*.

Response

The rates for Schedules 2.1 and 2.2 have been the same since January 1, 1997. Before that there was a commodity cost difference between the two rates based on the long-term gas supply contract. The average usage is reported separately for Rates 2.1 and 2.2 in Tables 5.1B (Normal) and 5.1A (Actual).

6.0 Gas Sales & Transportation Volumes for 2004 - Energy Forecast

Reference: Application, Section C, Tab 6, pp. 5-7

6.1 *Tab 6, page 5 states that energy use for commercial customers is expected to rise by 3.5 percent in 2004 due largely to modest improvements in the regional economic outlook*.

6.1.1 *Please describe what portion of the 3.5 percent growth can be attributable to growth in use per account and what portion to growth in customer additions*.

Response

Since the account change from 2003 to 2004 is small, and advances in appliance efficiency imply downward pressure on new customer gas use, about

3.2 % may be attributed to growth in use per account alone. Growth in customer additions accounts for most of the remaining 0.3%.

6.1.2 *Please reconcile this observation on improvements in the regional economic outlook with the statement on Tab 6, page 3 that "the relatively low population base, coupled with limited, regionally depressed employment prospects will work to keep any recovery modest."*

Response

These two statements may be reconciled if the 3.5% annual improvement is considered comparatively modest. While this is robust growth compared with other Terasen Gas Service Areas, historical fluctuations in commercial energy demand are frequently much higher in Fort Nelson.

For example, the absolute energy variance from 2000 to 2001 was over 6.9% and the change from 2001 to 2002 was almost 11%. When compared with such historical variations, the 2004 improvement is modest – for reasons specified on page 3, Tab 6.

6.2 *Tab 6, page 6 states that a limited industrial base coupled with uncertainty will work to keep demand relatively flat beyond 2004*.

6.2.1 *Please explain what the uncertainty is and its corresponding risk to forecasting industrial load.*

Response

Please note that the sentence quoted above from the Application, Tab 6, page 4 is incorrect. The sentence in the Application should read "… will work to keep demand relatively flat <u>into</u> 2004".

The degree of uncertainty depends on the economic circumstances facing the Fort Nelson Rate 25 customers. Since both customers produce forest products, there are at least two risks to consider. One is the continuing dispute with the United States over tariffs on various lumber products; the other is fluctuation in market prices that impact plant production. The latter effect is exacerbated by the rapid rise in the Canadian Dollar.

While Terasen Gas does not try to assume anything more than general trends for the region, improvement in industrial demand will depend on buoyant international markets for wood products as well as more certain access to these markets. Neither of these two factors provides any ground for great optimism since prices are high and access to the U.S. market is curtailed.

Of the two customers, one represents about 95% of the current industrial load. As this customer manufactures veneer and sheathing products for home construction, any serious curtailment of access to the U. S. construction market could have adverse effects on gas usage.

Terasen Gas Industrial Marketing Managers also confirmed the 2004 demand outlook with both Fort Nelson industrial customers. Both stated that their 2004 volumes will closely resemble those in 2003.

6.2.2 *Please provide a sensitivity analysis for the industrial energy forecast to justify that 412 TJ for 2004 is the most likely scenario*.

Response

Terasen Gas believes that industrial demand should be estimated by the customers. As both Fort Nelson customers reported that 2004 consumption will approximate 2003 levels, their respective consumption histories were analyzed in support of this claim. This entailed a projection of monthly energy from January 1999 to August, 2003[4].

The 2003 year end projection was found to be about 410 TJ. Given the expectation of both customers, a similar value for 2004 is implied. Although even this statistic is high given the historical average and range presented in Table 6.2.2 below[5], it is a valid statistic for 2004 load – assuming little change from 2003.

Table 6.2.2A – Historical Volumes (Rate 25)

	Total Energy (TJ)	
Lowest (1999)	**Average 1996-2002**	**Highest (2002)**
264	313	415

The 2004 Fort Nelson Industrial Load was also estimated from the 2003 Year-end Projection Model. This calculation shows a significant load decline in 2004 – a result that contradicts stated customer expectation. To validate this initial result, an alternative forecasting method was also applied to monthly load data. Table 6.2.2B summarizes and compares results.

Table 6.2.2B – Volume Sensitivity Analysis

2004 Forecast ARIMA	2004 Forecast Exponential
386 TJ	438 TJ

[4] A statistically adequate ARIMA (2, 0, 0), (2, 1, 0) model was used.
[5] The standard deviation of the mean is approximately 51 TJ.

Since it is difficult to choose between the two forecasts in Table 6.2.2B, their mean is used instead. This produces an estimate of 412 TJ – an outcome that also conforms to stated customer expectations of similar load in 2003 and 2004. The two forecast results may be seen as nominal upper and lower limits of expectation.

7.0 Gas Sales & Transportation Revenues for 2004 - RSAM Proposal

Reference: Application, Section C, Tab 7, pp. 2-3

7.1 *Please provide the historical allowed and achieved ROE for the Fort Nelson service area for each of the years from 1995 to 2003.*

Response

The historical ROE is presented in the table below.

Fort Nelson Service Area
Allowed, Achieved and Normalized Achieved ROE

Year	Allowed ROE	Achieved ROE	Normalized Achieved ROE
(1)	(2)	(3)	(4)
1995	12.000%	15.515%	13.394%
1996	11.000%	18.242%	13.576%
1997	10.250%	11.515%	11.303%
1998	10.000%	12.939%	10.455%
1999	9.250%	5.848%	6.848%
2000	9.500%	3.970%	6.818%
2001	9.250%	-1.576%	0.667%
2002	9.130%	-1.455%	-1.606%
2003	9.420%		

7.2 *For those years where there are significant variations to return on common equity, please comment on the extent that the variations were being caused by margin variations resulting from the variances in use per account forecasts or industrial energy forecasts*.

Response

For 1999 and 2000, the margin variations resulting from variances in use per account forecasts or industrial energy forecast were the primary cause of the Company's inability to earn the allowed return on common equity. For 2001 and 2002, lower sales margins, higher rate base due primarily to the large build up in GCRA account, and increases in operating expenses all contributed to the lower than allowed return on common equity. An RSAM account would have allowed the Company to achieve the allowed return on common equity in two of these four years. In the other two years it would have improved the Company's achieved ROE, since the RSAM captures margin variances based on actual results, although the improvement would not have been large enough for the Fort Nelson Service Area to achieve the allowed return.

7.3 *Further to the description of the proposed RSAM, please explain how the use per customer for residential and commercial customers, and the forecast delivery margin for Rate 25 customers, will be established for years after 2004 if Terasen does not file a revenue requirements application for these years. Are there special circumstances that could justify adjustments to these forecasts*?

Response

Terasen Gas intends to use the most recently approved residential and commercial use rates in years where a revenue requirement application is not filed. The Company would also use the most recent approved Rate 25 total volume and margin as the basis for the RSAM calculation in such years. Residential and Commercial use per customer and Rate 25 forecasts would, in general, have to be adjusted in the context of a revenue requirement application. It is possible for particular circumstances to occur where use rate changes or Rate 25 forecast changes could be offset against an unanticipated change in a cost of service item (e.g. a tax rate change) but Terasen Gas would file an application for the adjustments if such circumstances were to arise.

7.4 *Considering the somewhat different mechanism for Rate 25 customers, and to avoid cross-subsidization, would it be appropriate for Rate 25 customers to have a class-specific RSAM and rider? If not, please provide a sensitivity analysis that justifies the use of a single RSAM rider for all classes across a reasonably wide range of possible circumstances*.

Response

While the Application was for a single RSAM rider to be applicable to all rate classes, Terasen Gas is not opposed to having a class-specific RSAM and separate rider for Rate 25. It is difficult to determine for Fort Nelson whether cross-subsidization would be occurring or not in the case where one RSAM rider applies to all classes since there has never been a Fort Nelson Service Area rate design proceeding. However the Commission has historically ordered that the revenue deficiency arising from customer use rate changes or industrial revenue changes be shared across all rate classes in other service areas in British Columbia.

8.0 Cost of Gas Sold

Reference: Application, Section C, Tab 8, p. 1

8.1 *Please explain the unaccounted-for gas cost of -0.4 percent, and provide the actual unaccounted-for experience for the past three years*.

Response

The unexplained difference between the total measured volumes of gas received from suppliers and the measured volumes delivered to customers and used for company operations is gas unaccounted for. It is generally expressed as a percentage of total delivered sales and transportation service volumes. The forecast unaccounted-for gas of -0.4 percent for the Fort Nelson Service Area for the year 2004 is the average of the annual percentages recorded over 5 calendar years shown in the table below.

Year	Fort Nelson UAF (%)
1998	-2.96
1999	1.76
2000	3.66
2001	-1.06
2002	-3.63
5 Year Average:	-0.446
Rounded to:	-0.4

The negative percentage indicates that Terasen Gas will deliver higher measured volumes than it will receive. Differences may arise from gas vented to the atmosphere and measurement errors."

8.2 *Please explain how the unaccounted-for gas cost is equitably charged or credited to both sales and transportation customers*.

Response

The unaccounted-for gas in total is not readily separable from the incurred gas supply cost. With negative unaccounted-for in the forecast, sales customers benefit from the anticipated lower gas costs needed to deliver their gas as well as transportation customers' gas. It translates into a lower required unit cost of gas to recover the gas purchase costs from the sales customers. Overall, the cost or credit is insignificant and the associated cost end-up in the Gas Cost Reconciliation Account.

There is no separate line item charge for UAF gas costs for transport customers, however there are charges for being out of balance on transport customer deliveries versus nominations.

To properly assess the fairness of rates, a rate design review would be required. The potential benefits to be gained from any redistribution of cost recovery resulting from such a review would have to be balanced against the cost relating to the review.

9.0 Operating and Maintenance Expenses

Reference: Application, Section C, Tab 9, p. 2

9.1 *Please provide a comparative schedule, using a format similar to that in Tab 9, page 2, for the calendar years 1995 to 2004. For 2000 through 2003 include a first level of detail breakout for Direct Fort Nelson costs*.

Response

The following table sets out the comparative information for 1995 to 2004.

TERASEN GAS INC - FORT NELSON SERVICE AREA
OPERATION & MAINTENANCE EXPENSES
FOR THE YEARS 1995 - 2004
($000)

Particulars	1995	1996	1997	1998	1999	2000	2001	2002	2003 Forecast	2004 Forecast
Direct Fort Nelson Costs	216	286	297	247	246	223	238	223	242	242
CustomerWorks (2003-2004)									116	116
Total Fort Nelson Direct Costs	216	286	297	247	246	223	238	223	358	358
Gross O&M			152,398	155,947	144,612	147,567	158,686	170,113	176,915	176,915
Deduct Common Costs accounted for as Direct Costs										
Distribution			(24,180)	(50,683)	(30,654)	(34,346)	(35,368)	(34,012)	(34,972)	(34,972)
Network Development & Operations Support (2001-2004)							(13,214)	(16,163)	(12,480)	(12,480)
Operations Support (1999-2000)					(17,418)	(12,937)				
Customer Services (1995-1998)			(37,773)	(9,151)						
CustomerWorks (2003-2004)									(42,000)	(42,000)
BC Hydro Service Agreements (1995-2001)			(9,091)	(10,677)	(10,819)	(10,674)	(10,899)	-		
Vehicles			(2,012)	(1,415)	(1,698)	(517)	(483)	(386)	(398)	(398)
Overheads Capitalized (1995-2002)			(18,507)	(15,322)	(17,540)	(14,676)	(15,539)	(16,851)		
Common Costs for O&M Allocation			60,835	68,699	66,483	74,417	83,183	102,701	87,065	87,065
Fort Nelson Allocation %			0.40%	0.44%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
Costs Allocated to Fort Nelson	253	221	243	302	266	298	333	411	348	348
Fort Nelson Gross O&M (excl O/H capitalized)									706	706
Add estimated 2004 inflation at 1.9%										13
Fort Nelson Gross O&M									706	719
less O/H Capitalized at 16%									(113)	(115)
Fort Nelson Net O&M	469	507	540	549	512	521	571	634	593	604

The following table provides a first level of detail breakout for direct costs.

TERASEN GAS INC - FORT NELSON SERVICE AREA
DIRECT OPERATION & MAINTENANCE EXPENSES
FOR THE YEARS 2000 - 2003
($000)

Particulars	2000	2001	2002	2003 Forecast
M&E Labour	35	59	54	60
OPEIU Labour	35	38	41	39
IBEW Labour	96	84	76	86
Total Labour	166	181	171	185
Vehicles	11	38	33	33
Employee Expenses	11	10	11	11
Materials	8	8	4	8
Computer Costs	-	2	-	-
Fees & Admin Costs	8	6	6	6
Contractors	17	(4)	2	2
Facilities	4	3	-	3
Recoveries	(2)	(6)	(4)	(6)
Total Non-Labour	57	57	52	57
Fort Nelson Net O&M	223	238	223	242

9.2 *Please provide a detailed explanation for any significant year over year changes (i.e. other than normal inflationary increases) in Direct Costs*.

Response

The following explains the increase in Direct Costs from 1995 to 1996, the only year with significant increase greater than inflation.

Direct Cost - Explanation of Significant Increases	
1995 - 1996 $ 70k	
Increased salaries charged	53
Increased System Operations support cost	44
Increased wages charged out	(15)
Reduced maintenance activity	(20)
Other operating activities	8
	70

9.3 *Please explain why Fort Nelson considered throughput volumes to be the appropriate allocation basis for Terasen Gas Inc. Common O&M costs in 2003 and prior years. Do the same reasons support the use of this methodology for the 2004 Test Year*?

Response

The allocation of inter-company/division costs was addressed in the 1992 BC Gas hearing. In accordance with the BCUC Decision dated August 5, 1992 (page 65) the Commission accepted the 1992 allocation of joint costs based on firm sales volumes. Since 1992, the Company has been allocating corporate costs (apart from specific divisional costs) to Fort Nelson via throughput volumes.

The Company believes that the methodology of allocating corporate costs via throughput volumes continues to be appropriate for the 2004 Test Year.

9.4 *Please provide O&M expense per customer metrics for the calendar years 1995 to 2004*.

Response

The table below shows the total Net O&M expense and per customer information for the years 1995 to 2004.

Year	Total Net O&M ($000)	Average Customer	Nominal Net O&M Per Customer ($)	Real 2003 $ Net O&M Per Customer ($)
1995 Actual	469	1794	261	290
1996 Actual	507	1911	265	292
1997 Actual	540	2000	270	295
1998 Actual	549	2041	269	293
1999 Actual	512	2070	247	267
2000 Actual	521	2047	255	269
2001 Actual	571	2049	279	290
2002 Actual	634	2069	306	312
2003 Projection	593	2104	282	282
2004 Forecast	604	2125	284	279

9.5 *Please provide the source for the 1.9 percent inflation adjustment for the 2004 Test Year.*

Response

CPI for the Province of BC is used as the inflation adjustment factor. The 1.9 percent is the average of the CPI forecast from the following sources.

Source	Forecast Date	CPI % Change
RBC Financial Group	Spring 2003	2.4%
The Toronto-Dominion Bank	July 30, 2003	1.5%
Conference Board of Canada	July 16, 2003	1.7%
B.C. Ministry of Finance	March 2003	2.0%
Average		**1.90%**

9.6 *Please provide the excerpt from the CustomerWorks contract showing the cost of $54.54 per customer applicable to Fort Nelson. What escalation provisions regarding this cost are included in the contract? When does the contract expire*?

Response

The Client Services Agreement between CustomerWorks Limited Partnership and BC Gas Utility Ltd. (now Terasen Gas Inc.) is included as Appendix 1 of the December 21, 2001 Application for the Disposition of Property and Approval of Customer Care Agreements. This information is available on request. Although the cost of $54.54 per customer is not specifically shown in the Client Services Agreement, total costs for each service are shown in the Schedules attached to the Agreement. A summary of the cost categories used to derive the $54.54 cost per customer are as follows:

		2003 to 2006
Schedule A	Customer Contact Services	$16,857,047*
Schedule B	Billing Support Services	$17,622,210
Schedule C	Meter Services	$ 5,063,309
Schedule D	Credit and Collection Services	$ 2,045,062
Schedule E	Industrial and Off System Support Services	$ 404,667
	Total Cost	$41,992,295
	Number of Customers (per contract)	770,000

Cost per Customer	$	54.54

The Client Services Agreement was filed with the Commission in draft form with slightly different figures in Schedule A. The final agreement includes $16,857,047 for each year from 2003 to 2006.

These costs apply to all Terasen Gas customers including Fort Nelson customers. There are no escalation provisions in the contract during the initial five-year term. The contract term is five years from January 1, 2002 until December 31, 2006 with renewal provisions. In the case of renewal, the contract could be extended on a year-to-year basis with per customer cost increases limited to one-half of CPI.

9.7 *Please describe the specific services that are included in the cost of $54.54 per customer. Will Fort Nelson require all the included services in the 2004 Test Year to carry out utility operations*?

Response

The services are broadly described in the response to Information Request No. 9.6. A detailed description covers several pages, as shown in Appendix 1 of the December 21, 2001 Application for the Disposition of Property and Approval of Customer Care Agreements.

Fort Nelson does require all of the included services in the 2004 Test Year to carry out utility operations.

10.0 Overheads Capitalized

Reference: Application, Section C, Tabs 3 and 9

10.1 *Overhead of $115,000 for 2004 is shown on Tab 3, page 2.1. This is consistent with Tab 9, page 2 which calculates overheads capitalized at 16 percent, but is a significant increase from Overhead of $67,000 per year in 2002 and 2003. How were the Overhead amounts for 2003 and all prior years back to 1995 determined? Using the methodology for 2002 and 2003, what would be the corresponding amount of Overhead for 2004*?

Response

As mentioned in the response to Question 1.7 the annual overhead for Fort Nelson for 2003 and before has been an allocation of the Terasen Gas total overhead based on Fort Nelson’s percentage of total Company sales and transportation volumes. If the methodology for 2002 and 2003 were used to calculate the 2004 overhead, the amount would be $69,000. If the previous approach to the determination of the Fort Nelson overhead capitalized was applied in 2004 the 2004 revenue deficiency would increase by about $44,000 since more of the gross operating and maintenance expense would be booked as a current period expense.

10.2 *The Application requests confirmation of an overhead capitalization rate of 16 percent, which is the rate that was found to be appropriate for other Terasen service areas. If there are other reasons that support a 16 percent overhead capitalization rate, please provide them*.

Response

There are two main reasons that support the 16 percent overhead capitalization rate:

1. Maintain consistency among all services area for both Regulatory and Accounting purposes.
2. Due to the integrated nature of the operations at Terasen Gas, many costs are shared by all service areas.

11.0 Income Taxes

Reference: Application, Section C, Tab 13, p. 1

11.1 *Please provide the individual tax rates (i.e. federal, provincial, etc.) comprising the combined forecast corporate income tax rate of 35.62 percent*.

Response

The table below shows the individual tax rates comprising the combined 2004 forecast corporate income tax rate of 35.62 percent.

Federal Tax Rate	21.00%
B.C. Provincial Tax Rate	13.50%
Subtotal	34.50%
Federal Surtax	1.12%
Total Corporate Income Tax Rate	35.62%

Reference: Application, Section C, Tab 13, p. 5

11.2 *Please reconcile the 2004 net additions of $296,000 to the 2004 gross plant additions of $347,000 in Tab 3, page 2.1.*

Response

The 2004 net UCC additions of $296,000 should be $344,000. In determining the 2004 UCC additions, the previous year's overhead was used instead of the

2004 amount. The effect on the 2004 CCA is an increase of $1,000 from the filed application. This revision results in a reduction of the revenue requirement deficiency by $1,000.