Scott A. Thomson
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October 31, 2003

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

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

Dear Sir:

RE: Terasen Gas Inc.
2004 – 2007 Performance Based Rate Plan
2003 Annual Review - November 21, 2003
Terasen Gas Centre, Georgia Room - 9:00 a.m.
BCUC Order No. G-66-03

By BCUC Order No. G-66-03, the British Columbia Utilities Commission ("the Commission") set November 21, 2003 as the date for the 2003 Terasen Gas Inc. Annual Review. This Annual Review will be the first under the Company's 2004 – 2007 Multi-Year Performance Based Rate settlement agreement ("the Settlement"). The Settlement was approved by BCUC Order No. G-51-03 dated July 29, 2003. The Commission's approval of the Settlement followed a public hearing and Commission Decision on the Company's 2003 Revenue Requirement Application, an April 17, 2003 Application for a Multi-Year Performance Based Rate Plan for 2004-2008, information requests and responses and a negotiated settlement process in June and July 2003.

The terms of the Settlement require Terasen Gas to submit to the Commission and interested parties advance materials on the information to be presented at the Annual Review three weeks prior to the Annual Review. The details of Annual Review process are set out at Pages 17 to 22 of Appendix A of BCUC Order No. G-51-03. The 2003 Annual Review is a process for the Company and stakeholders to ensure that the objectives of the Settlement are being achieved and to review the cost drivers and financial forecasts for the purposes of establishing the 2004 revenue requirements.

Enclosed are fifteen (15) copies of the advance information for the 2003 Annual Review. This includes information on the cost drivers, and financial projections and forecasts necessary for setting delivery rates for 2004 in Section A of the binder, and, in Section B of the binder, various other reports and information identified in the Settlement and BCUC Order No. G-51-03. Terasen Gas will present information at the Annual Review on the matters addressed in the advance materials.

The 2004 revenue requirement increase identified in the enclosed materials, is $17.4 million, equivalent to a 3.71% increase in gross margin, or a 1.25% increase in total revenue at existing rates. The volume and revenue forecast influenced strongly by declining customer use rates is the largest contributor to the revenue requirement increase, accounting for about $11.6 million or about two thirds of the total increase. This and other contributors to the increase are summarized at Tab A-1, Page 9.

The revenue requirement information included is based on an estimate of the 2004 return on equity ("ROE") at 9%. Variances from this assumed ROE arising from the Commission's generic ROE mechanism will lead to corresponding changes in the final 2004 revenue requirement applied for. Any rate changes related to the flow-through of gas cost changes will be dealt with in a separate application to the Commission although an outlook for such commodity-related changes will be provided at the Annual Review.

As a final note, under the terms of the Settlement, Terasen Gas is required to file a copy of an independent external auditor's report on its review of the Company's compliance with the Code of Conduct and Transfer Pricing Policy. This report includes a review of the annual compliance work conducted by Terasen Gas' Internal Audit Services regarding the Code of Conduct and Transfer Pricing Policy. Terasen Gas has contracted the firm KPMG to act as the external auditors. KPMG is in the process of finalizing its report which will be attached to the report of Internal Audit Services included in the enclosed advance material. KPMG have confirmed that the report will be available prior to the Annual Review and Terasen Gas will forward it as soon as it is received...

We trust the enclosed is satisfactory. Should additional copies of the advance material be required, please contact Chi Le at (604) 592-7664 or email at chi.le@terasen.com. Also, to assist in the planning of the review, it would be appreciated if you can contact Chi and provide her with an indication of your attendance on November 21, 2003.

Yours very truly,

TERASEN GAS INC.

Original signed by Scott Thomson

Scott Thomson

c.   2004 – 2007 PBR NSP Participants

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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November 12, 2003

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

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

Dear Sir:

RE: Terasen Gas Inc.
2004 – 2007 Performance Based Rate Plan
2003 Annual Review - November 21, 2003
BCUC Order No. G-66-03
External Auditor's Report on Code of Conduct and Transfer Pricing Policy

In the cover letter of Terasen Gas' October 31, 2003 filing of 2003 Annual Review advance materials the Company indicated that the independent external auditor's report on the Company's compliance with the Code of Conduct and Transfer Pricing Policy was not yet complete and would be forwarded to the Commission and interested parties when it was available.

This report is now complete and Terasen Gas encloses 15 copies for insertion in Section B, Tab 7 (behind Terasen Gas' Internal Audit Services report) of the binders of the advance material provided to the Commission on October 31, 2003.

Yours very truly,

TERASEN GAS INC.

Original signed by Scott Thomson

Scott Thomson

Encl.

c. 2004 – 2007 PBR NSP Participants
Interested Parties

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2004 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

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SECTION A-1 INDEX

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
SUMMARY OF REVENUE REQUIREMENTS
FOR THE YEAR ENDING DECEMBER 31, 2004

By Order No. G-51-03 dated July 29, 2003, the Commission approved the Negotiated Settlement of the Terasen Gas Inc. Multi-Year Performance Based Rate Plan for 2004 – 2007.

Pursuant to the provisions of the Settlement Agreement, Terasen Gas has developed the projections and forecasts needed to establish the 2004 revenue requirement. The attached costs and revenues incorporate updated data for

- 2003 projected year-end customers,
- 2003 projected year-end plant balances and other rate base information,
- 2003 projected deferral account balances and amortization,
- Other projected 2003 cost-of-service items required under the terms of the Settlement for the setting of 2004 rates
- 2004 forecast cost drivers, such as customer growth, average total customers and inflation,
- 2004 customer use rate forecasts,
- 2004 forecast volumes and revenues,
- 2004 formula-based utility O&M expenses including adjustments as per the terms of the Settlement for the change in accounting for Transmission Pipeline Integrity Program ("TPIP") costs, and pension and insurance forecast cost increases,
- 2004 formula-based base capital expenditures and resulting plant balances, accumulated depreciation and contributions-in-aid-of-construction,
- 2004 forecast property taxes ,
- 2004 forecast working capital, deferred account balances and amortization, and
- 2004 forecast long-term debt and long-term and unfunded debt costs to be included in 2004 rates.

A summary of the 2004 revenue requirement increase determined pursuant to the terms of the Settlement Agreement and the Revised Target is shown on the following financial summary pages:

Page 4 Summary of Rate Increase Required

Page 5 Utility Rate Base

Page 6 Utility Income and Earned Return

Page 7 Income Taxes / Revenue Deficiency

Page 8 Return on Capital

The 2004 test year costs and revenues are explained under the following section of this Annual Review material:

- Cost Drivers - see Section A, Tab 2,
- gas plant in service, plant additions and other rate base components - see Section A, Tab 3,
- volumes and revenues - see Section A, Tab 4 ,
- operating and maintenance costs - see Section A, Tab 5,
- taxes, financing costs, etc. - see Section A, Tab 6, and
- 2003 projected results - see Tab 7.

The results of incorporating the forecast and formula-based costs and revenues in the 2004 test year show that the revenue requirement increase is $17.4 million, equivalent to a 3.71% increase in gross margin, or a 1.25% increase in total revenue at existing rates.

The volume and revenue forecast is the largest contributor to the $17.4 million revenue requirement increase, accounting for about $11.6 million or about two-thirds of the total increase. The decline in use rates for residential and commercial rate classes is the major factor and this is discussed in more detail in Section A, Tab 4. Other factors contributing to the remaining $5.8 million revenue requirement increase are summarized on Page 9 of Section A, Tab 1.

In addition to the delivery rate changes arising from the $17.4 million revenue requirement increase, customers will also experience rate changes in 2004 related to flow-through of cost of gas and GCRA rider changes, RSAM rider changes and discontinuation of the ten-month rider to recover the January and February portion of the approved 2003 rate increase. The current outlook for commodity costs and the GCRA rider are for a rate decrease to be passed through on January 1, 2004. This comment should be qualified with the considerable volatility in natural gas commodity markets in which a cold weather snap or unexpected negative news can change the commodity market outlook quite quickly. The removal of the ten-month rider will decrease residential rates by $0.043 per gigajoule while the RSAM rider is expected to go up from the 2003 level by $0.057 per gigajoule. The net effect for residential customers of the ten-month rider removal and RSAM rider increase is an increase of 0.1% of the annual bill.

The final rates for 2004 may be subject to further adjustments for changes in the allowed return on common equity ("ROE"). The financial calculations for 2004 in the enclosed materials have been made using an ROE of 9.0%, a recent estimate of the ROE that would be in effect if ROE were set using current Long Canada Bond yields. Further revisions to the rates relating to the approved ROE for 2004 varying from 9.0% will be in addition to the rate adjustments reflected in these Annual Review advance materials.

TERASEN GAS INC.

SUMMARY OF RATE INCREASE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004 Core	2004 Non-Core	2004 Bypass and Special Rates	2004 Total	Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RATE INCREASE REQUIRED						
2							
3	Gas Sales and Transportation Revenue,						
4	At Prior Year's Rates	$1,213,907	$1,316,493	$51,876	$11,932	$1,380,301	$166,394
5							
6	Add - Other Revenue Related to SCP Third Party						
7	Revenue / Terasen Gas (Vancouver Island)	12,443	0	0	12,845	12,845	402
8							
9	Total Revenue	1,226,350	1,316,493	51,876	24,777	1,393,146	166,796
10							
11	Less - Cost of Gas	(759,132)	(921,326)	(1,863)	(804)	(923,993)	(164,861)
12							
13	Gross Margin	$467,218	$395,167	$50,013	$23,973	$469,153	$1,935
14							
15	Revenue Deficiency	$13,541	$15,439	$1,954	$0	$17,393	
16							
17	Revenue Deficiency as a % of Gross Margin	2.90%	3.91%	3.91%	0.00%	3.71%	
18							
19	Revenue Deficiency as a % of Total Revenue	1.10%	1.17%	3.77%	0.00%	1.25%	

TERASEN GAS INC..

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004 Existing Rates	2004 Adjustments	2004 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$2,711,233	$2,816,944	$0	$2,816,944	$105,711	- Tab 3, Page 7.1
2	CPCNs	31,845	10,117	0	10,117	(21,728)	- Tab 3, Page 7.1
3							
4	Additions	115,430	112,914	0	112,914	(2,516)	- Tab 3, Page 7.1
5	Disposals	(13,067)	(21,139)	0	(21,139)	(8,072)	- Tab 3, Page 7.1
6							
7	Plant in Service, Ending	2,845,441	2,918,836	0	2,918,836	73,395	
8							
9	Add - Intangible Plant	837	837	0	837	0	
10							
11		2,846,278	2,919,673	0	2,919,673	73,395	
12							
13	Contributions In Aid of Construction	(147,888)	(149,325)	0	(149,325)	(1,437)	- Tab 3, Page 8
14							
15	Less - Accumulated Depreciation	(527,002)	(566,585)	0	(566,585)	(39,583)	- Tab 3, Page 13
16							
17							
18	Net Plant in Service, Ending	$2,171,388	$2,203,763	$0	$2,203,763	$32,375	
19							
20							
21	Net Plant in Service, Beginning	$2,138,353	$2,177,251	$0	$2,177,251	$38,898	- Tab 3, Page 9
22							
23							
24	Net Plant in Service, Mid-Year	$2,154,871	$2,190,507	$0	$2,190,507	$35,636	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(1,000)	(750)	0	(750)	250	
27	Work in Progress, No AFUDC	4,000	4,000	0	4,000	0	
28	Unamortized Deferred Charges	31,076	25,610	0	25,610	(5,466)	- Tab 3, Page 11.1
29	Cash Working Capital	(13,061)	(19,104)	305	(18,799)	(5,738)	- Tab 3, Page 12
30	Other Working Capital	98,485	101,177	0	101,177	2,692	- Tab 3, Page 12
31	Deferred Income Tax, Mid-Year	(364)	(364)	0	(364)	0	
32	Capital Efficiency Mechanism	(1,381)	0	0	0	1,381	
33	LILO Benefit	(2,265)	(1,510)	0	(1,510)	755	
34	Utility Rate Base	$2,270,361	$2,299,566	$305	$2,299,871	$29,510	

TERASEN GAS INC..

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004 Existing Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	126,035	120,165	0	120,165	(5,870)	- Tab 4, Page 11
3	Transportation	125,717	131,274	0	131,274	5,557	- Tab 4, Page 11
4		251,752	251,439	0	251,439	(313)	- Tab 4, Page 11
5							
6	Average Rate per GJ						
7	Sales	$9.156	$10.964	$0.000	$11.093	$1.937	
8	Transportation	$0.476	$0.478	$0.000	$0.493	$0.017	
9	Average	$4.876	$5.490	$0.000	$5.559	$0.683	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,154,009	$1,317,543	$0	$1,317,543	$163,534	- Tab 4, Page 12
13	- Increase	12,112	0	15,445	15,445	3,333	
14							
15	Transportation - Existing Rates	59,898	62,758	0	62,758	2,860	- Tab 4, Page 12
16	- Increase	1,429		1,948	1,948	519	
17	**Total**	1,227,448	1,380,301	17,393	1,397,694	170,246	- Tab 4, Page 12
18							
19	Cost of Gas Sold (Including Gas Lost)	759,132	923,993	0	923,993	164,861	- Tab 4, Page 13.1
20							
21	**Gross Margin**	468,316	456,308	17,393	473,701	5,385	
22							
23	Operation and Maintenance	149,294	159,417	0	159,417	10,123	- Tab 5, Page 2
24	Vehicle / Coastal Facilities Lease	6,306	6,372	0	6,372	66	
25	Property and Sundry Taxes	41,213	39,420	0	39,420	(1,793)	- Tab 6, Page 3
26	Depreciation and Amortization	73,076	78,885	0	78,885	5,809	- Tab 6, Page 6
27	Other Operating Revenue	(22,737)	(22,633)	0	(22,633)	104	
28		247,152	261,461	0	261,461	14,309	
29	Utility Income Before Income Taxes	221,164	194,847	17,393	212,240	(8,924)	
30							
31	Income Taxes	41,943	33,616	5,996	39,612	(2,331)	- Tab 1, Page 7
32							
33	**EARNED RETURN**	$179,221	$161,231	$11,397	$172,628	($6,593)	
34							
35	**UTILITY RATE BASE**	$2,270,361	$2,299,566	$305	$2,299,871	$29,510	
36							
37	**RATE OF RETURN ON UTILITY RATE BASE**	7.894%	7.010%		7.506%	-0.39%	

TERASEN GAS INC..

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004 Existing Rates	2004 ----Revised Rates----- Revised Revenue	2004 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$179,221	$161,231	$11,397	$172,628	($6,593)	- Tab 1, Page 6
3	Deduct - Interest on Debt	(108,637)	(104,306)	(13)	(104,319)	4,318	
4	Add- Non-Tax Ded. Expense (Net)	2,191	262	0	262	(1,929)	- Tab 6, Page 5
5							
6	Accounting Income After Tax	72,775	57,187	11,384	68,571	(4,204)	
7	Add (Deduct) - Timing Differences	(13,976)	(6,616)	0	(6,616)	7,360	- Tab 6, Page 5
8	Add - Large Corporation Tax	4,044	3,629	(195)	3,434	(610)	- Tab 6, Page 8
9							
10	Taxable Income After Tax	$62,843	$54,200	$11,189	$65,389	$2,546	
11							
12	Income Tax Rate (Current Tax)	37.620%	35.620%	35.620%	35.620%	-2.000%	
13	1 - Current Income Tax Rate	62.380%	64.380%	64.380%	64.380%	2.000%	
14							
15	Taxable Income (L10 : L13)	$100,742	$84,187	$17,380	$101,567	$825	
16							
17	Income Tax - Current (L12 x L15)	$37,899	$29,987	$6,191	$36,178	($1,721)	
18							
19	- Large Corporation Tax	4,044	3,629	(195)	3,434	(610)	- Tab 6, Page 8
20							
21	Total	$41,943	$33,616	$5,996	$39,612	($2,331)	- Tab 1, Page 6
22							
23							
24	REVENUE DEFICIENCY						
25	Earned Return	$179,221		$11,397	$172,628	($6,593)	- Tab 1, Page 6
26	Add - Income Taxes	41,943		5,996	39,612	(2,331)	- Tab 1, Page 6
27	Deduct - Utility Income Before Taxes,						
28	Existing Rates	(207,623)		0	(194,847)	12,776	- Tab 1, Page 6
29	Corporate Capital Tax	0		0	0	0	
30							
31	Deficiency After Corporate Capital Tax	$13,541		$17,393	$17,393	$3,852	

TERASEN GAS INC..

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2004 PRESENT RATES							
2	Long-Term Debt			$1,315,417	57.20%	7.373%	4.217%	
3	Unfunded Debt			225,292	9.80%	3.250%	0.319%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			758,857	33.00%	7.497%	2.474%	
6								
7				$2,299,566	100.00%		7.010%	
8								
9	2004 REVISED RATES							
10	Long-Term Debt			$1,315,417	57.20%	7.373%	4.217%	$96,986
11	Unfunded Debt		$225,292					
12	Adjustment, Revised Rates		205	225,497	9.80%	3.250%	0.319%	7,329
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			758,957	33.00%	9.000%	2.970%	68,306
15								
16				$2,299,871	100.00%		7.506%	$172,620
17								
18	2003 DECISION							
19	Long-Term Debt			$1,343,432	59.17%	7.558%	4.472%	$101,537
20	Unfunded Debt		$177,451					
21	Adjustment, Revised Rates		259	177,710	7.83%	4.000%	0.313%	7,108
22	Preference Shares			0	0.00%	0.000%	0.000%	0
23	Common Equity			749,219	33.00%	9.420%	3.109%	70,576
24								
25				$2,270,361	100.00%		7.894%	$179,221
26								
27	2004 CHANGE FROM 2003 DECISION							
28	Long-Term Debt			($28,015)	-1.97%	-0.185%	-0.255%	($4,551)
29	Unfunded Debt		$47,841					
30	Adjustment, Revised Rates		(54)	47,787	1.97%	-0.750%	0.006%	221
31	Preference Shares			0	0.00%	0.000%	0.000%	0
32	Common Equity			9,738	0.00%	-0.420%	-0.139%	(2,270)
33								
34				$29,510	0.00%		-0.388%	($6,601)

		($ Millions)
Volumes/Revenue Related		
• Lower use rates for Rates 1/2/3/23	$13.6	
• Customer growth and Industrial revenue changes	(2.0)	$11.6
O & M Related		
• Higher O&M per formula	2.8	
• Change in accounting for TPIP	5.5	
• Pension and Insurance Variance (net of overheads)	1.8	10.1
Other Items		
• Lower Property Taxes	(1.8)	
• Higher Depreciation and Amortization	8.2	
• Lower Interest Expense	(4.3)	
• Lower ROE (9.42% to 9.0%)	(4.8)	
• Large Corporations Tax Rate Reduction	(0.9)	
• Lower Income Tax Rate (37.62% to 35.62%)	(3.1)	
• Higher Rate Base due to Plant Additions	2.4	(4.3)
Total Revenue Deficiency (Section A, Tab 1, Page 4, Column 6, Line 15)		$17.4

TERASEN GAS INC.

**2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2004 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT**

SECTION A-2 INDEX

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
2004 COST DRIVERS

The table below shows the Cost Driver forecasts which are used for setting the 2004 Targets as prescribed in BCUC Order No. G-51-03.

	2003 Projected	2004 Forecast	
Cost Drivers			
Year End Customer Counts	773,654	782,258	
Customer Additions		8,604	Note 1
Average Customers Counts	770,368	777,779	
Change in Average Customers		7,411	Note 2
Percentage of Customer Growth - Average		0.96%	
Escalators			
B.C. Inflation (CPI)		1.70%	Note 3
Adjustment Factor		0.85%	Note 4

Explanatory Notes

Note 1 2003 projection and 2004 forecast year end customer counts are explained under Tab 4 - Volumes and Revenues. Year end customer additions are used to calculate Capital Expenditures driven by customer addition.

Note 2 2004 forecast average customer additions are explained under Tab 4 - Volumes and Revenues. The percentage of average customer growth is used to calculate formula driven O & M Expense and Other Based Capital Expenditures.

Note 3 Pursuant to the provisions of the July 29, 2003 BCUC Decision, the 2004 B.C. inflation forecast will be determined as the average of the forecasts from the Conference Board of Canada, the B.C. Ministry of Finance, the RBC Financial Group, and the Toronto-Dominion Bank.

Based on this formula, the B.C. CPI forecast for 2004 is 1.7%, and represents the average of the forecasts below:

Conference Board of Canada	1.7%	(July 2003)
B.C. Ministry of Finance	2.2%	(September 2003)
RBC Financial Group	1.5%	(Autumn 2003)
Toronto-Dominion Bank	1.5%	(July 2003)

(Copies of the forecasts are attached as Attachment A)

Note 4 Pursuant to the provisions of BCUC Order G-51-03, the adjustment factor will be 50% CPI for 2004.

TAB A-2 2004 COST DRIVERS

ATTACHMENT A

Key Economic Indicators: British Columbia
(Forecast Completed: July 16, 2003)

	2002:1	2002:2	2002:3	2002:4	2003:1	2003:2	2003:3	2003:4	2004:1	2004:2	2004:3	2004:4	2002	2003	2004
GDP at market prices (current $)	130,595	135,072	137,134	140,330	140,686	140,623	140,749	142,420	143,851	145,728	147,486	149,224	135,783	141,120	146,572
	0.6	*3.4*	*1.5*	*2.3*	*0.3*	*0*	*0.1*	*1.2*	*1.0*	*1.3*	*1.2*	*1.2*	*2.1*	*3.9*	*3.9*
GDP at basic prices (current $)	119,287	123,475	125,338	128,290	128,725	128,240	128,359	130,004	131,391	133,231	134,952	136,651	124,098	128,832	134,056
	0.7	*3.5*	*1.5*	*2.4*	*0.3*	*−0.4*	*0.1*	*1.3*	*1.1*	*1.4*	*1.3*	*1.3*	*1.7*	*3.8*	*4.1*
GDP at basic prices (constant $ 1997)	115,490	116,207	117,433	117,455	118,042	118,556	118,708	119,601	120,528	121,553	122,599	123,409	116,646	118,727	122,022
	0.9	*0.6*	*1.1*	*0*	*0.5*	*0.4*	*0.1*	*0.8*	*0.8*	*0.9*	*0.9*	*0.7*	*1.9*	*1.8*	*2.8*
Consumer price index (1992 = 1.0)	1.160	1.180	1.187	1.188	1.197	1.204	1.206	1.211	1.216	1.223	1.228	1.233	1.179	1.205	1.225
	0.7	*1.8*	*0.6*	*0.1*	*0.8*	*0.6*	*0.2*	*0.3*	*0.5*	*0.6*	*0.4*	*0.4*	*2.3*	*2.2*	*1.7*
Implicit price deflator— GDP at basic prices (1997 = 1.0)	1.033	1.063	1.067	1.092	1.091	1.082	1.081	1.087	1.090	1.096	1.101	1.107	1.064	1.085	1.099
	−0.1	*2.9*	*0.4*	*2.3*	*−0.2*	*−0.8*	*0*	*0.5*	*0.3*	*0.5*	*0.4*	*0.6*	*−0.1*	*2.0*	*1.2*
Average weekly wages (level)	660.4	657.0	659.4	665.7	665.7	667.1	671.2	675.9	685.8	693.8	700.1	705.1	660.6	670.0	696.2
	0.5	*−0.5*	*0.4*	*1.0*	*0*	*0.2*	*0.6*	*0.7*	*1.5*	*1.2*	*0.9*	*0.7*	*0.3*	*1.4*	*3.9*
Personal income (current $)	111,842	111,997	112,537	113,415	113,987	114,945	115,361	116,113	117,549	119,092	121,020	122,604	112,448	115,101	120,066
	0.9	*0.1*	*0.5*	*0.8*	*0.5*	*0.8*	*0.4*	*0.7*	*1.2*	*1.3*	*1.6*	*1.3*	*1.7*	*2.4*	*4.3*
Personal disposable income (current $)	85,532	86,665	86,391	87,493	87,729	88,402	88,649	89,165	90,688	91,918	93,391	94,591	86,520	88,486	92,647
	1.1	*1.3*	*−0.3*	*1.3*	*0.3*	*0.8*	*0.3*	*0.6*	*1.7*	*1.4*	*1.6*	*1.3*	*3.1*	*2.3*	*4.7*
Personal savings rate	−4.88	−6.31	−7.56	−7.91	−9.29	−10.29	−10.49	−10.68	−10.09	−10.06	−9.83	−9.75	−6.66	−10.19	−9.93
Population of labour force age (000s)	3,307	3,320	3,332	3,341	3,348	3,358	3,367	3,376	3,385	3,394	3,404	3,414	3,325	3,363	3,399
	0.3	*0.4*	*0.4*	*0.3*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.4*	*1.1*	*1.1*
Labour force (000s)	2,129	2,151	2,171	2,180	2,178	2,189	2,197	2,198	2,209	2,217	2,225	2,233	2,157	2,191	2,221
	1.1	*1.1*	*0.9*	*0.4*	*−0.1*	*0.5*	*0.4*	*0*	*0.5*	*0.4*	*0.4*	*0.3*	*2.6*	*1.5*	*1.4*
Employment (000s)	1,940	1,959	1,997	1,997	2,004	2,008	1,997	1,999	2,013	2,027	2,039	2,048	1,973	2,002	2,032
	1.1	*0.9*	*2.0*	*0*	*0.4*	*0.2*	*−0.6*	*0.1*	*0.7*	*0.7*	*0.6*	*0.4*	*1.6*	*1.4*	*1.5*
Unemployment rate	8.8	8.9	8.0	8.4	8.0	8.3	9.1	9.1	8.9	8.6	8.4	8.3	8.5	8.6	8.5
Retail sales (current $)	39,595	40,449	40,260	40,786	41,125	41,242	41,375	41,647	42,173	42,761	43,353	43,834	40,273	41,347	43,030
	2.2	*2.2*	*−0.5*	*1.3*	*0.8*	*0.3*	*0.3*	*0.7*	*1.3*	*1.4*	*1.4*	*1.1*	*6.0*	*2.7*	*4.1*
Housing starts (units)	19,433	20,032	23,616	23,419	23,800	25,070	21,576	20,493	19,428	19,383	19,357	19,348	21,625	22,735	19,379
	9.5	*3.1*	*17.9*	*−0.8*	*1.6*	*5.3*	*−13.9*	*−5.0*	*−5.2*	*−0.2*	*−0.1*	*0*	*25.5*	*5.1*	*−14.8*

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

First Quarterly Report

on the Economy, Fiscal Situation,
and Outlook

Fiscal Year 2003/04
Three Months
April – June 2003

British Columbia
Ministry of Finance
www.gov.bc.ca

Table 2.6.2 Components of British Columbia Real GDP at Market Prices

	2001	2002	2003 (Forecast)	2004 (Forecast)	2005 (Forecast)	2006 (Forecast)	2007 (Forecast)
			1997$ billion; chain-weighted				
Personal Expenditure on Goods and Services	80.3	82.5	83.9	86.5	88.9	91.1	93.5
(% change)	2.9	2.7	1.8	3.0	2.8	2.5	2.6
- Goods	34.7	35.8	36.1	37.2	38.2	39.1	39.9
(% change)	3.2	3.2	0.8	3.2	2.8	2.3	2.0
- Services	45.6	46.7	47.9	49.3	50.6	52.0	53.6
(% change)	2.6	2.3	2.5	2.9	2.8	2.7	3.0
Government Current Expenditures on Goods and Services	24.7	24.9	24.7	24.3	24.4	25.0	25.6
(% change)	5.7	0.8	-0.7	-1.9	0.7	2.2	2.3
Investment in Fixed Capital	25.4	25.2	26.1	27.3	29.0	29.9	31.2
(% change)	5.4	-0.9	3.9	4.6	6.1	3.0	4.5
Final Domestic Demand	**130.4**	**132.6**	**134.8**	**138.0**	**142.2**	**145.9**	**150.1**
(% change)	**3.8**	**1.7**	**1.7**	**2.4**	**3.0**	**2.6**	**2.9**
Exports Goods & Services	55.0	55.4	56.2	57.9	60.0	62.2	64.3
(% change)	-4.3	0.8	1.3	3.1	3.6	3.5	3.5
Imports Goods & Services	60.7	61.9	63.3	65.3	67.4	69.2	71.3
(% change)	1.0	1.9	2.3	3.1	3.3	2.7	2.9
Inventory Change	-0.2	0.4	0.8	1.1	0.9	1.1	0.9
Statistical Discrepancy	-0.3	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Real GDP at Market Prices	**123.9**	**126.1**	**128.0**	**131.4**	**135.3**	**139.4**	**143.6**
(% change)	**-0.2**	**1.8**	**1.5**	**2.6**	**3.0**	**3.0**	**3.0**

Table 2.6.3 Components of Nominal Income and Expenditure

	2001	2002	2003 (Forecast)	2004 (Forecast)	2005 (Forecast)	2006 (Forecast)	2007 (Forecast)
Labour Income[1] ($ million)	70,044	71,792	73,620	76,690	80,270	84,050	88,070
(% change)	2.4	2.5	2.5	4.2	4.7	4.7	4.8
Personal Income ($ million)	110,258	111,955	115,050	119,730	124,880	130,180	135,860
(% change)	2.6	1.5	2.8	4.1	4.3	4.2	4.4
Corporate Profits Before Taxes ($ million)	10,009	9,821	9,930	10,440	11,290	12,190	13,090
(% change)	-2.8	-1.9	1.1	5.1	8.1	8.0	7.4
Retail Sales ($ million)	37,979	40,273	41,440	43,440	45,440	47,560	49,880
(% change)	6.0	6.0	2.9	4.8	4.6	4.7	4.9
Housing Starts	17,234	21,625	24,140	24,340	24,900	25,690	26,370
(% change)	19.5	25.5	11.6	0.8	2.3	3.2	2.6
Residential Investment[2] ($ million)	7,569	8,997	10,137	10,657	11,126	11,784	12,497
(% change)	11.3	18.9	12.7	5.1	4.4	5.9	6.0
B.C. Consumer Price Index (1992 = 100)	115.2	117.9	120.7	123.3	125.7	128.3	131.0
(% change)	1.7	2.3	2.3	2.2	2.0	2.0	2.1

[1] Domestic basis; wages, salaries and supplementary labour income.
[2] Includes renovations and improvements.

Forecast detail

Average annual % change unless otherwise indicated

	Real GDP		Nominal GDP		Employment		Labour force		Unemployment rate %		Personal disposable income		Housing Starts Thousands		Non-Res. Investment		Retail sales		CPI	
	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004
NFLD.	4.5	2.8	8.5	6.1	1.4	1.5	0.8	1.0	16.4	16.0	4.5	5.0	2.22	1.80	2.0	5.0	5.7	5.6	3.1	1.9
P.E.I	2.0	2.7	4.6	4.0	2.2	2.0	1.8	1.2	11.7	11.0	1.5	4.2	0.98	0.75	0.2	4.2	0.5	4.0	3.8	1.3
N.S.	2.5	2.4	5.4	4.0	1.8	1.3	1.5	1.1	9.4	9.2	2.1	3.2	5.89	4.89	1.0	4.8	1.7	4.5	3.6	1.2
N.B.	2.6	3.0	5.7	4.0	0.2	1.4	0.5	1.0	10.7	10.3	1.3	4.3	4.20	3.84	7.0	3.5	0.9	4.4	3.2	1.0
QUE.	1.9	3.5	4.7	4.3	1.5	1.4	2.1	1.3	9.1	9.0	3.1	4.5	45.92	38.57	1.5	5.5	5.0	4.9	2.4	1.4
ONT.	1.6	3.6	4.2	4.5	2.4	1.1	2.4	1.3	7.1	7.3	3.8	4.8	81.50	72.38	1.1	4.7	3.9	5.2	2.2	1.5
MAN.	2.7	3.3	4.9	3.0	0.7	1.2	0.4	1.7	4.9	5.3	4.2	2.2	3.58	3.30	1.3	2.5	2.3	5.0	2.2	1.7
SASK.	4.0	3.8	6.0	5.1	1.6	1.3	1.6	0.7	5.7	5.1	5.2	4.2	3.39	2.54	-1.0	1.5	4.8	4.5	2.2	1.3
ALTA.	3.8	4.1	11.0	4.0	2.4	2.0	2.4	2.0	5.3	5.3	5.0	4.0	37.02	32.21	-2.0	4.3	4.9	5.1	4.0	1.8
B.C.	1.5	2.9	4.2	3.4	2.2	1.1	2.2	0.9	8.5	8.4	2.0	4.1	23.55	22.73	2.0	5.0	2.2	4.8	2.1	1.5
CANADA	**2.1**	**3.5**	**5.4**	**4.2**	**2.0**	**1.3**	**2.1**	**1.3**	**7.7**	**7.7**	**3.5**	**4.4**	**208.25**	**183.00**	**0.6**	**4.6**	**5.0**	**4.6**	**2.8**	**1.5**

Key provincial comparisons

2002 unless otherwise indicated

	Nfld.	P.E.I.	N.S.	N.B.	Que.	Ont.	Man.	Sask.	Alta.	B.C.
Population (000s)	532	140	944	756	7,450	12,038	1,150	1,012	3,107	4,136
Gross domestic product ($ billions, 2002)	16.0	3.8	26.2	20.9	242.9	470.6	36.5	34.5	150.5	134.4
Real GDP ($1997, billions)	14.3	3.3	24.1	19.6	227.3	447.1	33.6	30.4	125.0	126.1
Share of Canada real GDP (%)	1.3	0.3	2.2	1.8	21.2	41.6	3.1	2.8	11.6	11.7
Real GDP growth (CAR, last five years, %)	6.3	3.6	3.4	3.1	3.8	4.5	2.5	0.8	3.2	2.0
Real GDP per capita ($)	26,871	23,951	25,527	25,914	30,506	37,144	29,264	30,006	40,248	30,498
Real GDP growth rate per capita (CAR, last five years, %)	7.2	3.2	3.2	3.0	3.4	3.0	2.2	1.0	1.2	1.0
Personal disposable income per capita ($)	17,915	19,022	19,851	19,529	20,644	23,748	20,909	18,484	24,892	21,124
Employment growth (CAR, last five years, %)	2.5	2.5	2.2	2.2	2.4	2.7	1.5	0.5	2.8	1.1
Employment rate (August 2003, %)	53.9	67.5	59.1	59.1	60.9	64.5	66.6	66.1	70.7	61.1
Discomfort index (inflation + unemp. rates)	19.3	15.9	12.7	13.8	10.6	9.1	6.8	8.5	8.7	10.8
Manufacturing industry output as a % of real GDP, 2002	5.7	10.2	10.4	14.8	21.7	20.4	12.6	7.3	9.3	10.5
Personal expenditures goods & servies, % of real GDP, 2002	60.2	67.7	68.4	63.6	57.6	53.6	61.0	57.3	51.2	64.4
International exports (% of real GDP, 2002)	36.3	28.9	28.1	39.6	37.8	49.8	30.2	39.7	35.3	30.1

Source: Statistics Canada, RBC Financial Group Economics Department

PROVINCIAL REAL GDP
Per cent change

	2000	2001	2002	Forecast 2003	2004
CANADA	4.5	1.5	3.4	2.0	2.8
N. & L.	5.9	1.3	13.4	4.8	1.8
P.E.I.	3.9	0.0	5.6	1.8	2.9
N.S.	1.8	2.5	3.8	2.2	3.1
N.B.	1.4	1.0	3.3	2.0	2.5
Quebec	4.7	1.1	4.3	1.9	2.4
Ontario	4.6	1.5	3.9	1.8	2.9
Manitoba	2.5	1.4	2.4	2.2	2.8
Sask.	2.8	-1.3	-1.4	4.5	3.5
Alberta	5.7	2.3	1.7	3.0	3.7
B.C.	4.3	-0.2	1.8	1.7	2.8

e (estimate) and forecast by TD Economics as at July 2003
Real GDP: Real gross domestic product
Source: Statistics Canada, TD Economics

PROVINCIAL REAL PERSONAL DISPOSABLE INCOME (PDI)
Annual average per cent change

	2000	2001	2002	Forecast 2003	2004
CANADA	4.6	2.6	2.5	1.8	3.3
N. & L.	2.4	2.7	3.0	1.7	2.8
P.E.I.	2.4	1.8	4.7	1.5	3.3
N.S.	2.2	1.9	0.5	1.8	3.5
N.B.	1.6	2.5	1.0	0.8	3.2
Quebec	4.2	3.3	3.5	1.5	2.9
Ontario	5.5	1.3	3.0	2.0	3.4
Manitoba	3.2	1.6	1.8	1.0	3.2
Sask.	1.0	1.1	-2.6	1.4	3.5
Alberta	6.6	6.7	3.0	2.7	4.3
B.C.	3.7	2.1	0.8	1.8	3.3

forecast by TD Economics as at July 2003
Source: Statistics Canada, TD Economics

EMPLOYMENT
Annual average per cent change

	2000	2001	2002	Forecast 2003	2004
CANADA	2.6	1.1	2.2	2.1	1.6
N. & L.	-0.1	3.3	1.2	2.0	1.2
P.E.I.	5.2	2.2	1.8	1.7	1.6
N.S.	2.7	0.9	1.2	2.1	1.4
N.B.	1.8	0.0	3.3	0.9	1.5
Quebec	2.4	1.1	3.4	1.8	1.2
Ontario	3.2	1.5	1.8	2.3	1.5
Manitoba	2.2	0.6	1.6	1.0	1.5
Sask.	1.0	-2.6	2.0	1.8	1.8
Alberta	2.2	2.8	2.6	2.8	2.5
B.C.	2.2	-0.3	1.6	2.0	1.7

Forecast by TD Economics as at July 2003
Source: Statistics Canada, TD Economics

UNEMPLOYMENT RATE
Per cent

	2000	2001	2002	Forecast 2003	2004
CANADA	6.8	7.2	7.7	7.6	7.3
N. & L.	16.7	16.1	16.9	16.9	16.6
P.E.I.	12.0	11.8	12.1	11.5	11.2
N.S.	9.1	9.7	9.7	9.0	8.8
N.B.	10.0	11.2	10.4	10.4	10.0
Quebec	8.4	8.7	8.6	8.8	8.6
Ontario	5.7	6.3	7.1	6.9	6.6
Manitoba	4.9	5.0	5.2	4.7	4.7
Sask.	5.2	5.8	5.7	5.5	5.0
Alberta	5.0	4.6	5.3	5.3	4.9
B.C.	7.2	7.7	8.5	8.3	8.1

Forecast by TD Economics as at July 2003
Source: Statistics Canada, TD Economics

CONSUMER PRICE INDEX
Annual average per cent change

	2000	2001	2002	Forecast 2003	2004
CANADA	2.7	2.6	2.2	2.6	1.6
N. & L.	3.0	1.1	2.4	2.8	1.4
P.E.I.	4.1	2.6	2.7	3.2	1.3
N.S.	3.5	1.8	3.0	3.2	1.5
N.B.	3.3	1.7	3.4	3.3	1.2
Quebec	2.4	2.4	2.0	2.6	1.5
Ontario	2.9	3.1	2.0	2.5	1.6
Manitoba	2.5	2.6	1.6	2.2	1.5
Sask.	2.6	3.1	2.8	2.4	1.7
Alberta	3.5	2.3	3.4	3.9	2.0
B.C.	1.9	1.7	2.3	2.2	1.5

Forecast by TD Economics as at July 2003
Source: Statistics Canada, TD Economics

HOUSING STARTS
Thousands of units

	2000	2001	2002	Forecast 2003	2004
CANADA	151.7	162.7	205.0	200.0	190.0
N. & L.	1.5	1.8	2.4	2.0	1.9
P.E.I.	0.7	0.7	0.8	0.6	0.6
N.S.	4.4	4.1	5.0	4.5	4.2
N.B.	3.1	3.5	3.9	4.5	4.0
Quebec	24.7	27.7	42.5	43.0	39.0
Ontario	71.5	73.3	83.6	77.0	73.2
Manitoba	2.6	3.0	3.6	3.8	3.6
Sask.	2.5	2.4	3.0	3.6	3.5
Alberta	26.3	29.2	38.8	37.0	36.0
B.C.	14.4	17.2	21.6	24.0	24.0

Forecast by TD Economics as at July 2003
Source: Canada Mortgage and Housing Corporation, TD Economics

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2004 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-3 INDEX

2004 Rate Base

The 2004 Rate base is forecast to be $2.3 billion. Rate Base is composed of mid-year net gas plant in service, construction advances, work in progress not attracting AFUDC, unamortized deferred charges, cash working capital, other working capital, deferred income tax, and LILO benefit.

The 2004 Rate Base includes full year impacts of the 2003 projected plant activities including:

- 2003 CPCN Opening Additions of $27.0 million
- Base Capital Additions of $117.7 million
- Plant Depreciation of $79.7 million
- Contribution in Aid of Construction Amortization of $8.1 million.

Details of the 2003 projected plant balances can be found in Section A, Tab 8.

Also, the 2004 Rate Base includes 2004 activities including:

- 2004 CPCN Opening Additions of $10.1 million (Section A, Tab 3, Page 5, Line 42) - full year impact
- Base Capital Additions of $112.9 million (Section A, Tab 3, Page 5, Line 33) - mid-year impact
- Depreciation and Amortization of $78.9 million (Section A, Tab 1, Page 6) - mid-year impact
- Various changes in deferred charges, working capital and other items reducing rate base by a net amount of $5.5 million.

2004 Capital Expenditures

The 2004 Capital Expenditures are based on the capital expenditure formula (approved by BCUC Order No. G-51-03) plus forecast CPCNs. The capital expenditure formula is composed of two cost components: Customer Addition Driven Capital and Other Base Capital.

The 2004 unit cost formula is computed as:

- 2004 Forecast Unit Cost per Customer =
  - PBR Settlement Unit Cost x ([1 + (CPI - Adjustment Factor)]
  - The 2004 Forecast CPI is 1.7%
  - The Adjustment Factor for 2004 is computed as 50% of CPI
  - The 2004 Adjustment Factor is 0.85% (50% x 1.7% CPI)

The 2004 Capital Expenditure is calculated using the 2004 Forecast Unit Cost. It is computed as:

- 2004 Capital Expenditure =
  - 2004 Forecast Unit Cost per customer x Cost Driver
  - The Cost Driver for:
    - Customer Addition Driven Capital is Number of Customer Additions
    - Other Base Capital is Average Number of Customers

<u>Calculation of 2004 Capital Expenditures</u>

1. Customer Addition Driven Capital Expenditures
   - $2,093.04 x (1 + 1.7% - (50% of 1.7%)) = $2,110.83 per customer addition
   - $2,110.83 x 8,604 customer additions = $18.162 million
2. Other Base Capital Expenditures
   - $85.69 x (1 + 1.7% - (50% of 1.7%)) = $86.42 per customer
   - $86.42 x 777,779 average customers = $67.216 million
3. Special Projects - CPCN Capital Expenditures
   - Transmission Pipeline Integrity Plan (BCUC Orders C-15-01, C-3-02, and C-4-03)
     - Total 2004 TPIP Expenditures: $2.777 million (Section A, Tab 3, Page 5, Line 14)

2004 Plant Additions

The 2004 Plant Additions are comprised of the 2004 Base Capital plant costs including AFUDC that are put in-service during the year, overhead capitalized for the year, and opening 2004 CPCN Additions. The opening 2004 CPCN plant additions are the CPCN plant costs put in-service in 2003. The reconciliation of capital expenditures to plant additions is shown on Section A, Tab 3, Page 5.

The 2004 Plant Additions allowed by the terms of the Settlement is $123.031 million. The Plant Addition summary is shown below:

2004 Plant Additions	
Formula-based Based Capital	$ 86.905 million
Overhead Capitalized	$ 26.009 million
Opening CPCN Additions	$ 10.117 million
Total 2004 Plant Additions	$ 123.031 million

Consistent with the terms of the Settlement, the 2004 Contributions in Aid of Construction Additions (“CIAOC”) are formula-based. The software tax savings are based on the software plant additions arising from the base capital additions formula. The Service Line Installation Fee is calculated based on $215 per service line. The other CIAOC consisting of main extensions, excess service line charges, billable alterations, meter & regulator equipment work, and other CIAOC have been calculated based on the PBR Formula. In addition to the formula based calculation the total CIAOC forecast includes $1.1 million transferred from Construction Advances to CIAOC. The CIAOC schedule can be found in Section A, Tab 3, Page 8.

TERASEN GAS INC.
CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2004

Line. No.	Particulars	PBR Settlement 2003	Forecast 2004
	(1)	(2)	(3)
1	Forecast CPI (BC)		1.70%
2	Adjustment Factor		0.85%
3			
4	CPI - Adjustment Factor		100.85%
5			
6			
7	**CUSTOMER ADDITION DRIVEN CAPITAL EXPENDITURES**		
8			
9	Customer Addition Driven Capital Expenditure Per Customer Addition	$2,093.04	$2,110.83
10			
11	Number of Customers Additions		8,604
12			
13	**Target Customer Addition Driven Capital Expenditures ($000)**		**$18,162**
14			
15			
16	**OTHER BASE CAPITAL EXPENDITURES**		
17			
18	Other Base Capital Expenditure Per Customer	$85.69	$86.42
19			
20	Average Number of Customers		777,779
21			
22	**Target Other Base Capital Expenditures ($000)**		**$67,216**
23			
24			
25			
26	**SUMMARY CAPITAL EXPENDITURES ($000)**		
27			
28	Target Customer Addition Driven Capital Expenditures		$18,162
29	Target Other Base Capital Expenditures		67,216
30			
31	Total Target Base Capital Expenditures		$85,378
32			
33			
34	**Total Base Capital Additions excluding Forecast CPCN Additions ($000)**		**$85,378**

TERASEN GAS INC.
CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2003 - 2004
($000)

Line No.	Particulars	Projected 2003	Forecast 2004
	(1)	(2)	(3)
1	**CAPITAL EXPENDITURES**		
2			
3	Base Capital Expenditures		
4	Customer Addition Driven Capital Expenditures		$18,162
5	Other Base Capital Expenditures		67,216
6			
7	Total Base Capital Expenditures	$85,511	$85,378
8			
9	Special Projects - CPCNs		
10	Transmission Pipeline Integrity Plan (BCUC Order No. C15-01)	$280	$0
11	Transmission Pipeline Integrity Plan (BCUC Order No. C-3-02)	1,420	2,777
12	Transmission Pipeline Integrity Plan (BCUC Order No. C-4-03)	8,871	0
13			
14	Total CPCNs	$10,571	$2,777
15			
16			
17	TOTAL CAPITAL EXPENDITURES	$96,082	$88,155
18			
19			
20			
21			
22	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**		
23			
24	Base Capital		
25	Base Capital Expenditures	$85,511	$85,378
26	Add - Opening WIP	17,898	11,891
27	Less - Opening WIP adjustment	(14)	0
28	Less - Closing WIP	(11,891)	(11,251)
29			
30	Add - AFUDC	965	887
31	Add - Overhead Capitalized	25,207	26,009
32			
33	TOTAL BASE CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$117,676	$112,914
34			
35	Special Projects - CPCNs		
36	CPCNs Expenditures	$10,571	$2,777
37	Add - Opening WIP	27,023	10,912
38	Less - Closing WIP	(10,912)	(3,671)
39			
40	Add - AFUDC	341	99
41			
42	TOTAL CPCN ADDITIONS TO OPENING GAS PLANT IN SERVICE	$27,023	$10,117
43			
44			
45	TOTAL PLANT ADDITIONS	$144,699	$123,031

TERASEN GAS INC.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004 Existing Rates	2004 Adjustments	2004 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$2,711,233	$2,816,944	$0	$2,816,944	$105,711	- Tab 3, Page 7.1
2	CPCNs	31,845	10,117	0	10,117	(21,728)	- Tab 3, Page 7.1
3							
4	Additions	115,430	112,914	0	112,914	(2,516)	- Tab 3, Page 7.1
5	Disposals	(13,067)	(21,139)	0	(21,139)	(8,072)	- Tab 3, Page 7.1
6							
7	Plant in Service, Ending	2,845,441	2,918,836	0	2,918,836	73,395	
8							
9	Add - Intangible Plant	837	837	0	837	0	
10							
11		2,846,278	2,919,673	0	2,919,673	73,395	
12							
13	Contributions In Aid of Construction	(147,888)	(149,325)	0	(149,325)	(1,437)	- Tab 3, Page 8
14							
15	Less - Accumulated Depreciation	(527,002)	(566,585)	0	(566,585)	(39,583)	- Tab 3, Page 13
16							
17							
18	Net Plant in Service, Ending	$2,171,388	$2,203,763	$0	$2,203,763	$32,375	
19							
20							
21	Net Plant in Service, Beginning	$2,138,353	$2,177,251	$0	$2,177,251	$38,898	- Tab 3, Page 9
22							
23							
24	Net Plant in Service, Mid-Year	$2,154,871	$2,190,507	$0	$2,190,507	$35,636	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(1,000)	(750)	0	(750)	250	
27	Work in Progress, No AFUDC	4,000	4,000	0	4,000	0	
28	Unamortized Deferred Charges	31,076	25,610	0	25,610	(5,466)	- Tab 3, Page 11.1
29	Cash Working Capital	(13,061)	(19,104)	305	(18,799)	(5,738)	- Tab 3, Page 12
30	Other Working Capital	98,485	101,177	0	101,177	2,692	- Tab 3, Page 12
31	Deferred Income Tax, Mid-Year	(364)	(364)	0	(364)	0	
32	Capital Efficiency Mechanism	(1,381)	0	0	0	1,381	
33	LILO Benefit	(2,265)	(1,510)	0	(1,510)	755	
34	Utility Rate Base	$2,270,361	$2,299,566	$305	$2,299,871	$29,510	

GAS PLANT IN SERVICE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Projected Balance 12/31/2003	CPCN'S	2004 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	401 Franchise Consents	99	$0	$0	$0	$0	$99
2	402 Other Intangible Plant	770	0	0	0	0	$770
3	TOTAL INTANGIBLE PLANT	869	0	0	0	0	869
4							
5	430 Manufact'd Gas - Land	31	0	0	0	0	31
6	432 Manufact'd Gas - Struct. & Improvements	436	0	0	0	0	436
7	433 Manufacturing Equipment	139	0	0	0	0	139
8	434 Gas Holders - Manufacturing	358	0	0	0	0	358
9	436 Compressed Equipment	53	0	0	0	0	53
10	437 Measuring and Regulating Equipment	299	0	0	0	0	299
11	440/441 Land in Fee Simple and Land Rights	927	0	0	0	0	927
12	442 Structures and Improvements	4,885	0	0	0	0	4,885
13	443 Gas Holders - Storage	16,519	0	399	0	0	16,918
14	446 Compressor Equipment	0	0	0	0	0	0
15	447 Measuring and Regulating Equipment	0	0	0	0	0	0
16	448 Purification Equipment	0	0	0	0	0	0
17	449 Local Storage Equipment	16,737	0	0	0	0	16,737
18	**TOTAL MANUFACTURED GAS / LOCAL STORAGE**	40,384	0	399	0	0	40,783
19							
20	460 Land in Fee Simple	7,790	0	0	0	0	7,790
21	461 Land Rights	37,506	0	1,994	0	0	39,500
22	462 Compressor Structures	14,350	0	399	0	0	14,749
23	463 Measuring Structures	4,275	0	0	0	0	4,275
24	464 Other Structures and Improvements	4,897	0	0	0	0	4,897
25	465 Mains	689,342	10,117	4,080	(631)	0	702,908
26	466 Compressor Equipment	103,899	0	202	0	0	104,101
27	467 Measuring and Regulating Equipment	34,541	0	5,294	0	0	39,835
28	468 Communication Structures and Equipment	847	0	680	0	0	1,527
29	469 Other Transmission Equipment	0	0	0	0	0	0
30	**TOTAL TRANSMISSION PLANT**	897,447	10,117	12,649	(631)	0	919,582
31							
32	470 Land	3,150	0	0	0	0	3,150
33	471 Land Rights	669	0	0	0	0	669
34	472 Structures and Improvements	6,491	0	365	0	0	6,856
35	473 Services	520,851	0	18,076	(1,956)	0	536,971
36	474 House Regulators and Meter Installations	138,357	0	9,017	(322)	0	147,052
37	475 Mains	707,289	0	29,073	(1,840)	0	734,522
38	476 Compressor Equipment						0
39							0
40	-All Other	575	0	0	0	0	575
41	477 Measuring and Regulating Equipment	61,040	0	9,546	(315)	0	70,271
42	478 Meters	171,308	0	14,537	(532)	0	185,313
43	479 Other Distribution Equipment	0	0	0	0	0	0
44	**TOTAL DISTRIBUTION PLANT**	1,609,730	0	80,614	(4,965)	0	1,685,379

TERASEN GAS INC.

GAS PLANT IN SERVICE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Projected Balance 12/31/2003	CPCN'S	2004 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	480 Land	20,890	$0	$20	$0	$0	$20,910
2	481 Land Rights	0	0	0	0	0	0
3	482 Structures and Improvements						
4	- Coastal Facilities						0
5	-All Other	30,503	0	617	0	0	31,120
6	483 Office Furniture and Equipment	0					
7	- Furniture and Equipment	23,326	0	464	(20)	0	23,770
8	-Computers - Hardware	27,058	0	5,991	(6,459)	0	26,590
9	-Computer Software - Non-Infrastructure	40,578	0	1,471	(1,871)	0	40,178
10	-Computer Software - Infrastructure/Custom	84,823	0	7,820	(5,734)	0	86,909
11							
12							
13	484 Transportation Equipment	747	0	42	(261)	0	528
14							
15	485 Heavy Work Equipment	265	0	0	(4)	0	261
16	486 Tools and Work Equipment	23,797	0	1,911	(217)	0	25,491
17	487 Equipment on Customer's Premises	1,813	0	0	0	0	1,813
18	488 Communication Equipment	14,712	0	916	(977)	0	14,651
19	489 Other General Equipment						
20	-Stores Material, Capital	0	0	0	0	0	0
21	-All Other	2	0	0	0	0	2
22							
23	**TOTAL GENERAL EQUIPMENT**	268,514	0	19,252	(15,543)	0	272,223
24							
25	492 Gas Plant Held for Future Use	0	0	0	0	0	0
26	496 Unclassified Plant	0	0	0	0	0	0
27	497 Allowance for Funds Used						
28	During Construction	0	0	0	0	0	0
29	498 Overhead Charged To Construction	0	0	0	0	0	0
30	499 Plant Suspense	0	0	0	0	0	0
31							
32	**TOTAL UNCLASSIFIED PLANT**	0	0	0	0	0	0
33							
34	**TOTAL CAPITAL**	$2,816,944	$10,117	$112,914	($21,139)	$0	$2,918,836

TERASEN GAS INC..

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars		Projected Balance 12/31/2003	2004 Additions	2004 Retirements	Balance 12/31/2004
	(1)		(2)	(3)	(4)	(5)
1	DSEP/GEAP	211-06	12,671	$0	$0	$12,671
2						
3	NGV Conversion Grants	211-07	0	0	0	0
4						
5	NGV Station Grants	211-08	0	0	0	0
6						
7	Furniture & Equipment	211-10	111	0	0	111
8						
9	Software Tax Savings - Non-Infrastructure	211-11	14,246	528	(1,956)	12,818
10	- Infrastructure/Custom	211-11	40,093	2,850	(224)	42,719
11	Service Installation Fee	211-12	16,104	1,850	0	17,954
12						
13	Other	211-00 to 05	59,441	3,611	0	63,052
14	(Main Extensions, Excess Service Line Charges, etc.)					
15	TOTAL		142,666	8,839	(2,180)	149,325
16						
17						
18						
19	Amortization	211-15 to 22				
20						
21	- Software Tax Savings - Non-Infrastructure		(5,925)	(2,849)	1,956	(6,818)
22	- Infrastructure/Custom		(16,253)	(5,012)	224	(21,041)
23	- Other		(17,738)	(1,946)	0	(19,684)
24						
25						
26	Total Amortization		(39,916)	(9,807)	2,180	(47,543)
27						
28	NET		102,750	($968)	$0	$101,782

TERASEN GAS INC.

NET GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2004
($000)

Line No.	Particulars	Projected 2003 Amount	Forecast 2004 Amount	Reference
	(1)	(2)	(3)	(4)
1	Gas Plant in Service - December 31, Previous Year	$2,696,795	$2,816,944	
2				
3	Add: CPCNs on January 1, Beginning of the Year	27,023	10,117	
4				
5	Adjusted Opening Gas Plant in Service	2,723,818	2,827,061	
6				
7	Intangible Plant	837	837	- Tab 1, Page 5
8				
9	Less: Contribution in Aid of Construction	(134,289)	(142,666)	- Tab 3, Page 8
10				
11	Less: Accumulated Depreciation and Amortization	(459,971)	(507,981)	- Tab 3, Page 13
12				
13	Net Gas Plant in Service as at January 1,	$2,130,395	$2,177,251	- Tab 1, Page 5

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
DEFERRED CHARGES
FOR THE YEAR ENDING DECEMBER 31, 2004

The 2004 deferred charges and amortization (Section A, Tab 3, Pages 11 and 11.1) have been determined in accordance with the BCUC Decision dated February 4, 2003 on Terasen Gas' 2003 revenue requirements and the 2004-2007 PBR Plan Settlement Terms approved by BCUC Order No. G-51-03.

The projected GCRA net-of-tax balance is currently estimated to be nil by December 31, 2003. This means that income tax benefits built up over the period of declining income tax rates have been returned to customers by the end of 2003 in accordance with BCUC Order No. G-34-03.

The large accumulation in 2003 in the RSAM account is due to a combination of lower use rates than those approved in the 2003 Decision and warmer than normal weather. The amortization period continues to be 3 years.

Future disposition of GCRA and RSAM balances will be determined based on the net-of-tax balance in accordance with BCUC Order No. G-34-03.

Deferred interest has been adjusted in 2003 to a net-of-tax basis, consistent with the intent of BCUC Orders No. G-34-03 and G-53-94.

The schedule of 2003 projected deferred charges and amortization is found in Section A, Tab 8, Pages 4 and 4.1

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Account	Projected Balance 12/31/2003	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2004	Mid-Year Average 2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($3,716)	$0	0	$0	$1,428	$0	($2,288)	($3,002)
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	8	0	0	0	(8)	0	0	4
5										
6	NGV Conversion Grants	#17977	245	295	(102)	193	(59)	0	379	311
7										
8	2003 Revenue Requirement	#17989	272	0	0	0	(65)	0	207	240
9	2004-2007 Revenue Requirements	#17952	159	30	(10)	20	(32)	0	147	153
10										
11	Demand Side Management	#17916	2,006	1,500	(518)	982	(898)	0	2,090	2,048
12	DSM DRIA	#17961	(175)	0	0	0	87	0	(88)	(132)
13										
14	Property Tax Deferral	#17915	(1,514)	0	0	0	540	0	(974)	(1,244)
15										
16	G.C.R.A.	#17926	0	0	0	0	0	0	0	0
17	G.C.R.A. Interest	#17973	(417)	0	0	0	0	417	0	(209)
18										
19	RSAM	#17927	44,691	0	0	0	0	(14,897)	29,794	37,243
20	RSAM Interest	#17999	229	0	0	0	0	(76)	153	191
21										
22	Revelstoke Propane Cost	#27902	(105)	160	(55)	105	0	0	0	(53)
23										
24	B.C. Hydro Service Agreement Costs	#17963	471	0	0	0	(471)	0	0	236
25										
26	Coastal Facilities									
27	- Relocation	#17951	682	0	0	0	(341)	0	341	512
28	- Extraordinary Plant Loss - Lochburn	#17998	93	0	0	0	(22)	0	71	82
29	- Fraser Valley NBV Amortization	#17996	419	0	0	0	(213)	0	206	313
30	- Noncapital Finance Costs	#17984	368	0	0	0	(368)	0	0	184

TERASEN GAS INC..

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Account	Projected Balance 12/31/2003	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2004	Mid-Year Average 2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
31	ABC T Project Requirements Phase	#17918	30	0	0	0	(30)	0	0	15
32										
33	Burner Tip Service	#17972	(5)	0	0	0	5	0	0	(3)
34										
35	Earnings Sharing Mechanism	#17982	0	0	0	0	0	0	0	0
36										
37	Salmon Arm Reinforcement	#17990	0	0	0	0	0	0	0	0
38										
39	NGV Compression Equip. Recovery	#17992	1,278	0	0	0	(213)	0	1,065	1,172
40										
41	2001 Rate Design	#17974	115	0	0	0	(115)	0	0	58
42										
43	Overheads Change - Income Tax Refund	#17995	(554)	0	0	0	138	0	(416)	(485)
44	CIAOC Software Tax Savings/OH Change	#17995	(3,231)	0	0	0	808	0	(2,423)	(2,827)
45										
46	Other Post Employment Benefits	#17991/93	(8,561)	(5,717)	1,972	(3,745)	0	0	(12,306)	(10,434)
47										
48	Deferred 2000 SCP Cost of Service	#17997	254	0	0	0	(64)	0	190	222
49										
50	SCP Net Mitigation Revenues	#17912	(2,504)	639	(220)	419	655	0	(1,430)	(1,967)
51	SCP West to East Transmission	#17913	1,442	0	0	0	(359)	0	1,083	1,263
52	SCP PG&E Contract Cancellation	#17936	889	3,000	(1,035)	1,965	0	0	2,854	1,872
53										
54										
55	CCT Deferral	#17924	(531)	0	0	0	133	0	(398)	(465)
56	CCT Assessment	#17929	374	0	0	0	(125)	0	249	312
57										
58										
59	Total Deferred Charges for Rate Base		$32,712	($93)	$32	($61)	$411	($14,556)	$18,506	$25,610

TERASEN GAS INC..

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004 Existing Rates	2004 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	($7,591)	($11,816)	($11,511)	(3,920)	Note 1
4						
5	Minimum Cash Balances/					
6	Customer Deposits	(2,478)	(3,813)	(3,813)	(1,335)	Note 2
7						
8	Less - Funds Available:					
9						
10	Reserve for Bad Debts	(374)	(775)	(775)	(401)	
11						
12	Withholdings From					
13	Employees	(2,618)	(2,700)	(2,700)	(82)	
14						
15	Subtotal	(13,061)	(19,104)	(18,799)	(5,738)	- Tab 1, Page 5
16						
17	**Other Working Capital Items**					
18	Inventories	4,764	4,054	4,054	(710)	
19	Transmission Line Pack Gas	1,825	2,993	2,993	1,168	
20	Gas in Storage	91,896	94,130	94,130	2,234	- Tab 3, Page 12.2
21						
22						
23	Subtotal	98,485	101,177	101,177	2,692	- Tab 1, Page 5
24						
25	Total	$85,424	$82,073	$82,378	($3,046)	

Explanatory Notes for Working Capital Allowance

Note 1: The larger credit to rate base for Cash Required for Operating Expense is due primarily to the increase in the gas costs passed through in rates.

Note 2: The increase of Minimum Cash Balances/Customers Deposits is due primarily to the higher security deposits from customers from 2003 credit management activity.

TERASEN GAS INC.

GAS INVENTORY - 13 MONTHS AVERAGES
FOR THE YEAR ENDING DECEMBER 31, 2004

Line No.	Particulars	TJ	$/GJ	$(000)	TJ	$/GJ	$(000)	TJ	$/GJ	$(000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**13 Months Averages**									
2		**Decision (2003)**			**October 2003 Forecast (2004)**			**Difference (2004 - 2003)**		
3										
4	Aitken Creek	11,592.2	$ 4.9375	$ 57,237.0	12,774.4	$ 5.2346	$ 66,869.5	1,182.2	$ 0.2971	$ 9,632.5
5	Carbon (Alberta) Storage	1,880.1	$ 4.8843	9,182.9	1,566.6	$ 5.1453	8,060.6	(313.5)	$ 0.2610	(1,122.3)
6	Clay Basin	-	$ -	-	-	$ -	-	-	$ -	-
7	Jackson Prairie	2,314.0	$ 5.4471	12,604.5	1,883.0	$ 5.7815	10,886.6	(431.0)	$ 0.3344	(1,717.9)
8	LNG	483.8	$ 4.8295	2,336.5	345.3	$ 5.1019	1,761.7	(138.5)	$ 0.2724	(574.8)
9	Mist	714.1	$ 5.5739	3,980.3	1,128.7	$ 5.8048	6,551.9	414.6	$ 0.2309	2,571.6
10	SoCal	1,133.9	$ 5.7809	6,555.0	-	$ -	-	(1,133.9)	$ -	(6,555.0)
11	New Storage	-	$ -	-	-	$ -	-	-	$ -	-
12	Total Gas in Storage	18,118.1	$ 5.0721	$ 91,896.2	17,698.0	$ 5.3187	$ 94,130.3	(420.1)	$ 0.2466	$ 2,234.1

TERASEN GAS INC..

ACCUMULATED DEPRECIATION
FOR THE YEARS ENDING DECEMBER 31, 2003 - 2004
($000)

Line No.	Particulars	Projected 2003	Forecast 2004	Reference
	(1)	(2)	(3)	(4)
1	Balance, Beginning	$492,735	$547,897	- Tab 3, Page 13.3
2				
3	CIAOC Amortization Balance, Beginning	(32,764)	(39,916)	- Tab 3, Page 8
4				
5	Gas Plant Held for Future Use			
6	Balance, Beginning	0	0	
7				
8	Retirement Work in Progress	0	0	
9				
10	Utility Accumulated Depreciation			
11	Balance, Beginning	459,971	507,981	- Tab 3, Page 9
12				
13	Depreciation Provision			
14	Total Plant	79,713	89,103	- Tab 3, Page 13.3
15	Less - Gas Plant Held for Future Use	0	0	
16	Less Prior Year Adjustments			
17	Less - Amortization of Contributions in			
18	Aid of Construction	(8,147)	(9,807)	- Tab 3, Page 8
19				
20		71,566	79,296	
21				
22	Plant Retirements	(24,551)	(21,139)	- Tab 3, Page 13.3
23				
24	CIAOC Retirements	995	2,180	- Tab 3, Page 8
25				
26	Removal Costs	0	(1,859)	- Tab 3, Page 13.3
27				
28	Proceeds on Disposals	0	126	- Tab 3, Page 13.3
29				
30		(23,556)	(20,692)	
31				
32	Balance, Ending	$507,981	$566,585	- Tab 1, Page 5

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Account	Balance 12/31/2003	Annual Depreciation Rate %	Provision 2004 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2003	Accumulated 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	45	46
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	326	333
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	44	45
6	402-00 Utility Plant Acquisition Adjustment	685	1.00%	7	0	0	0	0	31	38
7	402-00 Other Intangible Plant - Lease	85	Lease Term	1	0	0	0	0	90	91
8		1,706		17	0	0	0	0	536	553
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	102-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	102-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	102-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	432 Manufact'd Gas - Struct. & Improvements									
22	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
23	- Masonry Buildings	436	1.50%	7	0	0	0	0	63	70
24	433 Manufacturing Equipment	139	3.00%	4	0	0	0	0	26	30
25	434 Gas Holders - Manufacturing	358	2.00%	7	0	0	0	0	130	137
26	436 Compressor Equipment	53	3.00%	1	0	0	0	0	13	14
27	437 Measuring & Regulating	299	3.00%	9	0	0	0	0	96	105
28	442-00 Structures and Improvements	4,885	4.00%	195	0	0	0	0	1,214	1,409
29	443-00 Gas Holders Storage	16,519	4.00%	661	0	0	0	0	6,031	6,692
30	449-00 Local Storage Equipment	16,737	4.00%	669	0	0	0	0	5,835	6,504
31		39,426		1,553	0	0	0	0	13,408	14,961

TERASEN GAS INC..

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Account	Balance 12/31/2003	Annual Depreciation Rate %	Provision 2004 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2003	Accumulated 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461 Land Rights - Byron Creek	$16	5.00%	$1	$0	$0	$0	$0	$14	$15
3	460-00 / 461-00 Land / Land Rights	45,280	0.00%	0	0	0	0	0	232	232
4	462-00 Structures and Improvements - Compressor Stn	14,350	3.00%	431	0	0	0	0	2,642	3,073
5	463-00 Measuring & Regulating	4,275	3.00%	128	0	0	0	0	684	812
6	464-00 Other Structures - Frame Buildings	4,897	3.00%	147	0	0	0	0	365	512
7	465-00 Mains & Crossings	698,574	2.00%	13,971	0	(631)	(79)	0	107,508	120,769
8	465-00 Mains & Crossings - Byron Creek	885	5.00%	44	0	0	0	0	609	653
9	466-00 Compressor Equipment	103,899	3.00%	3,117	0	0	0	0	16,267	19,384
10	467-00 Measuring & Regulating	28,744	3.00%	862	0	0	0	0	4,097	4,959
11	467-10 Telemetering	5,797	10.00%	580	0	0	0	0	3,931	4,511
12	468-00 Communications Structures & Equip.	847	10.00%	85	0	0	0	0	285	370
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		907,564		19,366	0	(631)	(79)	0	136,634	155,290
15										
16	**DISTRIBUTION PLANT**									
17	471 Land Rights - Byron Creek	1	0.00%	0	0	0	0	0	4	4
18	472-00 Structures & Improvements									
19	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
20	-Frame Buildings	6,489	3.00%	195	0	0	0	0	1,402	1,597
21	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
22	-Byron Creek	2	3.00%	0	0	0	0	0	2	2
23	473-00 Services	520,851	2.00%	10,417	0	(1,956)	(1,376)	0	68,313	75,398
24	474-00 House Regulator & Meter Installation	138,357	3.57%	4,939	0	(322)	(188)	2	23,004	27,435
25	475-00 Mains	707,289	2.00%	14,146	0	(1,840)	(184)	0	151,842	163,964
26	476-00 Compressed Natural Gas									
27										
28	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
29	-All Other	575	6.67%	38	0	0	0	0	142	180
30	477-00 Measuring & Regulating	55,534	3.00%	1,666	0	(315)	(9)	0	5,151	6,493
31	477-10 Telemetering	5,311	10.00%	531	0	0	0	0	3,308	3,839
32	477-00 Measuring & Regulating - Byron Creek	195	5.00%	10	0	0	0	0	9	19
33	478 Meters	171,308	3.57%	6,116	0	(532)	(23)	124	28,263	33,948
34	479 Other Distribution Equipment	0	4.00%	0	0	0	0	0	0	0
35		1,605,912		38,058	0	(4,965)	(1,780)	126	281,440	312,879

TERASEN GAS INC..

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Account	Balance 12/31/2003	Annual Depreciation Rate %	Provision 2004 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2003	12/31/2004
		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	GENERAL PLANT									
1	480-00 Land	20,890	0%	$0	$0	$0	$0	$0	$0	$0
2	482-00 Structures & Improvements									
3	-Leasehold Alterations	$13,950	Term - Lease	$1,943	$0	$0	$0	$0	$659	$2,602
4	-Masonry Buildings	12,001	1.50%	180	0	0	0	0	2,048	2,228
5	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,538)	(3,401)
6	483-00 Office Furniture & Equipment									
7	-Furniture & Equipment	23,326	5.00%	1,166	0	(20)	0	0	8,282	9,428
8	-Computers - Hardware	27,058	20.00%	5,412	0	(6,459)	0	0	18,445	17,398
9										
10	-Computer Software - Non-Infrastructure	40,578	20.00%	8,116	0	(1,871)	0	0	17,810	24,055
11	-Computer Software - Infrastructure/Custom	84,823	12.50%	10,603	0	(5,734)	0	0	36,487	41,356
12										
13	484-00 Transportation Equipment	747	15.00%	112	0	(261)	0	0	2,658	2,509
14	485-00 Maintenance & Repair Equipment	265	5.00%	13	0	(4)	0	0	(356)	(347)
15	486-00 Tools & Work Equipment	23,797	5.00%	1,190	0	(217)	0	0	8,489	9,462
16	487-00 Equipment on Customers' Premises	1,230	5.00%	62	0	0	0	0	584	646
17	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
18	487-XX - VRA Compressor Installation Cost	583	33.33%	194	0	0	0	0	482	676
19	488-00 Communication - Structures & Equip.	9,799	5.00%	490	0	(977)	0	0	2,368	1,881
20	488-00 Communication - Radios	4,913	10.00%	491	0	0	0	0	2,842	3,333
21	489-00 Other General Equipment	2	5.00%	0	0	0	0	0	0	0
22		268,514		30,109	0	(15,543)	0	0	97,260	111,826
23										
24	**UNCLASSIFIED PLANT**									
25	498-00 O&M Expense Charged to Construction	0	2.27%	0	0	0	0	0	18,619	18,619
26										
27	TOTAL	$2,823,122		$89,103	$0	($21,139)	($1,859)	$126	$547,897	$614,128

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2004 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-4 INDEX

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
2004 GAS SALES AND TRANSPORTATION VOLUMES

This Section addresses the forecast of gas sales and transportation volumes for 2004. Included in this Section is a review of the energy-forecast methodology, as well as factors influencing customer additions and use per customer. An outline of the residential, commercial and industrial margins and revenues over the forecast period is also provided.

The yearly projections and forecasts provided in this Section are the best current estimates. Customer accounts and the use per account used to derive revenues for 2004 reflect the best information available at the time of the Annual Review.

The forecast of industrial accounts and associated volumes are updated to reflect the latest Industrial Survey conducted during the summer of 2003. Similarly, Revenue and margin forecasts reflect the most recently approved rates.

1. FORECAST METHODOLOGY

Under the 2004 – 2007 PBR Plan, new customer additions and the total customer base are the drivers of the operations, maintenance and capital costs allowed in the rate setting process. Forecasting these items establishes the variance between allowed costs and the revenues that would be collected by existing rates. Consistent with previous years, the forecasting process is separated into three main components:

- Customer additions forecast,
- Average Use per Residential and Commercial Account Forecast, and
- Industrial Forecast.

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

The customer additions forecast reflects the prevailing macroeconomic circumstances affecting residential and commercial customers. The forecast for industrial customers assumes no net change in the number of customers over the forecast period.

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

Up-to-date tariff schedules and rates are then applied against the energy forecast to calculate the revenue forecast. The underlying assumptions and components of that forecast are discussed below.

2. UNDERLYING ASSUMPTIONS

Terasen Gas expects recent conservation efforts and trends to persist.

Although the forecast assumes a modest recovery in most sectors of the regional economy, possible economic inhibitors such as the softwood lumber dispute are assumed unresolved before the end of 2003.   Further delay in resolving the dispute or a slide in the U.S. economy will likely reduce demand for key export commodities produced in British Columbia

Primary considerations of the energy forecast are summarised below.

- Natural gas commodity prices experience some price volatility.
- Regional economic recovery with slow growth for the balance of 2003 and 2004.
- Energy efficiency improves with appliance renewal and continuing conservation efforts.
- The competitive positioning of gas relative to electricity experiences some improvement.
- Key industrial and transportation sectors experience limited growth with improved energy efficiency.

3. CUSTOMER ADDITIONS FORECAST

The customer addition forecast is derived from broad regional economic forecasts and end-use information. Inputs gathered through industrial associations, research institutes, government agencies and periodic surveys provide the basis for relating economic data to account growth.

To forecast residential account additions, actual household formations and historical commodity price are statistically linked with actual account additions to model annual account growth on a service area basis. Household formation forecasts are then applied to obtain the expected number of additions adjusted for actual customer counts to date (August 2003). For the forecast produced in support of the 2003 Annual Review, the BC Statistics 2002 Household Formation Forecast is used to estimate household formations by area over the forecast period, with the near-term forecast validated by current housing start and service request information. Overall, estimates of additions for 2004 are consistent with those submitted in support of the PBR filing.

While the housing boom sparked by low mortgage rates in 2003 is adding new customer services at anticipated rates, total residential accounts are lower than expected. This is due to the higher than assumed number of service disconnections experienced to August 2003. Although reconnection rates[1] have been high, the larger volume of disconnections results in a downward adjustment in 2003 to the forecast of overall customer counts. It is believed that some of these disconnected accounts will not be reactivated, particularly as it relates to low-volume non-heating load.

The CMHC assumes low mortgage rates through 2003[2] which may lengthen the current housing boom into 2004. While these predictions may suggest optimism about long term growth in housing markets, Terasen Gas believes that gradually increasing mortgage rates, sluggish economic growth, and demographic shifts will limit customer additions.

New customer services will recover in the residential sector during 2003 and stabilize thereafter while the commercial sector will experience a slight decline. The small commercial market (Rate 2) has not shared in the recovery of large commercial and commercial transport demand (Rates 3 and 23 respectively). This may suggest that the drop[3] in commercial customers during the first 8 months of 2003 is a lagged response to economic retrenchment and high commodity prices. Small businesses are often unable to adjust their cost structures to changing economic circumstances and recovery in this sector tends to be slower in the

[1] An adjustment to the year end total customer additions for reduced reconnections is reported in the table immediately following Section 3.
[2] Housing Now (August, 2003): Canada Mortgage and Housing Corporation.
[3] This is based on a (consolidated) loss of 990 Rate 2 customers and a (consolidated) gain of 100 customers in Rates 3 and 23. Numbers quoted are approximate, and pertain to data as of August, 2003.

wake of economic downturns. But as economic conditions improve in 2004 and beyond, commercial additions should reflect projections previously submitted in support of the 2003 Revenue Requirement Application and the 2004 – 2008 PBR Application.

Subsequent to the repatriation of customer billing from BC Hydro last year, an error was discovered in the historic accounting for Rate 2 customers in the Lower Mainland. As noted in the 2003 application, this led to the need for a one-time adjustment for 1,283 transportation customers incorrectly recorded as Rate 2 customers in the Lower Mainland service area. This correction also relates to transportation customers that had been also identified (and therefore double counted) as sales customers in billing reports from B.C. Hydro. Since overall volumes for the Rate 2 customers were reported correctly, this error resulted in a lower and offsetting assumed use per account for determining rates and in the recorded results. The use per account for this customer class has therefore been adjusted upward to maintain an overall neutral impact between volume and revenue. Corrected estimates of account totals for Rate 2 are reflected in the 2004 forecast.

The table below provides a summary of the Residential and Commercial customer additions for the last 3 years, a projection for 2003 and the 2004 forecast customer additions. It also shows adjustments for reconnections and the BC Hydro System Repatriation as well as year-to-year changes in housing starts and population growth.

Total Year End Customer Additions - Rates 1, 2, and 3/23

All Regions Excluding Fort Nelson	Actual 2000	Actual 2001	Actual 2002	Projection 2003	Forecast 2004
Residential Additions	6,317	4,835	7,360	8,700	8,000
Commercial Additions	823	19	470	-890	500
Total Customers (Year End)	757,369	762,223	770,053	777,863	
Reconnection Adjustment				-4,000	
Rate 2 LM Repatriation Adjustment				-1,283	
Total Customers as Adjusted				772,580	781,080
Housing Starts	14,418	17,234	21,625	24,050	24,600
Population Growth (%)	0.9	0.8	1	1.4	1.4

4. USE PER CUSTOMER FORECAST

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

- The most recent historical normalized use per account;

- Customer migration between rates;
- Forecast use for new customer additions;
- Appliance conversion or replacement effects where applicable; and
- The estimated impact of demand side management programs over the forecast period.

In response to changes in customer lifestyle and the provincial demographic profile, Terasen Gas expects the proportionate share of multiple housing to increase over the next several years. Homeowner preference shifts toward apartment-style condominiums and townhouses, will put some further downward pressure on residential usage per account , and in some cases (e.g. strata developments) will lead to residential gas purchase collectives that effectively shift residential consumers into large commercial or industrial rate groupings.

With the higher gas prices in 2003, normalized residential use rates are currently tracking significantly below 2002 levels. Terasen Gas had forecast residential use per account to increase to 108 GJ in 2003 as the demand response to rising prices became more measured. Consumption normally recovers as the share of energy cost in the household budget is aligned with the new price level, but determination of the size and strength of any recovery is problematic. Analysis of the 2003 data available to date has led Terasen Gas to revise downward the forecast of residential usage by approximately 3 percent.

For commercial rate classes, usage per account has been flat during 2003. But there is evidence that normalized usage for Rate 3 and 23 customers is settling near 3,350 GJ, and 5,300 GJ per year respectively, while the average use-rate for Rate 2 customers appears stable at approximately 300 GJ.

As a result, Terasen Gas now assumes slightly lower baselines for each commercial usage from long-run energy conservation gains[4]. Although increased gas costs in 2003 make it difficult to accurately predict customer response, experience with commodity prices in 2000 and 2001 provides useful data for comparison. The modest recovery in residential customer use in 2002 was assumed to be lagged for commercial customers as a result of greater sensitivity to economic factors. However, since the 2003 year-end base continues to fall below previous expectation, Terasen Gas believes it prudent to adjust forecasted use rates for Rates 2, 3 and 23 downward to reflect what appears to be a permanent loss in gas demand. Aggregated mean usage for these customers is therefore expected to be about 2.3 percent above 2003.

[4] There is strong evidence of a permanent, conservation driven decline in base load for all commercial customers. Different base levels are clearly evident prior to and after the price shock of 2000-2001.

The competitive price perception of natural gas has eroded in recent years, notwithstanding that gas continues to be the most cost effective energy alternative for many applications. However, B.C. Hydro is planning to file a rate case by the end of the year, and this should lead to electricity rate increases as early as 2004. While the potential impact on consumer perceptions and choice is by no means certain, the Terasen Gas base forecast assumes that electricity rate increases will help preserve the relative competitiveness of natural gas as a heating energy source over the next few years.

In developing rates in the 2003 PBR filing, Terasen Gas used a forecast of 108 GJ for the average residential use per account. Accounting for the experience to date (August, 2003), and a projection to the end of the year, the average residential use rate for 2003 now appears to be closer to 100 GJ. With a decline in the number of low volume, non-heating users and some strengthening in the competitive position, Terasen has forecast that average residential use rates will approximate 104.7 GJ in 2004. Beyond 2004, a decline rate based on the historical average relating to technology improvements and conservation appears reasonable, but it remains difficult to gauge when a technology driven decline independent of price effect will recommence. If there is a fundamental change in the competitive position of natural gas, or if Terasen Gas is successful at building load through higher natural gas appliance penetration, then use per account declines are less likely.

As outlined above, a one-time adjustment for 1,283 transportation customers who were historically and incorrectly recorded as Rate 2 customers in the Lower Mainland service area has also been made for 2004. This correction relates to transportation customers that had been also identified (and therefore double counted) as sales customers in billing reports from B.C. Hydro. Since overall volumes for the Rate 2 customers were reported correctly, this error resulted in a lower assumed use-rate for determining rates. To maintain an overall neutral impact, the use per account has been adjusted concurrent with the reduction in Rate 2 customer numbers starting in 2004.

A summary of historic customer usage and the forecast use per account values are shown below, with all above referenced adjustments reflected in a higher forecast use per account for Rate 2 customers in 2004 and beyond. The forecast use per account values in the table below were used to develop the revenue forecasts in this Annual Review.

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

	Normal 1999	Normal 2000	Normal 2001	Normal 2002	Projected 2003	Forecast 2004
Rate 1	116.7	111.7	100.5	105.6	100.4	104.7
Rate 2	339.4	324.6	305.4	301.8	291.4	300.1
Rate 3	3,981.5	3,659.5	3,332.1	3,378.1	3,326.5	3,342.4
Rate 23	6,945.2	6,446.8	5,802.4	5,281.1	4,930.6	5,301.2

5. ENERGY FORECAST

a. Residential/Commercial

The residential and commercial energy forecast is calculated by multiplying the estimated customer energy use per account by the total number of customers including customer additions. From 2003, residential consumption is expected to rise marginally from 69.5 to 73.3 PJ while commercial use will remain flat at 44.1 PJ. The forecast for each year is provided in the summary table at the end of this section.

b. Industrial

Other than for Rate 5, the relatively small number of industrial customers favors the use of a customer survey methodology to produce the most reliable forecast. The industrial energy forecast is updated to include demand estimates provided by customers over the summer of 2003.

The forecast provided in support of the 2003 Annual Review predicts industrial energy consumption [excluding Burrard Thermal and Terasen Gas (Vancouver Island)] to decrease marginally to 58.2 PJ in 2003 from 59.4 PJ in 2002. Despite higher natural gas prices and a strengthening Canadian dollar, industrial load remains relatively stable. This derives partly from the fact that saw mills were able to maintain and even increase production in some regions. A clause in the import duty language that allowed Canadian companies to decrease applicable duties if they were able to decrease their overall costs per unit of wood may be affecting output. To decrease overall costs, mills opted to increase production spreading their fixed costs over a greater number of units, thus reducing their overall unit cost for determining anti-dumping duties. While this strategy varies with company-specific duties, it has helped maintain demand.

Given the new forest practices code that the B.C. government put into place in early 2003, the U.S. will likely relax their position by 2004. This will normalize production and return volumes to historic levels. Overall, the forecast of flat industrial demand for 2003 and 2004 is reasonable given the slow economic recovery and uncertainty facing energy intensive industries.

The recent survey of industrial customers suggests negligible growth over the duration of the current forecast, and statistical analysis of historical data supports this result. Surveys were gathered from 463 customers across every service region, rates class, and industry with no material difference between survey and historical projections.

The following table breaks out the energy forecast by Residential (Rate 1), Commercial (Rate 2 and 3/23), Firm Sales (Rate 4, 5, and 6) and Industrial (Rate 7, 22, 22A, 22B, 25 and 27) rate classes. The table shows that 2003 consumption should be consistent with the demand experience since the year 2000. In 2004 industrial demand will remain flat in response to the general environment of uncertainty, high energy cost, and conservation efforts of customers.

	Energy Forecast (PJ per annum)				
	Normal	**Normal**	**Normal**	**Projected**	**Forecast**
	2000	**2001**	**2002**	**2003**	**2004**
Residential	75.4	68.4	72.6	69.5	73.3
Commercial	47.3	43.9	44.3	43.0	44.1
Firm Sales	10.9	8.9	6.9	7.0	7.0
Industrial	58.9	55.6	59.4	58.2	57.8
Total	192.5	176.8	183.2	177.7	182.2

Industrial excludes Burrard and Centra

6. REVENUE FORECAST

Revenue forecasts for each customer class are developed from the total energy forecasts and the applicable rates. The revenue forecast below does not include amounts for Terasen Gas (Vancouver Island) and B.C. Hydro for Burrard Thermal.

The table below summarizes the 2003 Projection and 2004 Revenue Forecast by market segment and provides data from 2000-2002 for comparison purposes. Revenues increased substantially in 2001 due to the increases in the cost of gas, and Terasen Gas is forecasting an increase in total 2003 and 2004 revenues relative to 2002 for similar reasons.

Revenue Forecast ($000,000's)	Normal 2000	Normal 2001	Normal 2002	Projected 2003	Forecast 2004
Residential	611.0	780.3	702.3	754.3	839.9
Commercial	324.7	429.4	360.7	391.8	422.5
Firm Sales	60.8	79.8	51.3	60.3	63.3
Industrial	37.0	41.5	44.7	43.5	44.5
Total	1,033.5	1,331.0	1,159.1	1,249.9	1,370.2

Industrial excludes Burrard and Centra

7. MARGIN FORECAST

In 2003 and 2004, total margin is forecast to remain flat with the calculation incorporating approved rate increases and also customer growth. The table below breaks the forecast between Residential, Commercial, and Industrial Customers.

Margin Forecast ($000,000's)	Normal 2000	Normal 2001	Normal 2002	Projected 2003	Forecast 2004
Residential	237.1	250.8	264.0	265.0	275.3
Commercial	106.2	112.2	113.7	114.6	116.2
Firm Sales	15.7	14.1	12.3	12.9	12.8
Industrial	32.5	38.3	43.9	42.3	43.0
Total	391.5	415.4	433.8	434.8	447.3

Industrial excludes Burrard and Centra

8 SCP THIRD PARTY REVENUES

The SCP revenue forecast is unchanged from the 2004 – 2008 PBR filing. SCP Third Party firm revenues have been increased effective November 1, 2004 for a new contract replacing the canceled PG&E Energy Trading contract. For 2004, SCP Third Party firm revenues are forecast to be $7.8 million.

Additional SCP mitigation revenue margin remains forecast at $1 million per year.

Variances from forecast in SCP Third Party revenues continue to be subject to deferral treatment as indicated in the 2004–2007 Negotiated Settlement document.

9 MISCELLANEOUS REVENUE

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

Other recoveries are estimated at $910,000 per year, based on $750,000 from NRB recoveries, and $160,000 generated from advertising revenues.

10 BURRARD THERMAL REVENUE

Various Burrard Thermal agreements generate approximately $9.9 million in revenues annually. The transportation charge is fixed and independent of energy consumption.

11 TERASEN GAS (VANCOUVER ISLAND) REVENUE

Revenue from wheeling demand charges and odorant cost recovery remains at about $4 million per year.

12 SUMMARY

The updated forecast for 2004 reflects the best currently available information, and incorporates the following changes since the 2003 Revenue Requirement Application:

1. A one-time adjustment for Lower Mainland Rate Schedule 2 accounts reflected in the 2004 forecast year;

2. Revenues adjusted to reflect current rates including all approved 2003 permanent delivery rates and gas cost increases;

3. Customer counts adjusted to reflect the actual results to August 2003; and

4. SCP Third Party revenues adjusted to reflect the revenue change from the PG&E contract cancellation and the replacement contract.

5. Use per account for Rates 1, 2, 3, and 23 is adjusted for consumption trends to September 1, 2003.

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2004

Line No.	Particulars	2003 Decision	2004 Terajoules Core and Non-Core	2004 Terajoules Bypass and Special Rates	2004 Terajoules Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(5)	(6)
1	SALES						
2	Schedule 1 - Residential	75,045.4	73,250.9	0.0	73,250.9	(1,795)	
3	Schedule 2 - Small Commercial	23,809.3	21,289.4	0.0	21,289.4	(2,520)	
4	Schedule 3 - Large Commercial	20,078.5	18,596.0	0.0	18,596.0	(1,483)	
5							
6	Total Schedules 1, 2 and 3	118,933.2	113,136.3	0.0	113,136.3	(5,796.9)	
7							
8	Schedule 4 - Seasonal Service	146.3	234.4	0.0	234.4	88	
9	Schedule 5 - General Firm Service	6,279.8	6,404.5	0.0	6,404.5	125	
10							
11	Industrials						
12	Schedule 7 - Interruptible	118.2	121.5	0.0	121.5	3	
13							
14	Schedule 10	0.0	0.0	0.0	0.0	0	
15							
16	Total Industrials	118.2	121.5	0.0	121.5	3.3	
17							
18	Schedule 6 - N G V Fuel - Stations	557.0	268.5	0.0	268.5	(289)	
19							
20	Total Sales	126,034.5	120,165.2	0.0	120,165.2	(5,869.3)	- Tab 1, Page 6
21							
22	TRANSPORTATION SERVICE						
23	Schedule 22 - Firm Service	49,559.1	9,954.3	42,903.2	52,857.5	3,298	
24	- Interruptible Service	17,648.0	15,798.5	0.0	15,798.5	(1,850)	
25	Schedule 23 - Large Commercial	3,816.2	4,208.7	0.0	4,208.7	393	
26	Schedule 25 - Firm Service	11,898.6	10,529.8	1,796.6	12,326.4	428	
27	Schedule 27 - Interruptible	6,082.6	6,566.8	0.0	6,566.8	484	
28	Terasen Gas (Vancouver Island)	36,553.3	0.0	39,357.3	39,357.3	2,804	
29	Columbia Service Area - Byron Creek	158.7	0.0	158.7	158.7	0	
30							
31	Total Transportation Service	125,716.5	47,058.1	84,215.8	131,273.9	5,557.4	- Tab 1, Page 6
32							
33	TOTAL SALES AND TRANSPORTATION SERVICE	251,751.0	167,223.3	84,215.8	251,439.1	(311.9)	- Tab 1, Page 6

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004 Gas Sales Revenue At Existing Rates: Core and Non-Core	2004 Gas Sales Revenue At Existing Rates: Bypass and Special Rates	2004 Gas Sales Revenue At Existing Rates: Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	SALES						
2	Schedule 1 - Residential	$724,336	$839,979	$0	$839,979	115,643	
3	Schedule 2 - Small Commercial	214,477	229,934	0	229,934	15,457	
4	Schedule 3 - Large Commercial	162,163	183,004	0	183,004	20,841	
5							
6	Total Schedules 1, 2 and 3	1,100,976	1,252,917	0	1,252,917	151,941	
7							
8	Schedule 4 - Seasonal Service	1,008	2,100	0	2,100	1,092	
9	Schedule 5 - General Firm Service	46,828	58,756	0	58,756	11,928	
10		47,836	60,856	0	60,856	13,020	
11	Industrials						
12	Schedule 7 - Interruptible	820	1,050	0	1,050	230	
13							
14	Schedule 10	0	0	0	0	0	
15							
16							
17	Total Industrials	820	1,050	0	1,050	230	
18							
19	Schedule 6 - N G V Fuel - Stations	4,377	2,720	0	2,720	(1,657)	
20							
21	Total Sales	1,154,009	1,317,543	0	1,317,543	163,534	- Tab 1, Page 6
22							
23	TRANSPORTATION SERVICE						
24	Schedule 22 - Firm Service	19,035	8,199	11,100	19,299	264	
25	- Interruptible Service	9,986	10,092	0	10,092	106	
26	Schedule 23 - Large Commercial	8,159	9,604	0	9,604	1,445	
27	Schedule 25 - Firm Service	16,673	16,246	832	17,078	405	
28	Schedule 27 - Interruptible	6,045	6,685	0	6,685	640	
29	Terasen Gas (Vancouver Island)	0	0	0	0	0	
30	Columbia Service Area - Byron Creek	0	0	0	0	0	
31							
32	Total Transportation Service	59,898	50,826	11,932	62,758	2,860	- Tab 1, Page 6
33							
34	TOTAL SALES AND TRANSPORTATION SERVICE	$1,213,907	$1,368,369	$11,932	$1,380,301	$166,394	- Tab 1, Page 6

TERASEN GAS INC. - SUMMARY BY SERVICE AREA

COST OF GAS BY RATE SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2004

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CORE AND NON-CORE										
2	Core and Non-Core Sales										
3	Schedule 1 - Residential	53,103.4	$7.7300	$410,489	18,043.6	$7.6394	$137,842	2,103.9	$7.7110	$16,223	$564,554
4	Schedule 2 - Small Commercial	15,247.9	7.7993	118,923	5,325.9	7.7099	41,062	715.6	7.7777	5,566	165,551
5	Schedule 3 - Large Commercial	15,198.4	7.5781	115,175	3,065.1	7.5084	23,014	332.5	7.5644	2,515	140,704
6	Schedules 1, 2 and 3	83,549.7		644,587	26,434.6		201,918	3,152.0		24,304	870,809
7											
8	Schedule 4 - Seasonal	109.3	7.3376	802	125.1	7.2509	907.0	0.0	7.3297	0	1,709
9	Schedule 5 - General Firm	5,261.9	7.3387	38,616	988.3	7.2510	7,166	154.3	7.3297	1,131	46,913
10											
11	Industrial										
12	Interruptible - Schedule 7	100.1	7.3427	735	21.4	7.2430	155	0.0	0.0000	0	890
13	- Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
14	Total Industrials	100.1		735	21.4		155	0.0		0	890
15											
16	N G V Fuel - Stations - Schedule 6	245.8	7.0597	1,735	22.7	6.9906	159	0.0	6.9906	0	1,894
17											
18	Total NGV	245.8		1,735	22.7		159	0.0		0	1,894
19											
20	Total Core and Non-Core Sales	89,266.8		686,475	27,592.1		210,305	3,306.3		25,435	922,215
21											
22	Core and Non-Core Transportation Service										
23	Schedule 22 - Firm Service	292.8	0.0316	9	7,090.7	(0.0253)	(179)	2,570.8	0.1073	276	106
24											
25	- Interruptible Service	13,893.4	0.0316	438	1,656.7	(0.0253)	(42)	248.4	0.1073	27	423
26											
27	Schedule 23 - Large Commercial	3,337.5	0.0316	105	864.8	(0.0253)	(22)	6.4	0.1073	1	84
28	Schedule 25 - Firm Service	6,858.9	0.0316	217	3,370.2	(0.0253)	(85)	300.7	0.1073	32	164
29	Schedule 27 - Interruptible Service	5,856.6	0.0316	185	493.1	(0.0253)	(12)	217.1	0.1073	23	196
30	Total Core and Non-Core T-Service	30,239.2		954	13,475.5		(340)	3,343.4		359	973
31											
32											
33	Total Core and Non-Core Sales and										
34	Transportation Service										
35	Cost of Gas Sold	119,506.0		$687,429	41,067.6		$209,965	6,649.7		$25,794	$923,188

TERASEN GAS INC. - SUMMARY BY SERVICE AREA

COST OF GAS BY RATE SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2004

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000)	Total Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	BYPASS AND SPECIAL RATES										
2	Bypass and Special Rates Sales										
3	Schedule 4 - Seasonal	0.0	$0.0000	$0	0.0	$0.0000	$0	0.0	$0.0000	$0	$0
4											
5	Large Industrial										
6	Interruptible - Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
7											
8											
9	Total Large Industrial	0.0		0.0	0.0		0.0	0.0		0.0	0
10	Total Bypass and Spec. Rates Sales	0.0		0.0	0.0		0.0	0.0		0.0	0
11											
12	Bypass and Special Rates Transportation Service										
13	Schedule 22 - Firm Service	0.0	0.0316	0	12,175.1	(0.0253)	(306)	363.4	0.1073	39	(267)
14											
15	- Interruptible Service	0.0	0.0316	0	0.0	(0.0253)	-	0.0	0.1073	0	0
16											
17	- Burrard Thermal - Firm	30,364.7	0.0158	479	0.0		0	0.0		0	479
18	Schedule 23 - Large Commercial	0.0	0.0316	0	0.0	(0.0253)	0	0.0	0.1073	0	0
19	Schedule 25 - Firm Service	0.0	0.0316	0	1,796.6	(0.0253)	(45)	0.0	0.1073	0	(45)
20	Schedule 27 - Interruptible Service	0.0	0.0316	0	0.0	(0.0253)	0	0.0	0.1073	0	0
21	Byron Creek	0.0	0.0000	0	0.0	0.0000	0	158.7	0.1073	17	17
22	Terasen Gas (Vancouver Island)	39,357.3	0.0158	621							621
23	Total Bypass and Spec. Rates T-Svc	69,722.0		1,100	13,971.7		(351)	522.1		56	805
24											
25											
26	Total Bypass and Special Rates Sales and										
27	Transportation Service										
28	Cost of Gas Sold	69,722.0		1,100	13,971.7		(351)	522.1		56	805
29											
30	Total Sales and Transportation										
31	Transportation Service										
32	Cost of Gas Sold	189,228.0		$688,529	55,039.3		$209,614	7,171.8		$25,850	$923,993

TERASEN GAS INC..
REVENUE AND GROSS MARGIN AT EXISTING 2003 RATES
AND ALLOCATION OF REVENUE REQUIREMENT INCREASE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Terajoules	Revenue -- At Existing Rates Average $/GJ	Revenue -- At Existing Rates Revenue ($000)	Gross Margin -- At Existing Rates Average $/GJ	Gross Margin -- At Existing Rates Revenue ($000)	Increase / (Decrease) 3.91% $/GJ	Increase / (Decrease) of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Core and Non-Core										
2	Core and Non-Core Sales										
3	Schedule 1 - Residential	73,250.9	$11.467	$839,979	$3.7600	$275,424	$0.1469	$10,761	699,308	$11.614	$850,740
4	Schedule 2 - Small Commercial	21,289.4	10.800	229,934	3.0242	64,383	0.1181	2,515	70,952	10.918	232,449
5	Schedule 3 - Large Commercial	18,596.0	9.841	183,004	2.2747	42,300	0.0889	1,653	5,555	9.930	184,657
6											
7	Total Schedules 1 , 2 and 3	113,136.3		1,252,917		382,107		14,929			1,267,846
8											
9											
10	Schedule 4 - Seasonal Service	234.4	8.959	2,100	1.6681	391	0.0683	16	17	9.027	2,116
11	Schedule 5 - General Firm Service	6,404.5	9.174	58,756	1.8492	11,843	0.0721	462	527	9.246	59,218
12											
13	Industrials										
14	Schedule 7 - Interruptible	121.5	8.642	1,050	1.3169	160	0.0494	6	6	8.691	1,056
15											
16	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
17											
18	Total Industrials	121.5		1,050		160		6			1,056
19											
20											
21	Schedule 6 - N G V Fuel - Stations	268.5	10.130	2,720	3.0764	826	0.1192	32	48	10.249	2,752
22	- VRA's	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
23											
24	Total Core and Non-Core Sales	120,165.2		1,317,543		395,327		15,445	776,413		1,332,988
25											
26	Core and Non-Core Transportation Service										
27	Schedule 22 - Firm Service	9,954.3	0.824	8,199	0.8130	8,093	0.0317	316	18	0.856	8,515
28	- Interruptible Service	15,798.5	0.639	10,092	0.6120	9,669	0.0239	377	29	0.663	10,469
29	Schedule 23 - Large Commercial	4,208.7	2.282	9,604	2.2620	9,520	0.0884	372	796	2.370	9,976
30	Schedule 25 - Firm Service	10,529.8	1.543	16,246	1.5273	16,082	0.0597	629	410	1.603	16,875
31	Schedule 27 - Interruptible Service	6,566.8	1.018	6,685	0.9882	6,489	0.0387	254	93	1.057	6,939
32											
33	Total Core and Non-Core Transportation Service	47,058.1		50,826		49,853		1,948	1,346		52,774
34											
35	Total Core and Non-Core Sales and										
36	Transportation Service	167,223.3		$1,368,369		$445,180		$17,393	777,759		$1,385,762

TERASEN GAS INC..
REVENUE AND GROSS MARGIN AT EXISTING 2003 RATES
AND ALLOCATION OF REVENUE REQUIREMENT INCREASE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Terajoules	Revenue -- At Existing Rates Average $/GJ	Revenue -- At Existing Rates Revenue ($000)	Gross Margin -- At Existing Rates Average $/GJ	Gross Margin -- At Existing Rates Revenue ($000)	Increase / (Decrease) 3.91% of Margin $/GJ	Increase / (Decrease) 3.91% of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Bypass and Special Rates										
2											
3	Bypass and Special Rates - Sales										
4	Residential - Option A	0.0	$0.000	$0	$0.0000	$0	$0.000	$0	0	$0.000	$0
5	Schedule 4 - Seasonal Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
6	Schedule 5 - General Firm Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
7	Industrials										
8	Schedule 7 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
9											
10	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
11											
12	Total Large Industrial	0.0		0		0		0			0
13											
14	Schedule 6 - N G V Fuel - Stations	0.0	0.000	0	0.0000	0	0	0	0	0.000	0
15	- VRA's	0.0	0.000	0	0.0000	0	0	0	0	0.000	0
16											
17	Total Bypass and Special Rates Sales	0.0		0		0		0	0		0
18											
19	Bypass and Special Rates Transportation Service										
20	Schedule 22 - Firm Service	12,538.5	0.098	1,229	0.1194	1,497	0	0	1	0.098	1,229
21	Schedule 22 - Interruptible	0.0	0.000	0	0.0000	0	0	0	9	0.000	0
22	Schedule 25 - Interruptible	1,796.6	0.463	832	0.4881	877	0	0	7	0.463	832
23	Columbia - Byron Creek	158.7	0.000	0	(0.1071)	(17)	0	0	1	0.000	0
24	Burrard Transportation - Firm	30,364.7	0.325	9,871	0.3093	9,392	0	0	1	0.325	9,871
25	Terasen Gas (Vancouver Island)	39,357.3	0.102	4,025	0.0865	3,404	0	0	1	0.102	4,025
26	SCP Third Party Revenues			8,820		8,820		0			8,820
27	Total Bypass and Special Rates Transportation Service	84,215.8		24,777		23,973		0	20		24,777
28											
29	Total Bypass and Special Rates Sales and										
30	Transportation Service	84,215.8		24,777		23,973		0	20		24,777
31											
32											
33	TOTAL SALES AND TRANSPORTATION SERVICE	251,439.1		$1,393,146		$469,153		$17,393	777,779		$1,410,539

TERASEN GAS INC.

**2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2004 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT**

SECTION A-5 INDEX

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
2004 OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2004

In accordance with the PBR settlement, the 2004 operating and maintenance costs are determined on a formula-based approach, as in the 1998-2001 PBR Plan, that start from a base of the 2003 Decision O&M, escalated by growth in customers and inflation less an adjustment factor of 50% of CPI (BC). The forecast of 2004 inflation based on CPI (BC) is 1.7% as discussed under Section A, Tab 2.

For 2004, the annual operating and maintenance expenses are based on the following formula:

Gross O&M = 2003 Decision O&M + TPIP X [(1 + customer growth) X (1 + CPI – adjustment factor)] + Pension & Insurance Variance

Gross 2004 O&M	$ 187.884 million
Capitalized Overhead	(26.009) million
Fort Nelson O&M and Vehicle Lease	(2.458) million
Net 2004 O&M	$ 159.417 million

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

As per BCUC Order No. G-51-03, Appendix A, Page 6, ongoing pipeline integrity costs (TPIP) have been included as 2004 O&M expenses. Variances between PBR formula based pension and insurance costs and cost of service based have also been included as 2004 O&M expenses.(Section A, Tab 5, Page 3)

Consistent with the 2003 Decision and the terms of the Settlement, the Company has kept the overheads capitalized rate at 16% for the 2004 year.

TERASEN GAS INC..

FORMULA CALCULATION OF
OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000) - Except where noted

Line No.	Description		2003 Decision Adjusted for TPIP	Change	2004
	(1)		(2)	(3)	(4)
1	Average Number of Customers		770,368	7,411	777,779
2	Percentage Growth in Average Customers			0.96%	
3					
4	Annual Inflation Rate - CPI			1.70%	
5	Adjustment Factor			0.85%	
6					
7	Total Gross O & M Expense before TPIP		$176,915		
8	TPIP		5,505		
9	Total Gross O & M Expense		182,420	$3,320	$185,740
10	Pension & Insurance Variance			2,144	2,144
11	Adjusted Total Gross O&M Expense				187,884
12					
13	Less: Items Not Subject to Overheads				
14	Fort Nelson	($581)			
15	Vehicle Lease	(1,833)			
16	DRIA	(1,652)			
17	OPEB	(6,329)			
18	Capital-related Portion - CustomerWorks	(8,978)			
19	Total Items Not Subject to Overheads	($19,373)	(19,373)		(19,726)
20	Less: TPIP Not Subject to Overhead		(5,505)		(5,605)
21	Total O&M Subject to Capitalized Overhead		157,542	5,011	162,553
22					
23	Capitalized Overhead at 16%		25,207		26,009
24	Gross O&M Less Capitalized Overhead		157,213	4,662	161,875
25					
26	Less: Fort Nelson		(581)	(11)	(592)
27	Vehicle Lease		(1,833)	(33)	(1,866)
28	Total Utility O&M		$154,799	$4,618	$159,417

TERASEN GAS INC.
PENSION AND INSURANCE VARIANCE FROM FORMULA
PBR vs COST OF SERVICE BASED
($000) - Except where noted

Line No.	Particulars	2003 Decision	Change	2004 Forecast	Reference
	(1)	(2)	(3)	(4)	(5)
1	Average Number of Customers	770,368	7,411	777,779	
2	Percentage Growth in Average Customers		0.96%		
3					
4					
5	Annual Inflation Rate - CPI		1.70%		
6	Productivity		0.85%		
7					
8	**PBR Formula Based**				
9	Pension Expense	$ 5,543		$ 5,644	
10	Insurance Expense	3,661		3,728	
11		9,204		9,372	
12	**Cost of Service Based**				
13	Pension Expense			$ 5,616	
14	Insurance Expense			5,900	
15				11,516	
16					
17	Difference			$ 2,144	- Tab 5, Page 2

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2004 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-6 INDEX

1. Property Tax Expense

Under the 2004 – 2007 PBR, property taxes are to be forecast each year for the Annual Review process. The Property Tax deferral account will collect variances from the forecast amount included in rates.

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

1% Tax

The 1% tax in lieu of general municipal taxes ("1% tax") is calculated based on the amount of revenues collected within municipal boundaries multiplied by 1% (1.25% for the City of Vancouver). Payments of the 1% tax to municipalities are lagged relative to increases and decreases in revenues due to provisions in the applicable legislation and agreements. Rate decreases in October 2001 and January 2002 and the associated lower revenues affect the 1% tax in 2004. The April 1, 2003 gas cost flow-through rate increase will only affect the 1% tax payments for Vancouver since the payment lag is less.

General, School and Other:

Property taxes include general, school and other property taxes as well as Oil and Gas Commission fees. Assessed values for assets other than transmission pipe and land are estimated using 2003 actual assessments and market adjustments of 1-2%. The only exception to market based adjustments in 2004 relates to transmission pipeline where assessments are expected to increase by 5% in 2004. The actual overall transmission pipeline increase is estimated at 13.5%, however, this is expected to be phased in over a 3 year period. The change is a result of a review undertaken by BC Assessment on the legislated pipeline rates, and consultation with various pipeline companies including Terasen Gas Inc. Mill rates for general property taxes are forecast to increase by 1% to 1.5% annually and are set separately by each local government taxation authority. The provincial government sets school tax rate and no change is expected in 2004. Other property taxes are collected by local government taxation authorities on behalf of other taxation authorities such as regional districts and hospitals and are expected to increase by 2% in 2004.

Beyond the larger increases forecast transmission assets, normal year-to-year inflation in other categories and revenue-driven changes in the 1% tax no additional property tax increases are included. As indicated in the Application section, Terasen Gas seeks continuation of the deferral account treatment for variances in property taxes from forecast.

2. B.C. Corporation Capital Tax (CCT)

<u>Corporate Capital Tax Expense</u>:

On July 30, 2001, the Ministry of Finance of the Province of British Columbia announced that it would phase out the corporate capital tax on non-financial institutions over two years. With the elimination of the CCT by September 1, 2002, no provision for CCT expense has been made for 2004. The Company has been re-assessed for CCT in prior periods and is currently in the process of appealing these assessments.

3. Large Corporations Tax (LCT)

LCT is calculated based on taxable capital determined pursuant to the applicable sections of the *Income Tax Act* at a rate of 0.200% for 2004. For details, see Section A, Tab 6, Page 8. LCT is reduced by the Federal corporate surtax calculated in accordance with the applicable provisions of the *Income Tax Act*.

4. Income Tax Expense

Income tax expense is determined based on taxable earnings calculated on the basis of revenues and costs in accordance with the applicable provisions of the *Income Tax Act*, multiplied by the combined provincial and federal income tax rates. For regulatory purposes, income tax expense is calculated following the taxes payable method of accounting for income taxes. For 2004, the combined corporate income tax rate is set at 35.62% (including 1.12% surtax), a 2% reduction from the 2003 level.

TERASEN GAS INC..

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	B.C.U.C. Account Number	2003 Decision	2004 Total Expenses	2004 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Property Taxes	305-010					
2							
3	1% in Lieu of General Municipal Tax		15,120	$13,090	$13,090	($2,030)	
4							
5	General, School and Other		26,093	26,330	26,330	237	
6							
7	Amortization of Property Tax Deferral		0	0	0	0	
8							
9			41,213	39,420	39,420	(1,793)	
10							
11	B.C. Corporation Capital Tax		0	0	0	0	
12							
13	Total		$41,213	$39,420	$39,420	($1,793)	- Tab 1, Page 6

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004 Existing Rates	2004 ----Revised Rates----- Revised Revenue	2004 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$179,221	$161,231	$11,397	$172,628	($6,593)	- Tab 1, Page 6
3	Deduct - Interest on Debt	(108,637)	(104,306)	(13)	(104,319)	4,318	
4	Add- Non-Tax Ded. Expense (Net)	2,191	262	0	262	(1,929)	- Tab 6, Page 5
5							
6	Accounting Income After Tax	72,775	57,187	11,384	68,571	(4,204)	
7	Add (Deduct) - Timing Differences	(13,976)	(6,616)	0	(6,616)	7,360	- Tab 6, Page 5
8	Add - Large Corporation Tax	4,044	3,629	(195)	3,434	(610)	- Tab 6, Page 8
9							
10	Taxable Income After Tax	$62,843	$54,200	$11,189	$65,389	$2,546	
11							
12							
13	Income Tax Rate (Current Tax)	37.620%	35.620%	35.620%	35.620%	-2.000%	
14	1 - Current Income Tax Rate	62.380%	64.380%	64.380%	64.380%	2.000%	
15							
16	Deferred Income Tax	0	0	0	0	0	
17							
18	Taxable Income (L10 : L14)	$100,742	$84,187	$17,380	$101,567	$825	
19							
20							
21	Income Tax- Current (L18 x L13)	$37,899	$29,987	$6,191	$36,178	($1,721)	
22							
23	- Large Corporation Tax	4,044	3,629	(195)	3,434	(610)	- Tab 6, Page 8
24							
25	Total	$41,943	$33,616	$5,996	$39,612	($2,331)	- Tab 1, Page 6
26							
27	REVENUE DEFICIENCY						
28	Earned Return			$11,397	$172,628		- Tab 1, Page 6
29	Add - Income Taxes			5,996	39,612		- Tab 1, Page 6
30	Deduct - Utility Income Before Taxes,						
31	Present Rates			0	(194,847)		- Tab 1, Page 6
32	Corporate Capital Tax			0	0		
33							
34	Deficiency After Corporate Capital Tax			$17,393	$17,393		

TERASEN GAS INC.
NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME				
2					
3	Amortization of Deferred Charges	$171	($411)	($582)	-Tab 3, Page 11.1
4					
5	Less: Deferred Interest Amortization	1,359	0	(1,359)	
6					
7					
8					
9					
10					
11	Non-tax Deductible Expenses	661	673	12	
12					
13					
14					
15	Total Permanent Differences	$2,191	$262	($1,929)	-Tab 1, Page 7
16					
17	TIMING DIFFERENCE ADJUSTMENTS				
18					
19	Depreciation	$72,905	$79,296	$6,391	- Tab 6, Page 6
20	Less - Vehicle Costs Charged to Depreciation Expense	0	0	$0	
21	Amortization of Debt Issue Expenses	1,446	1,611	$165	
22	Debt Issue Costs	(1,772)	(902)	$870	
23	Capital Cost Allowance	(77,770)	(77,331)	$439	- Tab 6, Page 7
24	Cumulative Eligible Capital Allowance	(1,131)	(1,500)	($369)	
25	Add Back Principle Portion of Coastal Facilities Lease Payments	1,063	1,063	$0	
26	Short Term Debt Issue Costs	735	0	($735)	
27	Unfunded Pension	0	900	$900	
28	Overheads Capitalized Expensed for Tax Purposes	(9,452)	(9,753)	($301)	
29					
30	Total Timing Differences	($13,976)	($6,616)	$7,360	-Tab 1, Page 7

TERASEN GAS INC..
DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	2003 Decision	2004	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	Depreciation Provision				
2					
3	Total Depreciation Expense	$81,492	$89,103	$7,611	
4					
5	Less: Amortization of Contributions in Aid of Construction	(8,587)	(9,807)	(1,220)	
6		72,905	79,296	6,391	
7					
8	- Vehicle Costs Charged to Depreciation Expense	0	0	0	
9					
10		72,905	79,296	6,391	- Tab 6, Page 5
11					
12	Amortization Expense				
13					
14	Amortization of Deferred Charges	$171	($411)	($582)	- Tab 3, Page 11.1
15					
16					
17		171	(411)	(582)	
18					
19	TOTAL	$73,076	$78,885	$5,809	- Tab 1, Page 6

TERASEN GAS INC..
CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Class	CCA Rate %	12/31/2003 UCC Balance	2004 Net Additions	2004 CCA	12/31/2004 UCC Balance
(1)	(2)	(3)	(4)	(5)	(6)
1	4%	$1,255,637	$77,976	($51,785)	$1,281,828
2	6%	237,958	0	(14,277)	223,681
3	5%	3,845	0	(192)	3,653
6	10%	386	0	(39)	347
8	20%	18,338	3,932	(4,061)	18,209
9	25%	3	0	(1)	2
10	30%	16,669	7,144	(6,072)	17,741
12	100%	0	0	0	0
13		7,249	0	(855)	6,394
14		10	0	(2)	8
17	8%	369	0	(30)	339
29	100%	0	0	0	0
38	30%	55	0	(17)	38
39	25%	1	0	0	1
	Total	$1,540,520	$89,052	($77,331)	$1,552,241

CALCULATION OF LARGE CORPORATION TAX
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Reference	2003 Decision	2004 Existing Rates	2004 Revised Rates	Change
	(1)	(2)	(3)	(4)	(5)	(6)
1	Large Corporation Tax					
2						
3	Utility Capital (Line 26)		2,290,524	$2,314,332	$2,314,637	24,113
4	Add: Security Deposits		2,611	3,966	3,966	1,355
5	Long Term Construction Advances		700	525	525	(175)
6	Deferred Income Tax		364	364	364	0
7	Work in Progress Attracting AFUDC		14,000	14,000	14,000	0
8	Sub-total		2,308,199	2,333,187	2,333,492	25,293
9						
10	Utility Portion of $10,000,000 or $50,000,000 Deduction					
11	(Line 38 x $10,000,000 or $50,000,000)		(9,445)	(47,345)	(47,345)	(37,900)
12						
13	Taxable Capital		$2,298,754	$2,285,842	$2,286,147	($12,607)
14						
15	Large Corporation Tax Rate		0.225%	0.200%	0.200%	-0.025%
16						
17	Large Corporation Tax		5,172	$4,572	$4,572	(600)
18	Less: Surtax	1.12%	(1,128)	(943)	(1,138)	(10)
19						
20	Large Corporation Tax		$4,044	$3,629	$3,434	($610)
21						
22						
23	Net Plant in Service, Ending	Tab 1, Page 5	2,171,388	$2,203,763	$2,203,763	32,375
24	All Other Rate Base Items - Lines 26 - 31 of	Tab 1, Page 5	119,136	110,569	110,874	(8,262)
25						
26	Utility Capital		2,290,524	2,314,332	2,314,637	24,113
27						
28	Non-Rate Base Items					
29	Net Book Value of Lower Mainland Premium		121,008	116,708	116,708	(4,300)
30	Disallowed Plant Costs		2,444	2,344	2,344	(100)
31	Plant Held for Future Use		0	0	0	0
32	Fort Nelson Division		4,800	4,284	4,284	(516)
33	Squamish Gas Co. Ltd.		6,400	6,550	6,550	150
34						
35	Total Capital		$2,425,176	$2,444,219	$2,444,524	$19,348
36						
37						
38	Proportion of Utility Capital to Total Capital		94.45%	94.69%	94.69%	0.24%

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
2004 REVENUE REQUIREMENTS AND
OTHER INFORMATION PERTAINING TO THE SETTLEMENT

SECTION A-7 INDEX

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
2004 RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2004

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

Long-Term Debt

A $150 million long-term debt issue with a coupon rate of 6.25% is planned for September 30, 2004.

Unfunded Debt

The unfunded debt rate for 2004 is set at 3.25% based on the current outlook for short-term rates in the year.

Common Equity

The calculations in this Application have made use of an ROE of 9.0%, a recent estimate of the ROE that would be in effect if ROE were set using current Long Canada Bond yields. The 2004 rates applied for in this Application will be adjusted for any differences between 9.0% and the approved ROE arising from the BCUC ROE adjustment mechanism, which will be set in December 2003.

TERASEN GAS INC..

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	12-03-1990	09-30-2015	11.800%	$58,943	$855	$58,088	12.054%	$58,943	$7,105	
2	Series B Purchase Money Mortgage	11-30-1991	11-30-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	2003 Medium Term Note -Series 17	09-26-2003	09-26-2005	3.600%	150,000	481	149,519	3.767%	150,000	5,651	
5	2004 Long Term Debt Issue	09-30-2004	09-30-2014	6.250%	150,000	1,500	148,500	6.387%	37,808	2,415	
6	Series F Debentures	08-26-1992	08-26-2002	8.500%	83,980	984	82,996	8.678%	0	0	
7	Series H Debentures	07-28-1993	07-28-2003	8.150%	50,000	507	49,493	8.301%	0	0	
8											
9	Medium Term Note - Series 6	02-09-1995	02-09-2005	9.800%	20,000	380	19,620	10.106%	20,000	2,021	
10	Medium Term Note - Series 6	03-15-1995	02-09-2005	9.800%	20,000	(387)	20,387	9.494%	20,000	1,899	
11	Medium Term Note - Series 7	06-29-1995	06-29-2005	8.250%	5,000	100	4,900	8.550%	5,000	428	
12											
13	Medium Term Note - Series 9	10-21-1997	06-02-2008	6.200%	55,000	454	54,546	6.308%	55,000	3,469	
14	Med.Term Note - Series 9 (Re-opened)	11-19-1998	06-02-2008	6.200%	58,000	681	57,319	6.036%	58,000	3,501	
15	Med.Term Note - Series 9 (Re-opening)	09-21-1999	06-02-2008	6.200%	75,000	2,053	72,947	6.578%	75,000	4,933	
16	Medium Term Note - Series 11	09-21-1999	09-21-2029	6.950%	150,000	2,137	147,863	7.065%	150,000	10,597	
17											
18	Medium Term Note - Series 12	07-20-2000	07-20-2005	6.500%	200,000	2,622	197,378	6.814%	200,000	13,628	
19	Medium Term Note - Series 13	10-16-2000	10-16-2007	6.500%	100,000	728	99,272	6.632%	100,000	6,632	
20	Medium Term Note - Series 14	10-23-2000	10-23-2003	6.000%	50,000	428	49,572	6.317%	0	0	
21	Medium Term Note - Series 15	12-11-2000	12-11-2002	6.000%	75,000	229	74,771	6.177%	0	0	
22	Medium Term Note - Series 16	07-30-2001	07-31-2006	6.150%	100,000	721	99,279	6.320%	100,000	6,320	
23	LILO Obligations - Kelowna							6.969%	30,048	2,094	
24	LILO Obligations - Nelson							6.969%	4,995	348	
25	LILO Obligations - Vernon							7.155%	15,994	1,144	
26									$1,238,062	$88,637	
27	Debentures										
28	Series D	12-17-1986	12-17-2006	9.750%	20,000	244	19,756	9.945%	20,000	1,989	
29	Series E	06-08-1989	06-07-2009	10.750%	59,890	637	59,253	10.927%	59,890	6,544	
30									79,890	8,533	
31											
32	Sub-Total								1,317,952	97,170	
33	Less - Fort Nelson Division Portion of Long Term Debt								(2,535)	(187)	
34	Total								$1,315,417	$96,983	7.373%

TERASEN GAS INC.

2004 – 2007 PERFORMANCE BASED RATE SETTLEMENT AGREEMENT
REVISED FORECASTS AND PROJECTIONS FOR
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SECTION A-8 INDEX

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
2003 PROJECTIONS AFFECTING 2004 RATES
FOR THE YEAR ENDING DECEMBER 31, 2004

The 2003 projected ending account balances form the 2004 opening account balances. The attached schedules include the continuity of 2003 account balances for gross plant-in-service, accumulated depreciation and amortization, contributions in aid of construction and deferrals .

The December 31, 2003 projected plant balances include:

- 2003 CPCN Opening Additions of $27.0 million
- Base Capital Additions of $117.7 million
- Plant Depreciation of $79.7 million
- Contribution in Aid of Construction Amortization of $8.1 million

The Overhead Charged to Construction account (approximately $200 million as of December 31, 2002) has been allocated at the end of 2003 to the individual non-general plant accounts on the basis of historic plant balances (see Section A, Tab 8, Pages 2 to 2.1 for the Overhead Adjustment). Similarly, the 2003 Capitalized Overhead has been allocated to the non-general plant accounts.

TERASEN GAS INC..

Section A
Tab 8
Page 2

GAS PLANT IN SERVICE
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	Balance 12/31/2002	OH Adjustment	CPCN'S	Projected 2003 Additions	Retirements	Balance 12/31/2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	401 Franchise Consents	$99	0	$0	$0	$0	$99
2	402 Other Intangible Plant	770	-	0	0	0	770
3	TOTAL INTANGIBLE PLANT	869	0	0	0	0	869
4							
5	430 Manufact'd Gas - Land	31	0	0	0	0	31
6	432 Manufact'd Gas - Struct. & Improvements	431	5	0	0	0	436
7	433 Manufacturing Equipment	139	0	0	0	0	139
8	434 Gas Holders - Manufacturing	353	5	0	0	0	358
9	436 Compressed Equipment	53	0	0	0	0	53
10	437 Measuring and Regulating Equipment	295	4	0	0	0	299
11	440/441 Land in Fee Simple and Land Rights	915	12	0	0	0	927
12	442 Structures and Improvements	3,063	22	0	1,800	0	4,885
13	443 Gas Holders - Storage	15,714	706	0	99	0	16,519
14	446 Compressor Equipment	0	0	0	0	0	0
15	447 Measuring and Regulating Equipment	0	0	0	0	0	0
16	448 Purification Equipment	0	0	0	0	0	0
17	449 Local Storage Equipment	16,371	128	0	238	0	16,737
18	**TOTAL MANUFACTURED GAS / LOCAL STORAGE**	37,365	882	0	2,137	0	40,384
19							
20	460 Land in Fee Simple	3,993	3,765	0	32	0	7,790
21	461 Land Rights	28,083	963	1,209	7,251	0	37,506
22	462 Compressor Structures	13,155	170	850	175	0	14,350
23	463 Measuring Structures	3,332	370	410	163	0	4,275
24	464 Other Structures and Improvements	4,479	19	372	27	0	4,897
25	465 Mains	639,373	32,903	13,284	4,524	(742)	689,342
26	466 Compressor Equipment	96,576	1,158	4,480	1,685	0	103,899
27	467 Measuring and Regulating Equipment	25,945	2,019	1,816	4,761	0	34,541
28	468 Communication Structures and Equipment	546	21	0	280	0	847
29	469 Other Transmission Equipment	0	0	0	0	0	0
30	**TOTAL TRANSMISSION PLANT**	815,482	41,388	22,421	18,898	(742)	897,447
31							
32	470 Land	2,999	44	0	107	0	3,150
33	471 Land Rights	637	17	0	15	0	669
34	472 Structures and Improvements	5,994	437	0	60	0	6,491
35	473 Services	453,061	50,694	0	19,117	(2,021)	520,851
36	474 House Regulators and Meter Installations	121,749	6,854	0	10,071	(317)	138,357
37	475 Mains	604,058	79,342	0	25,967	(2,078)	707,289
38	476 Compressor Equipment						
39							
40	-All Other	229	346	0	0	0	575
41	477 Measuring and Regulating Equipment	49,270	1,019	2	11,074	(325)	61,040
42	478 Meters	145,080	14,266	0	12,488	(526)	171,308
43	479 Other Distribution Equipment	0	0	0	0	0	0
44	**TOTAL DISTRIBUTION PLANT**	1,383,077	153,019	2	78,899	(5,267)	1,609,730

GAS PLANT IN SERVICE
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	Balance 12/31/2002	OH Adjustment	CPCN'S	Projected 2003 Additions	Retirements	Balance 12/31/2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	480 Land	$20,700	185	$0	$5	$0	$20,890
2	481 Land Rights	0	0	0	0	0	0
3	482 Structures and Improvements						
4	- Coastal Facilities	0	0	0	0	0	0
5	-All Other	40,898	683	0	746	(11,824)	30,503
6	483 Office Furniture and Equipment						
7	-Furniture and Equipment	22,144	1,271	(88)	11	(12)	23,326
8	-Computers - Hardware	26,222	195	140	4,869	(4,368)	27,058
9	-Computer Software - Non-Infrastructure	40,242	0	0	1,592	(1,256)	40,578
10	-Computer Software - Infrastructure/Custom	71,390	794	4,528	8,700	(589)	84,823
11							
12							
13	484 Transportation Equipment	433	345	0	0	(31)	747
14							
15	485 Heavy Work Equipment	153	112	0	0	0	265
16	486 Tools and Work Equipment	23,246	513	0	233	(195)	23,797
17	487 Equipment on Customer's Premises	1,644	169	0	0	0	1,813
18	488 Communication Equipment	12,927	445	20	1,587	(267)	14,712
19	489 Other General Equipment						
20	-Stores Material, Capital	0	0	0	0	0	0
21	-All Other	0	2	0	0	0	2
22							
23	**TOTAL GENERAL EQUIPMENT**	259,999	4,714	4,600	17,743	(18,542)	268,514
24							
25	492 Gas Plant Held for Future Use	0	0	0	0	0	0
26	496 Unclassified Plant	0	0	0	0	0	0
27	497 Allowance for Funds Used						
28	During Construction	0	0	0	0	0	0
29	498 Overhead Charged To Construction	200,003	(200,003)	0	0	0	0
30	499 Plant Suspense	0	0	0	0	0	0
31							
32	**TOTAL UNCLASSIFIED PLANT**	200,003	(200,003)	0	0	0	0
33							
34	**TOTAL CAPITAL**	$2,696,795	$0	$27,023	$117,677	($24,551)	$2,816,944

TERASEN GAS INC..

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars (1)		Balance 12/31/2002 (2)	Projected 2003 Additions (3)	Projected 2003 Retirements (4)	Balance 12/31/2003 (5)
1	DSEP/GEAP	211-06	$12,671	$0	$0	$12,671
2						
3	NGV Conversion Grants	211-07	0	0	0	0
4						
5	NGV Station Grants	211-08	0	0	0	0
6						
7	Furniture & Equipment	211-10	111	0	0	111
8						
9	Software Tax Savings - Non-Infrastructure	211-11	14,059	937	(750)	14,246
10	- Infrastructure/Custom	211-1	36,326	4,012	(245)	40,093
11	Service Installation Fee	211-	14,264	1,840	0	16,104
12						
13	Other	211-00 to 05	56,858	2,583	0	59,441
14	(Main Extensions, Excess Service Line Charges, etc.)					
15	TOTAL		134,289	9,372	(995)	142,666
16						
17						
18						
19	Amortization	211-15 to 22				
20						
21	- Software Tax Savings - Non-Infrastructure		(4,918)	(1,757)	750	(5,925)
22	- Infrastructure/Custom		(11,957)	(4,541)	245	(16,253)
23	- Other		(15,889)	(1,849)	0	(17,738)
24						
25						
26	Total Amortization		(32,764)	(8,147)	995	(39,916)
27						
28	NET		$101,525	$1,225	$0	$102,750

TERASEN GAS INC..

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	Account	Balance 12/31/2002	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2003	Mid-Year Average 2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($4,077)	($3,600)	3,098	($502)	$863	$0	($3,716)	($3,897)
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	31	0	0	0	(23)	0	8	20
5										
6	NGV Conversion Grants	#17977	159	190	(69)	121	(35)	0	245	202
7										
8	2003 Revenue Requirement	#17989	180	229	(84)	145	(53)	0	272	226
9	2004-2007 Revenue Requirements	#17952	0	250	(91)	159	0	0	159	80
10										
11	Demand Side Management	#17916	1,858	1,500	(548)	952	(804)	0	2,006	1,932
12	Demand Side Management DRIA	#17961	(262)	0	0	0	87	0	(175)	(219)
13										
14	Property Tax Deferral	#17915	(318)	(2,050)	748	(1,302)	106	0	(1,514)	(916)
15										
16	G.C.R.A.*	#17926	38,149	(5,986)	2,185	(3,801)	0	(34,348)	0	19,075
17	G.C.R.A. Interest	#17973	821	(197)	(337)	(534)	0	(704)	(417)	202
18										
19	RSAM*	#17927	27,727	38,581	(14,082)	24,499	0	(7,535)	44,691	36,209
20	RSAM Interest	#17999	0	360	(131)	229	0	0	229	115
21										
22	Revelstoke Propane Cost	#27902	22	(200)	73	(127)	0	0	(105)	(42)
23										
24	B.C. Hydro Service Agreement Costs	#17963	943	0	0	0	(472)	0	471	707
25										
26	Coastal Facilities									
27	- Relocation	#17951	1,159	0	0	0	(477)	0	682	921
28	- Extraordinary Plant Loss - Lochburn	#17998	102	11	0	11	(20)	0	93	98
29	- Fraser Valley NBV Amortization	#17996	632	0	0	0	(213)	0	419	526
30	- Noncapital Finance Costs	#17984	736	0	0	0	(368)	0	368	552
31										
32	Note: Line 16 and Line 19 are G.C.R.A. and RSAM actual activities and balances.									

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	Account	Balance 12/31/2002	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2003	Mid-Year Average 2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
33	ABC T Project Requirements Phase	#17918	60	0	0	0	(30)	0	30	45
34										
35	Burner Tip Service	#17972	(100)	(8)	3	(5)	100	0	(5)	(53)
36										
37	Earnings Sharing Mechanism	#17982	415	0	0	0	(294)	(121)	0	208
38										
39	Salmon Arm Reinforcement	#17990	68	0	0	0	(68)	0	0	34
40										
41	NGV Compression Equip. Recovery	#17992	1,491	0	0	0	(213)	0	1,278	1,385
42										
43	2001 Rate Design	#17974	230	0	0	0	(115)	0	115	173
44										
45	Overheads Change - Income Tax Refund	#17995	(692)	0	0	0	138	0	(554)	(623)
46	CIAOC Software Tax Savings/OH Change	#17995	(4,039)	0	0	0	808	0	(3,231)	(3,635)
47										
48	Other Post Employment Benefits	#17991/93	(4,941)	(5,701)	2,081	(3,620)	0	0	(8,561)	(6,751)
49										
50	Deferred 2000 SCP Cost of Service	#17997	318	0	0	0	(64)	0	254	286
51										
52	SCP Net Mitigation Revenues	#17912	(3,857)	916	(334)	582	771	0	(2,504)	(3,181)
53	SCP West to East Transmission	#17913	1,771	39	(14)	25	(354)	0	1,442	1,607
54	SCP PG&E Contract Cancellation	#17936	0	1,400	(511)	889	0	0	889	445
55										
56										
57	CCT Deferral	#17924	(664)	0	0	0	133	0	(531)	(598)
58	CCT Assessment	#17929	157	342	(125)	217	0	0	374	266
59										
60										
61	Total Deferred Charges for Rate Base		$58,079	$26,076	($8,138)	$17,938	($597)	($42,708)	$32,712	$45,399

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Account	Balance 12/31/2002	Annual Depreciation Rate %	Provision 2003 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2002	Accumulated 12/31/2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	44	45
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	319	326
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	43	44
6	402-00 Utility Plant Acquisition Adjustment	685	1.00%	7	0	0	0	0	24	31
7	402-00 Other Intangible Plant - Lease	85	Lease	1	0	0	0	0	89	90
8		1,706		17	0	0	0	0	519	536
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	432 Manufact'd Gas - Struct. & Improvements									
22	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
23	- Masonry Buildings	431	1.50%	6	0	0	0	0	57	63
24	433 Manufacturing Equipment	139	3.00%	4	0	0	0	0	22	26
25	434 Gas Holders - Manufacturing	353	2.00%	7	0	0	0	0	123	130
26	436 Compressor Equipment	53	3.00%	1	0	0	0	0	12	13
27	437 Measuring & Regulating	295	3.00%	9	0	0	0	0	87	96
28	442-00 Structures and Improvements	3,063	4.00%	123	0	0	0	0	1,091	1,214
29	443-00 Gas Holders Storage	15,714	4.00%	629	0	0	0	0	5,402	6,031
30	449-00 Local Storage Equipment	16,371	4.00%	655	0	0	0	0	5,180	5,835
31		36,419		1,434	0	0	0	0	11,974	13,408

TERASEN GAS INC..
PROJECTION
DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Account	Balance 12/31/2002	Annual Depreciation Rate %	Provision 2003 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2002	Accumulated 12/31/2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461-Land Rights - Byron Creek	$16	5.00%	$1	$0	$0	$0	$0	$13	$14
3	460-00 / 461-00 Land / Land Rights	33,269	0.00%	0	0	0	0	0	232	232
4	462-00 Structures and Improvements - Compressor Stn	14,005	3.00%	420	0	0	0	0	2,222	2,642
5	463-00 Measuring & Regulating	3,742	3.00%	112	0	0	0	0	572	684
6	464-00 Other Structures - Frame Buildings	4,851	3.00%	146	0	0	0	0	219	365
7	465-00 Mains & Crossings	651,772	2.00%	13,035	0	(742)	0	0	95,215	107,508
8	465-00 Mains & Crossings - Byron Creek	885	5.00%	44	0	0	0	0	565	609
9	466-00 Compressor Equipment	101,056	3.00%	3,032	0	0	0	0	13,235	16,267
10	467-00 Measuring & Regulating	22,133	3.00%	664	0	0	0	0	3,433	4,097
11	467-10 Telemetering	5,628	10.00%	563	0	0	0	0	3,368	3,931
12	468-00 Communications Structures & Equip.	546	10.00%	55	0	0	0	0	230	285
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		837,903		18,072	0	(742)	0	0	119,304	136,634
15										
16	**DISTRIBUTION PLANT**									
17	471-Land Rights - Byron Creek	3,000	0.00%	0	0	0	0	0	4	4
18	472-00 Structures & Improvements									
19	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
20	-Frame Buildings	5,992	3.00%	180	0	0	0	0	1,222	1,402
21	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
22	-Byron Creek	2	3.00%	0	0	0	0	0	2	2
23	473-00 Services	453,061	2.00%	9,061	0	(2,021)	0	0	61,273	68,313
24	474-00 House Regulator & Meter Installation	121,749	3.00%	3,652	0	(317)	0	0	19,669	23,004
25	475-00 Mains	604,058	2.00%	12,081	0	(2,078)	0	0	141,839	151,842
26	476-00 Compressed Natural Gas									
27										
28	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
29	-All Other	229	6.67%	15	0	0	0	0	127	142
30	477-00 Measuring & Regulating	44,058	3.00%	1,322	0	(325)	0	0	4,154	5,151
31	477-10 Telemetering	5,019	10.00%	502	0	0	0	0	2,806	3,308
32	477-00 Measuring & Regulating - Byron Creek	195	5.00%	10	0	0	0	0	(1)	9
33	478 Meters	145,080	3.00%	4,352	0	(526)	0	0	24,437	28,263
34	479 Other Distribution Equipment	0	4.00%	0	0	0	0	0	0	0
35		1,382,443		31,175	0	(5,267)	0	0	255,532	281,440

TERASEN GAS INC..
PROJECTION
DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Account	Balance 12/31/2002	Annual Depreciation Rate %	Provision 2003 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2002	Accumulated 12/31/2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	480-00 Land	20,700	0%	$0	$0	$0	$0	$0	$0	$0
3	482-00 Structures & Improvements									
4	-Leasehold Alterations	$12,795	Term - Lease	$875	$0	($11,824)	$0	$0	$11,608	$659
5	-Masonry Buildings	23,551	1.50%	353	0	0	0	0	1,695	2,048
6	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,675)	(3,538)
7	- Coastal Facilities	0	1.5%	0	0	0	0	0	0	0
8	483-00 Office Furniture & Equipment									
9	-Furniture & Equipment	22,056	5.00%	1,103	0	(12)	0	0	7,191	8,282
10	-Computers - Hardware	26,362	20.00%	5,272	0	(4,368)	0	0	17,541	18,445
11										
12	-Computer Software - Non-Infrastructure	40,242	12.50%	5,030	0	(1,256)	0	0	14,036	17,810
13	-Computer Software - Infrastructure/Custom	75,918	12.50%	9,490	0	(589)	0	0	27,586	36,487
14										
15	484-00 Transportation Equipment	433	15.00%	65	0	(31)	0	0	2,624	2,658
16	485-00 Maintenance & Repair Equipment	153	5.00%	8	0	0	0	0	(364)	(356)
17	486-00 Tools & Work Equipment	23,246	5.00%	1,162	0	(195)	0	0	7,522	8,489
18	487-00 Equipment on Customers' Premises	1,061	5.00%	53	0	0	0	0	531	584
19	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
20	487-XX - VRA Compressor Installation Cost	583	33.33%	194	0	0	0	0	288	482
21	488-00 Communication - Structures & Equip.	8,451	5.00%	423	0	(267)	0	0	2,212	2,368
22	488-00 Communication - Radios	4,496	10.00%	450	0	0	0	0	2,392	2,842
23	489-00 Other General Equipment	0	5.00%	0	0	0	0	0	0	0
24		264,599		24,615	0	(18,542)	0	0	91,187	97,260
25	**UNCLASSIFIED PLANT**									
26	498-00 O&M Expense Charged to Construction	200,003	2.20%	4,400	0	0	0	0	14,219	18,619
27										
28	TOTAL	$2,723,073		$79,713	$0	($24,551)	$0	$0	$492,735	$547,897

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
FIVE YEAR CAPITAL PROJECT PLAN

In response to the B.C. Utilities Commission requirement for the 2003 Annual Review, the Five Year Major Capital Project Plan for Terasen Gas is presented below in the requested format.

Major Capital Projects are defined in this plan as those discrete projects that are in excess of $1.0 million (excluding AFUDC).

1. PEAK LOAD PROJECTIONS

Terasen Gas operates two types of gas delivery systems delineated by operating pressure:

- Transmission systems operating in pressures in excess of 2,069 kPa and
- Distribution systems operating in pressures below 2,069 kPa.

The Terasen Gas transmission pressure system is divided into three subsets:

- the Coastal Transmission system
- the Interior Transmission system and
- the Transmission Pressure laterals from the Duke Energy Gas Transmission and TransCanada Pipeline systems.

The Terasen Gas distribution pressure system is divided into three subsets based on pressure range:

- the Intermediate Pressure systems operating between 690 - 2,069 kPa
- the Distribution Pressure systems operating between 114 - 690 kPa and
- the Low Pressure systems operating below 114 kPa.

The distribution pressure system is made up of approximately 15 Intermediate Pressure systems and 70 Distribution and Low Pressure systems.

Loads from the lower pressure distribution systems are rolled-up and are ultimately captured in the peak load projections for the transmission pressure system.

The following table shows the peak load projections (forecast design loads) used in this Five Year Major Capital Project Plan 2004-2008 for the areas of capacity shortfalls.

Peak Load Projections (Forecast Design Loads) 2004 - 2008

Coastal Transmission System

		2004	2005	2006	2007	2008
10^3m^3/hr	Peak Hour	1,884	1,896	1,925	1,956	1,988

Interior Transmission System

		2004	2005	2006	2007	2008
10^3m^3/day	Peak Day	8,175	8,319	8,477	8,648	8,813

Note that the Peak Load Projection for the Interior Transmission System is stated on a daily rather than hourly basis to reflect the significant role played by the line pack for the Interior.

2. AREAS OF CAPACITY SHORTFALL

2.1 Coastal Transmission System

Based on the Coastal Transmission System peak load projections (forecast design loads) for 2004-2008 one major project has been identified:

Nichol/Coquitlam Loop

The decision by B.C. Hydro to increase its contract demand under the Burrard Bypass Agreement drives the need to accelerate the timing of looping between Nichol and Coquitlam Stations in the Lower Mainland.

This circumstance was contemplated in the discussions regarding the Bypass Agreement and Langley Compressor Station approvals. Increased capacity requirements of Burrard Thermal and of Terasen Gas (Vancouver Island) Inc. (formerly Centra Gas BC) will require pipeline expansion, but the long-term implications surrounding the Georgia Strait Crossing project create uncertainty regarding the actual amount of capacity required. Further complicating the picture is the uncertain prospect for independent power generation at greenhouse operations in Delta and general growth in the greenhouse industry. While immediate implications of greenhouse growth only affect the distribution system in the Ladner area, long-term implications may influence the need and timing of the Nichol/Coquitlam Loop.

This project is currently planned to be constructed in two parts:

- 2005 - Nichol Station to Port Mann, 4.4 km of 762mm O.D. pipeline, with an estimated cost of $12.36 million (excluding AFUDC) and expected to be in service in 2005.
- 2007 – Cape Horn to Coquitlam, 5.2 km of 762mm O.D. pipeline, with an estimated cost of $10.83 million (excluding AFUDC) and expected to be in service in 2007.

This project is expected to be the subject of a CPCN application.

2.2 Interior Transmission System

Based on the Interior Transmission System peak load projections (forecast design loads) for 2004-2008 the following major project has been identified:

Okanagan Reinforcement (Naramata Loop and Kitchener B Compressor Station Projects)

Growth within the Thompson-Okanagan area will necessitate reinforcement of the transmission facilities serving the region. Terasen Gas has undertaken a system infrastructure review that concluded that the solution is a program of phased looping of the pipeline between Penticton and Kelowna.

This project is currently planned to be constructed in two parts:

- 2007 – Naramata Loop. The first phase of this program consists of 24 km of 508mm O.D. pipeline loop extending from the north end of the SONG pipeline at Ellis Creek Station in Penticton to north of Naramata. The estimated cost of this project is $31.99 million (excluding AFUDC) and is expected to be in service in 2007.
- 2007 – Kitchener B Compressor Station. In addition to the Naramata Loop, increased compression power will also be required at the Kitchener B Compressor Station. This will be accomplished through the addition of a third compressor unit at this station at an estimated cost of $19.39 million (excluding AFUDC) and is expected to be in service in 2007.

This project is expected to be the subject of a CPCN application.

2.3 Transmission Pressure Laterals

Based on the Transmission Pressure Laterals peak load projections (forecast design loads) for 2004-2008, there are no major projects that have been identified.

2.4 Intermediate Pressure Systems

Based on the Intermediate Pressure systems peak load projections (forecast design loads) for 2004-2008 the following major projects have been identified:

Serpentine to Nicomekl, Surrey

This project is currently planned to be constructed in 2004. It consists of 2 km of 323mm O.D. pipeline operating at 1,900 kPa. The estimated cost of this project is $1.30 million (excluding AFUDC) and is expected to be in service in 2004.

Riverside Road, Abbotsford

This project is currently planned to be constructed in 2004. It consists of a 1.6 km loop of 323mm O.D. pipeline operating at 1,900 kPa. The estimated cost of this project is $1.10 million (excluding AFUDC) and is expected to be in service in 2004.

<u>36th Avenue, Delta</u>

This project is currently planned to be constructed in 2006. It consists of a 1.75 km loop of 323mm O.D. pipeline operating at 1,200 kPa. The estimated cost of this project is $1.20 million (excluding AFUDC) and is expected to be in service in 2006.

<u>Goudy Road and 36th Avenue, Delta</u>

This project is currently planned to be constructed in 2007. It consists of a 1.5 km loop of 323mm O.D. pipeline operating at 1,200 kPa. The estimated cost of this project is $1.00 million (excluding AFUDC) and is expected to be in service in 2007.

<u>Fraser Loop, Vancouver</u>

This project is currently planned to be constructed in 2008. It consists of 2.7 km of 762mm O.D. pipeline operating at 1,200 kPa which creates a loop from Fraser Gate Station to the District Station at 50th and Vivian. The estimated cost of this project is $5.00 million (excluding AFUDC) and is expected to be in service in 2008. This project is expected to be the subject of a CPCN application.

2.5 Distribution Pressure Systems

Based on the Distribution Pressure systems peak load projections (forecast design loads) for 2004-2008, there are no major projects that have been identified.

2.6 Low Pressure Systems

Based on the Low Pressure systems peak load projections (forecast design loads) for 2004-2008, there are no major projects that have been identified.

3. PROJECTS FOR SYSTEM MODIFICATION OR EXPANSION

3.1 Acquisition of Right-Of-Way Nordel to Tilbury, Delta

Acquisition of right-of-way adjacent to the two transmission pipelines in Burns Bog, Delta that transports the majority of the natural gas supply to Vancouver, Richmond and Burnaby has been underway for a period of two years. This safety buffer is required to mitigate damage occurring to the pipelines caused by soil failure relating to the adjacent land fill operations and property developments.

2004 is the final year of the phased land purchase. The estimated cost of the final major land acquisition project is $1.53 million (excluding AFUDC). Acquisition is expected to be completed in 2004.

3.2 Secondary Containment

To comply with Provincial and Federal legislation all storage containers that hold a volume greater than 205 litres of flammable or combustible liquid require secondary containment facilities.

In 2002 Terasen Gas embarked on a five year program to construct secondary containment facilities. The total estimated cost of this project is $9.20 million (excluding AFUDC) and is expected to be complete in 2006. The remaining expenditures are forecasted at: $1.90 million in 2004; $2.10 million in 2005 and $2.39 million in 2006 (all estimates exclude AFUDC).

3.3 Automated Mapping/Facilities Management (AM/FM) Geographical Information System (GIS) for Transmission Asset Management

This project began in 2003 and is an implementation of an integrated AM/FM GIS for the transmission plant asset information for Terasen Gas. An AM/FM GIS implementation for Intermediate and Distribution pressure plant asset information was previously completed in 2001. The total estimated cost of this project is $1.90 million (excluding AFUDC) and is expected to be complete in 2005. The remaining expenditures are forecasted at: $1.20 million in 2004 and $0.30 million in 2005 (all estimates exclude AFUDC).

3.4 SAP Core Application Upgrade

SAP is the enterprise application that supports business processes for: Operate and Maintain; Order Fulfillment and back-office functions. Vendor support of the current version of the SAP application (R3 v4.7) expires in Q1 2006. An upgrade to the subsequent application, currently referred to as “SAP Enterprise” is therefore required to be in place by Q1 2006. The total estimated cost of this project is $2.50 million (excluding AFUDC). Implementation is expected to begin in 2005 and completed in 2006.

3.5 Air Turbine Meter Testing Facility Enhancement

Imminent regulatory and market demand necessitates enhancements to be made to the existing low pressure air turbine meter testing facility in Penticton. These enhancements will facilitate more accurate calibration for meters that measure gas at pressures up to 900 kPa. This project is currently pending approval based on completion of a proof of concept phase. The total estimated cost of this project is $1.90 million (excluding AFUDC). Implementation is expected to commence in 2003 and complete in 2004.

3.6 Fraser River Crossing, Vancouver

Recent analysis of the seismic performance of the 762mm and 609mm O.D. transmission pipelines crossing the Fraser River, between Tilbury and Vancouver, indicate that the seismic capacity of both pipelines may be over estimated. Based on this information the only effective means of mitigation would be to replace both lines using horizontal directional drilling. A seismic study to validate existing analysis has been planned in 2003/2004.

If the results of the 2003/2004 study indicate that these pipelines are required to be replaced, the project is expected to be the subject of a CPCN application. At this point, it is expected that replacement of the two pipelines would commence in late 2004 or early 2005.

4. COST PROJECTIONS FOR REGULAR CAPITAL AND CPCN'S

4.1 Cost Projections for Regular Capital

The following table identifies the cost projections for regular capital expenditures in 2004 – 2008.

Cost Projections for Regular Capital Expenditures 2004 - 2008

Customer Driven Capital	**2004**	**2005**	**2006**	**2007**	**2008**
Mains	4,796	4,914	5,140	5,372	5,595
Services	8,934	9,350	9,664	10,097	10,402
Meters - Customer Additions	2,539	2,581	2,706	2,755	2,833
	16,269	**16,845**	**17,510**	**18,224**	**18,830**
Other Regular Capital	**2004**	**2005**	**2006**	**2007**	**2008**
Meters - Replacement	14,543	14,949	15,282	15,645	16,111
System Integrity & Reliability					
Transmission Plant	12,049	5,979	5,121	5,932	6,051
Distribution Plant	13,015	11,331	16,856	8,999	9,179
Other Capital					
Non - IT	12,000	11,444	11,692	11,946	12,222
IT Projects	12,195	14,183	15,475	15,825	16,180
	63,802	**57,886**	**64,426**	**58,347**	**59,743**
Total Regular Capital	**80,071**	**74,731**	**81,936**	**76,571**	**78,573**

Note: All estimates exclude AFUDC.

The forecast expenditures for 2004 differ from those allowed per the formula-based capital expenditures used to establish rates for 2004. The forecast reflects the expectations that the Company will realize efficiencies in both customer driven and other capital through process improvements and other initiatives that are contemplated or currently being implemented.

4.2 Cost Projections for CPCNs

The following table identifies the cost projections for major capital projects subject to CPCN applications for 2004 – 2008:

Cost Projections for Major Capital Projects Subject to CPCN Applications 2004 - 2008

CPCN Applications		**2004**	**2005**	**2006**	**2007**	**2008**
4.2.1	TPIP	2,777	3,788	-	-	-
4.2.2	Nichol to Coquitlam Loop	-	12,360	-	10,826	-
4.2.3	Okanagan Reinforcement					
	Naramata Loop	-	-	-	31,991	-
	Kitchener B Compressor	-	-	-	19,389	-
4.2.4	Fraser Loop	-	-	-	-	5,000
Total CPCN Applications		**2,777**	**16,148**	**-**	**62,206**	**5,000**

Note: All project estimates exlude AFUDC

Transmission Pipeline Integrity Plan

The Transmission Integrity Management Plan (TPIP) is part of an overall transmission system integrity management program that was developed to ensure that the transmission pipelines provide continued safe and reliable service.

The major components of the TPIP are:

- retrofits of the existing pipeline systems to allow the passage of In-Line Inspection tools which detect corrosion, dents and other anomalies
- repair programs
- rehabilitation programs
- development of a corrosion growth model that drives inspection and remediation

Since, 2001 CPCN applications have been submitted annually based on the general program and rehabilitation costs in the year of application and retrofit and tool run costs for the subsequent year.

Forecasted capital expenditures that are subject to CPCN applications in 2004 – 2008 are as follows:

- 2004 – Continued Coastal Transmission System retrofit to allow the efficient use of in-line inspection tools. The estimated cost is $2.78 million (excluding AFUDC).
- 2005 – Continued Coastal Transmission System retrofit to allow the efficient use of in-line inspection tools. The estimated cost is $3.79 million (excluding AFUDC).

Subsequent expenditure to complete the TPIP, which is forecasted in 2008, will be funded through the Company's other regular capital expenditures and operating and maintenance expenditures.

Coastal Transmission System - Nichol/Coquitlam Loop

As detailed in Section 2.1.1 Areas of Capacity Shortfall (above), forecasted capital expenditure for this project that is subject to a CPCN application in 2004 – 2008 is as follows:

- 2005 - Nichol Station to Port Mann, 4.4 km of 762mm O.D. pipeline, with an estimated cost of $12.36 million (excluding AFUDC) and expected to be in service in 2005.
- 2007 – Cape Horn to Coquitlam, 5.2 km of 762mm O.D. pipeline, with an estimated cost of $10.83 million (excluding AFUDC) and expected to be in service in 2007.

Interior Transmission System - Okanagan Reinforcement (Naramata Loop and Kitchener B Compressor Station Projects)

As detailed in Section 2.2.1 Areas of Capacity Shortfall (above), forecasted capital expenditure for this project that is subject to a CPCN application in 2004 – 2008 is as follows:

- 2007 – Naramata Loop. The first phase of this program consists of 24 km of 508mm O.D. pipeline loop extending from the north end of the SONG pipeline at Ellis Creek Station in Penticton to north of Naramata. The estimated cost of this project is $31.99 million (excluding AFUDC) and is expected to be in service in 2007.
- 2007 – Kitchener B Compressor Station. In addition to the Naramata Loop, increased compression power will also be required at the Kitchener B Compressor Station. This will be accomplished through the addition of a third compressor unit at this station at an estimated cost of $19.39 million (excluding AFUDC) and is expected to be in service in 2007.

Intermediate Pressure System - Fraser Loop, Vancouver

As detailed in Section 2.4.5 Areas of Capacity Shortfall (above), forecasted capital expenditure for this project that is subject to a CPCN application in 2004 – 2008 is as follows:

- 2008 – Fraser Loop. This project consists of 2.7 km of 762mm O.D. pipeline operating at 1,200 kPa which creates a loop from Fraser Gate Station to the District Station at 50th and Vivian. The estimated cost of this project is $5.00 million (excluding AFUDC) and is expected to be in service in 2008.

5. SCHEDULING OF PROJECTS

The following table shows the scheduling and cost projections of the major capital projects by year from 2004 - 2008.

Scheduling and Cost Projections of Major Capital Projects 2004 - 2008

Other Regular Capital
Transmission and Distribution Plant

		2004	2005	2006	2007	2008
2.4.1	Serpentine to Nikomekl	1,300	-	-	-	-
2.4.2	Riverside Road, Abbotsford	1,100	-	-	-	-
3.1	Acquisition of ROW Nordel to Tilbury, Delta	1,530	-	-	-	-
3.2	Secondary Containment	1,900	2,100	2,389	-	-
2.4.3	36th Avenue, Delta	-	-	1,200	-	-
2.4.4	Goudy Road and 36th Avenue, Delta	-	-	-	1,000	-
		5,830	2,100	3,589	1,000	-

Other Regular Capital
Non-IT and IT

		2004	2005	2006	2007	2008
3.5	Air Meter Testing Facility Enhancement	1,440	-	-	-	-
3.3	AM/FM GIS for Transmission	1,200	300	-	-	-
3.4	SAP Core Application Upgrade	-	2,000	500	-	-
		2,640	2,300	500	-	-

Other Regular Capital
CPCNs & Deferrals

		2004	2005	2006	2007	2008
4.2.1	Transmission Pipeline Integrity Plan (TPIP)	2,777	3,788	-	-	-
2.1.1	Nichol to Coquitlam Loop					
	Nichol to Port Mann	-	12,360	-	-	-
	Cape Horn to Coquitlam	-	-	-	10,826	-
4.2.3	Okanagan Reinforcement					
	Naramata Loop	-	-	-	31,991	-
	Kitchener B Compressor	-	-	-	19,389	-
4.2.4	Fraser Loop	-	-	-	-	5,000
		2,777	16,148	-	62,206	5,000

Note: All project estimates exlude AFUDC

6. CPCNS THAT MAY BE NEEDED IN FUTURE YEARS

The Five Year Major Capital Project Plan is updated on an annual basis. Projections for projects that fall outside of the five year timeframe are not subject to detailed project estimating due to the uncertainties in projecting the economic and business environments, and population growth.

Currently there are no projects that have been identified as being subject to CPCN applications outside of the 2004 – 2008 Capital planning timeframe.

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
SERVICE QUALITY INDICATORS

1 INTRODUCTION

Approvals for performance based rates and multi-year revenue requirements typically include mechanisms for ensuring the regulated utility maintains the quality of its monopoly services. This is because, after the performance based rates and multi-year revenue requirements have been established, a utility may have an incentive to reduce costs through lowering the quality of its services in favour of achieving financial objectives.

The 2004-2007 Negotiated Settlement agreed on a Service Quality Assurance Mechanism that will serve to balance the financial incentives during 2004-2007. Several aspects of service will be tracked under the Service Quality Assurance Mechanism and results will be compared on an annual basis against benchmarks. Current performance levels for these aspects of service are included on a preliminary basis in this 2003 Annual Review.

2 COMPONENTS OF THE SERVICE QUALITY ASSURANCE MECHANISM

The Service Quality Assurance Mechanism includes four components:

1. A set of eleven service quality indicators;
2. Benchmark targets for eight of the indicators;
3. Two directional indicators; and
4. A process for reviewing Terasen Gas performance.

Service Quality Indicators and Benchmarks

<u>History of Service Quality Indicators</u>

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

1. Response time to site for emergency calls (only for the Coastal region).
2. Percent of responses within 30 seconds by a person at a call centre (only for the Coastal region).
3. Leaks per kilometer of Distribution mains due to system deterioration.

4. Transmission system annual reportable incidents.

5. Number of third party distribution system damage incidents per 1000 housing starts.

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

Choice of Benchmarks

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

Service Quality Indicators and Benchmarks

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

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

This indicator is the average length of time after notification for a qualified utility representative to arrive on the scene of the emergency (i.e. a pulled main or a situation where gas is blowing) at any location on the Terasen Gas system both during and after working hours. The benchmark is set at the average for the past three years: 21.1 minutes. Information for the Interior System has become available only recently, but this information has been researched back to 2000 in order to set the benchmark.

Year	Response Time Dispatched to Site for Emergency Calls
2003 (Jan - Sept)	22.9 minutes
2002	20.5 minutes
2001	21.7 minutes
2000	21.2 minutes
Benchmark	21.1 minutes

2 Speed of Answer - Emergency
(Percent of responses by a Person within 30 seconds - Emergency Calls)

The amount of time it takes for the telephone to be answered is a common service quality indicator. Emergency Call Handling for the Lower Mainland Call Centre was a Service Quality Indicator from 1998 to 2002. The introduction of the Interior call centre allowed Terasen Gas to track the Percent of Responses by a Person within 30 seconds for Emergency Calls for both the Coast and Interior since 2000. The benchmark of 95.0% is based on the performance clause in the contract with CustomerWorks. Note the benchmark is an improvement over the three-year historical average.

Year	Percent of responses by a Person within 30 seconds for Emergency Calls
2003 (Jan - Sept)	96.7%
2002	95.9%
2001	91.2%
2000	90.3%
Benchmark	95.0%

3 Speed of Answer – Non Emergency
(Percent responses by a Person within 30 seconds - Non-Emergency Calls)

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

Year	Percent of responses by a Person within 30 seconds for Non Emergency Calls
2003 (Jan - Sept)	77.3%
2002	73.8%
2001	79.0%
2000	72.0%
Benchmark	75.0%

4 Transmission System Integrity (Transmission System Annual Reportable Incidents)

This indicator is presently tracked manually and this is expected to continue, as it covers several different kinds of incidents that are reported to government. It is noted that some government agencies have changed their interpretation of a reportable incident and this is likely to increase the number of incidents reported under this SQI during the 2004-2007 PBR period. Also, the Transmission Pipeline Integrity Plans are escalating the level of transmission activity beyond historic levels and this may also increase the number of incidents reported under this SQI during the 2004-2007 PBR period.

Year	Transmission System Annual Reportable Incidents
2003 (Jan - Sept)	3
2002	1
2001	2
2000	3
Benchmark	2

5a Residential & Commercial Customer Billing Activity (Percent of Customer Bills Produced meeting Activity Criteria)

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

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

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

Year	Percent of Customer Bills Produced meeting Activity Criteria
2003 (Jan - Sept)	2.67
Benchmark	5.0

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

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

Year	Percent of Industrial Customer Bills Accurate
2003 (Jan - Sept)	99.9%
Benchmark	99.5%

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

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

Year	Percent of Appointments Met for Meter Exchange
2003 (Jan - Sept)	92.6%
2002	92.2%
Benchmark	92.2%

7 Industrial Meter Measurement (Industrial Meter Measurement First Report under 10%)

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

Year	Industrial Meter Measurement First Report under 10%
2003 (Jan - Sept)	97.9%
Benchmark	90.0%

8 Residential & Commercial Customer Satisfaction (Independent Customer Satisfaction Survey)

This indicator is new for the 2004-2007 PBR. This service quality indicator tracks customer satisfaction using three surveys. A residential survey is conducted quarterly, while a large commercial survey and a builder/developer survey are conducted annually. In order to arrive at the Service Quality Indicator for the Independent Customer Satisfaction Survey, these three surveys are weighted as follows: 80% Residential, 10% Commercial and 10% Builder/Developer. High gas cost volatility and other events beyond the control of Terasen Gas can influence this SQI. No benchmark target has been established but the results will be compared to prior years' experience and trends assessed, recognizing the impact of uncontrollable events.

Year	Independent Customer Satisfaction Survey
2003 (Jan - Sept)	74.1%
Benchmark	To be compared to historic trends

9 Residential & Commercial Customer Satisfaction (Number of Customer Complaints to BCUC)

This service quality indicator is new for the 2004-2007 PBR. This indicator tracks the number of customer complaints submitted to the BCUC that the Commission then requests, either by Commission Letter or by a Complaint/Inquiry Record, that Terasen Gas provide a written response. Historical information is only available beginning in 2003. High gas cost volatility and other events beyond the control of Terasen Gas can influence the number of complaints to the BCUC, so it will be compared to available history recognizing the impact of uncontrollable events.

Year	Number of Customer Complaints to BCUC
2003 (Jan - Sept)	56
Benchmark	To be compared to historic trends

Since repatriating the Lower Mainland customers in July of 2002, CustomerWorks has recorded approximately 11,500 customer inquiries/complaints, an average of 770 per month. The majority of customer issues was addressed during the calls and required no follow-up action. The overall trend in the number of calls has been declining and the nature of the concern has shifted. In the first six months after repatriation, the majority of inquiries/complaints related to a policy decision to not accept payment by credit card, a service that had been offered in the past by BC Hydro, and the change for residential customers from bi-monthly to monthly billing. The implementation of monthly billing necessitated use of estimated readings on a bi-monthly basis.

Since January 1, 2003, the focus of customer complaints has shifted. Terasen Gas is experiencing much higher volumes in all collections-related activities including lock-offs for non-payment of arrears. A condition of reconnection is the requirement to pay a security deposit. In addition, in order to manage the collections process more proactively, CustomerWorks has undertaken an automated outbound calling program to provide early stage reminders to customers. This increased level of collections activity overall, as well as the requirement for many customers to secure their accounts with deposits, has resulted in a large increase in the number of complaints directly related to collections.

Although the number of inquiries/complaints related to the decision not to accept credit card payments has declined, it is still one of the largest volume areas. In response to the continued interest in credit cards, Terasen Gas has just recently implemented an option to customers to pay by credit card based on a "user pay" approach. In this case, the customer utilizing the service absorbs the additional cost associated with the payment method in the form of a fee collected by the payment service provider (rather than Terasen Gas) so the entire customer base does not absorb the cost. Response to date has been good particularly for customers who are experiencing payment problems.

10 Industrial Customer Satisfaction (Number of Prior Period Adjustments)

This service quality indicator is new for the 2004-2007 PBR. This indicator tracks the number of prior period adjustments for Industrial Transportation Service customers. A prior period adjustment is a billing inaccuracy that is identified after a bill has been issued; if this occurs, the bill is adjusted with any necessary corrections. Historical information is only available beginning in 2003. Certain events beyond the control of Terasen Gas can influence this SQI, and data collection has been limited to 2003, so performance will be reviewed against available history, recognizing the impact of uncontrollable events.

Year	Number of Prior Period Adjustments
2003 (Jan - Sept)	17
Benchmark	To be compared to historic trends

Directional Indicators

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

1 Number of Third Party Damages

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

Year	Number of Third Party Damages
2002	1242 incidents
2001	1132 incidents
2000	1284 incidents

2 Leaks per Kilometer of Distribution Mains

The number of leaks detected is to a degree a measure of system integrity. However, the number of leaks detected is also correlated with leak survey frequency and as such, performance incentives to reduce levels could lead to undesirable behaviour i.e. lengthening the frequency between surveys in order to reduce the number of leaks detected. Each year approximately one-fifth of the Distribution System is surveyed for leaks. The number of leaks found will vary, in the short term, more because of the condition of the portion of the system being surveyed in the given year than it will be affected by the quality of the current maintenance program. As such, this statistic as a measure of maintenance effectiveness is only valid over a much longer time horizon; probably 15 to 25 years. Terasen Gas believes it is in customers’ and the Company’s best interest to locate and repair as many existing leaks as reasonably possible, therefore using this measure as an SQI would be somewhat contrary to the real objective. This measure will continue to be tracked and reported as a Directional Indicator, with no benchmark.

Year	Leaks per Kilometer of Distribution Mains
2002	0.0043 (160 leaks)
2001	0.0034 (126 leaks)
2000	0.0046 (170 leaks)

Summary of Service Quality Indicators

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

Summary of Directional Indicators

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

3. REVIEW PROCESS

Service quality results are compared on an annual basis against the benchmark and submitted to the Commission for review. Results for Directional Indicators are also submitted for review. Should the situation occur where the Company fails to meet the service quality benchmarks, a review of Terasen Gas' service policies and procedures would ensue. The review would determine the causes of the decline and ascertain whether the deterioration is due to the Company's actions.

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
DSM STATUS REPORT

1. INTRODUCTION

Under the terms of the 2004 – 2007 Multi-Year PBR Settlement, Terasen Gas is required to submit an annual Demand Side Management ("DSM") Status Report to the Commission as part of the Annual Review process. This is a continuation of past practice under the 1998 – 2001 PBR and through 2003.

This current report is intended to provide an overview of Terasen Gas' DSM activities in 2003 with details pertaining to the progress of individual DSM programs against forecasted targets and objectives for the year. As in prior years, Terasen Gas has offered several types of programs in 2003 most of which are in progress at the time of this writing; therefore, impacts are estimated rather than actual results.

2. OVERVIEW OF DSM PROGRAMS AT TERASEN GAS

In 2003 Terasen Gas has continued efforts to promote natural gas conservation and efficiency to its customers through a combination of awareness, education and incentive programs. Energy conservation and efficiency is also being promoted by a number of other utilities, agencies and industry members: Terasen Gas has attempted, whenever feasible, to partner with others to leverage utility DSM funds.

Proposed programs are subjected to economic cost-benefit tests (most notably a standardized Total Resource Cost test) prior to launch and, when completed, major initiatives are subjected to third party evaluations. The evaluations have proved to be an important tool for process improvement (for example, by indicating delivery problems that should be corrected if the program is to be made available in future) and for determining if the actual impact of the program is sufficient (for example, by measuring actual natural gas savings). In the case of programs where the energy savings measures adopted by the customer are significant, as would be the case if a furnace or boiler is changed to a high efficiency model, Terasen Gas has utilized analysis of customer billing data. Where the energy savings measures might be expected to produce marginal improvements in energy use or efficiency, the use of billing information has proven to be problematic. A recent example has been the attempt to use billing data to discern savings below the 3% level resulting from furnace or boiler tune-ups.
DSM initiatives may also produce benefits for the utility, the customer, and society in general which are not considered as part of the Total Resource Cost test. Of particular interest are the resulting reduced emissions that result from reduced natural gas consumption – contributing to improved local air quality and a reduction in greenhouse gases.

3. PRIOR YEARS INITIATIVES EVALUATION

In its BC Gas Utility Ltd. 2003 Revenue Requirements Decision dated Feb. 4, 2003 the Commission directed BC Gas to conclude its evaluations of existing programs and to file the results with the Commission in time for that information to be available to parties to a Commission proceeding for 2004 rates. On April 24, 2003 BC Gas filed copies of two program evaluations:

- 2001 Residential DSM Campaign Evaluation, R.A. Malatest & Associates Ltd., November, 2002; and,
- BC Gas Commercial DSM Evaluation, R.A. Malatest & Associates Ltd., September, 2002

Copies of these two evaluation reports were subsequently distributed to intervenors as an attachment to an information request response issued May 30, 2003. Two additional evaluation reports have subsequently been completed and are attached here for reference:

- BC Gas Efficient Boiler Program Impact Evaluation, Habart & Associates, June, 2003 (Attachment A), and
- 2002 Residential DSM Heating System Upgrade Program Evaluation, Habart & Associates, October, 2003 (Attachment B)

Efficient Boiler Program

The commercial sector Efficient Boiler Program offered incentives toward the purchase and installation of higher efficiency boilers used in space heating applications. The program was offered from 1994 to 2000 and final incentive payments were made in 2002.

Habart and Associates was engaged to complete an impact evaluation, completed in June of this year. Given the length of time the program was in effect and the modest number of participants (131 in total), the evaluation faced significant challenges in surveying the appropriate decision makers, particularly customers who participated early in the program's lifecycle. While sample sizes were sufficient to determine overall program impacts with certainty, they were not large enough to enable in-depth analysis by customer segment. Notwithstanding, the report's key findings were: the program's rationale was validated, participant satisfaction was generally high and program impacts exceeded original program expectations. The free rider rate was determined to be 18%, and a spill over rate of 58% (i.e. additional savings attributed to the program) was established. The net program savings impact was determined to be 190.34TJ per year.

Utilizing inputs derived from the program evaluation, the program TRC ratio is 4.33 and TRC net benefits are $10,800,000. This very positive result suggests the program should be offered once again.

Evaluation report pertaining to this program: BC Gas Efficient Boiler Program Impact Evaluation, Habart & Associates, June, 2003.

Heating System Tune-up Program

The residential sector Tune-up Program which was offered in both 2001 and 2002 was not offered in 2003. A program evaluation completed in November, 2002 included a billing analysis of participants in the 2001 program but findings were inconclusive. The consultant recommended that the billing analysis portion be attempted again over a longer time period in order to provide more data points. The data for the 2002/2003 heating system has now been extracted and provided to the evaluation consultant and a report is anticipated by the end of November, 2003.

Evaluation report pertaining to this program: 2001 Residential DSM Campaign Evaluation, R.A. Malatest & Associates Ltd., November, 2002.

4. ONGOING INITIATIVES

Destination Conservation

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

The program is organized by the Pacific Resource Conservation Society, a BC based not-for-profit group, and offered to school districts. It features energy conservation curricula and support materials for participating teachers and technical assistance to school facilities management staff. Terasen Gas has contributed a portion of the first year operating costs for the program in a number of school districts in prior years. In 2003, Terasen Gas is supporting the Abbotsford School District with funds for 46 schools.

The DC program includes an energy monitoring component which allows school districts to monitor, analyze and report energy usage information. Utilizing a software program called ‘Utility Manager 4.0 Pro’ coupled with operator training, this package also serves as a useful tool to report weather-normalized energy savings resulting from implementation of energy efficiency measures. DC collects this savings information from each participating school to document program energy savings. Terasen considers this approach to be a cost-effective means of monitoring program impacts. In addition, Terasen Gas understands that DC plans to initiate third party evaluation of savings impact subject to the agreement of participating school districts.

Commercial Energy Utilization Advisory

This program is being offered to larger Rate 3/23 and Rate 5/25 customers by the Terasen Gas Commercial Energy Services group. The offer includes an initial benchmarking consultation and an onsite assessment of natural gas conservation and efficiency opportunities along with recommendations and estimated savings impact. To date there have been 75 completed assessments in 2003, and an expected total of 100 by year end. Of those assessments, 36 customers have begun some or all of the recommended retrofits, saving an average of 660GJs per customer.

Evaluation report pertaining to this program: BC Gas Commercial DSM Evaluation, R.A. Malatest and Associates Ltd., September 2002

Publications

Terasen Gas publishes a number of brochures and pamphlets to encourage residential customers to adopt energy savings measures and practices. In 2003 the Hot Tips booklet, Heart of your Home (a guide to energy efficient heating systems) and a number of data sheets were updated and published. These booklets and data sheets are available to customers on request. Additional conservation tips and advice have been made available through Homeswest Magazine (a Terasen Gas advertiser-supported publication) and through part sponsorship of the Shell Busey Home Discovery radio show. All publications are available online at the utility web site.

Community Participation

Terasen Gas continues to be an active participant in community-based conservation initiatives (for example, the Community Energy Association) and collaborates with the provincial and federal governments to review energy efficiency standards. In 2003 Terasen Gas participated in the provincial Minister's Advisory Group on building energy performance and several task forces.

5. SHORT TERM INITIATIVES

Residential Heating System Upgrade Program

An expanded version of programs offered by Terasen Gas in 2001 and 2003, this limited duration Residential Heating System Upgrade program offers financial incentives to residential customers to replace older furnaces and boilers with high efficiency models. The program was initiated September 1, 2003 and terminates December 15, 2003. It is co-sponsored by Natural Resources Canada (NRCan), BC Hydro Power Smart and Aquila Networks. The total contribution of these three parties toward promotional costs and customer incentives is expected to total approximately $1 million.

Residential customers are offered a $150 utility bill credit towards the purchase of an Energy Star qualified high efficiency furnace or boiler, a $150 credit from NRCan and, in the case of selected furnaces, a $150 credit from the electrical distribution utility and NRCan toward the purchase of a qualifying furnace that has a high efficiency variable speed fan motor. As an alternative to the Terasen Gas/NRCan $300 rebate, customers may elect to borrow up to $4000 at no interest for 2 years from Homeworks Financing provided by the Citizens Bank of Canada. The cost of "buying down" the interest rate of the loan option – expected to cost on average, $300, the same as the rebate option - is being split between Terasen Gas (50%) and NRCan (50%).

Additional supplier-funded incentives ranging from $150 to $600 in value toward the purchase of 15 brands of Energy Star qualified furnaces and boilers are being promoted by Terasen Gas as part of this program. Most of the major suppliers of high efficiency heating systems in BC are participating. These suppliers are also contributing to the direct promotional costs of the campaign and several are conducting their own independent promotional campaigns.

Early results, to mid-October, suggest the response rate for the 2003 program will easily exceed that of the 2002 program (2800) and 2001 program (1450). A complicating factor has been the announcement August 12, 2003 by the Government of Canada of an Energuide for Homes (EGH) Grant Program. The EGH Grant is available to participants in the Terasen Gas upgrade program and, subject to program rules, may provide an additional $200 to $300 net of home audit costs. The upgrading of a standard efficiency, older heating system to an Energy Star model represents one of the most effective energy saving measures under the EGH program. The EGH program became operational October 15, 2003 and NRCan has agreed to "grandfather" heating system installations completed between August 12th, the announcement date, and the October 15th start date.

The program design for the 2003 program, as was the case for the 2002 and 2001 programs, estimates the average annual natural gas savings at 30 GJ per participant – reflecting an improvement from a 60 or 65% AFUE old system to a minimum 85% (for new boilers) or 90% (for new furnaces). The preliminary evaluation report of 2001 program results estimated an impact of 21 GJ per participant – this analysis is currently being confirmed based on more extensive billing data.

Evaluation report pertaining to this program: 2001 Residential DSM Campaign Evaluation, R.A. Malatest & Associates Ltd., November 2002

Residential Fireplace Upgrade

A new pilot program being readied for launch in late November, 2003, the Fireplace Upgrade Program is designed to encourage the purchase and installation of heating-style gas fireplace inserts and free-standing appliances. Originally intended to be initiated in August, 2003, the program has been dependant on the proclamation of a new energy efficiency standard that was delayed until late September. This new standard (based on CSA P.4) requires that all vented gas fireplaces imported into Canada or manufactured in Canada be tested and suitably marked. The process of testing by manufacturers has been initiated and Terasen Gas has participated in a Heating, Refrigeration and Air Conditioning Institute (HRAI) effort to encourage suppliers to voluntarily display the resulting ratings in an Energuide label affixed to product literature.

The availability of this new Energuide label represents the first independent quantification of gas fireplace efficiency: this label is the same as that on new electrical appliances and is well understood by customers. In the Terasen Gas service territory as many as one third of gas fireplaces purchases have been unvented log sets (usually installed in a vented masonry ‘wood’ fireplace) and the resulting heat loss through a fixed-open damper above the log set can exceed the heat output of the burner. The upgrade program will promote fireplaces that have been tested to CSA P.4 and which have product literature exhibiting the Energuide rating.

Similar to the heating system upgrade program, this fireplace upgrade program will include supplier and NRCan participation. Subject to the successful completion of negotiations with NRCan (currently underway), the program will provide for a utility bill credit of up to $200 toward the purchase of an Energuide rated (CSA P.4 tested) unit and will be targeted at consumers who have log sets or who may be intending to purchase log sets or other low efficiency, decorative units. Supplier incentives will be in addition to the utility bill credits and will be administered by suppliers separately.

The program design for this program estimates the average annual natural gas savings at 14 GJ per participant – reflecting the improvement of efficiency over a log set (essentially at 0% efficiency) or other low efficiency inserts or free-standing units. Included in the pilot will be load research and impact savings analysis.

The program dates are subject to completion of discussions with NRCan and participating suppliers, but will not likely extend beyond September, 2004.

6. PROPOSED 2004 INITIATIVES

a. Residential Programs

<u>New Construction Energy Star Heating Systems</u>

This proposed program would target the installation of Energy Star qualified natural gas furnaces and boilers in new construction with an incentive payable to residential builders. Possible partners would include NRCan and appliance suppliers. Additional partners may include BC Hydro and Aquila Networks if a high efficiency furnace fan motor incentive is included.

Energy Star Heating System Upgrade

Similar to the upgrade program offered in 2001-2003, a utility incentive would be paid to residential customers who upgrade their existing low efficiency natural gas furnace or boiler to an Energy Star model. The company plans to examine opportunities to associate the utility program with the federal Energuide for Houses Grant Program which will offer additional incentives to customers who install high efficiency heating systems as part of the Energuide evaluation process. Possible partners would include NRCan, appliance suppliers, and BC Hydro and Aquila Networks if a furnace fan motor incentive is offered.

b. Commercial Programs

Commercial Boiler Upgrade

Similar in nature to the company's Efficient Boiler Program offered between 1994 and 2000, this initiative would provide incentives to purchasers of high efficiency natural gas condensing boilers. Possible partners include NRCan and boiler suppliers.

Commercial Utilization Advisory

The continuation of this program is proposed for 2004 along with an expanded set of web tools to provide commercial customers with comparative natural gas usage information against which their facilities can be benchmarked.

Customized Measure Support

Proposed in a pilot program in 2004 that will provide targeted financial support to individual customers for the installation of natural gas conservation and efficiency measures.

7. SUMMARY OF SAVINGS

Program	Participants		Savings (GJ)	
	Target	Projected	Target	Projected
1. Residential				
Heating System Upgrade	3500	4000	105,000	120,000
Fireplace Upgrade	1000	1000	14,000	14,000
2. Commercial				
Utilization Advisory	25	45	20,000	29,000
3. Community Based				
Destination Conservation	20	46	4,000	9,000
4. Other Activities				
Awareness and Education Research & Program Design	N/A	N/A	N/A	N/A
			143,000	172,000

Total Resource Cost Test and DSM Achievement Incentive Status

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

For the 2003 portfolio (as identified in the table above), the TRC net benefit has been estimated to be $6.9 million.

Achieving between 133,070 GJ up to 177,425 GJ would result in an incentive payment of 3% of net benefits. If the projected savings of 177,000 GJ is reached (the programs are currently in process and will not be verified until later in 2004), the incentive payable to the company would be $207,000.

Greenhouse Gas Reduction

In its residential rebate offers Terasen Gas indicates to customers participating of its intent to record resulting emission reductions as part of the company's Greenhouse Gas Management Program. The net impact of these residential program savings amount to approximately 7,000 tonnes of CO2e (metric tonnes of carbon dioxide equivalent); the net impact for all programs based on current projections is approximately 9,000 tonnes CO2e.

8. SUMMARY OF COSTS

Program and administration costs as well as customer incentive costs will have remained below allowed levels in 2003:

	($000)	
	Allowed	Projected
Administration, marketing and research (DRIA)	1,627	1,400
Customer Incentives	1,585	850

BC Gas – Efficient Boiler Program

Impact Evaluation

Prepared for:

BC Gas

Prepared by:

abart & Associates Consulting Inc.

June 12, 2003

Table of Contents

Executive Summary

1.1 Introduction

The BC Gas Efficient Boiler Program provided customer incentives and technical advice to encourage the installation of mid efficiency and high efficiency boilers in new buildings and retrofit situations. The goal of the program was to reduce energy bills and increase the efficiency of space heating systems in new construction and retrofits and to reduce peak day energy consumption. The program provides the following benefits to BC Gas' commercial customers: (1) lower space heating costs through natural gas savings; (2) lower water heater costs if boilers are used for domestic water heating; (3) improved operating efficiency through appropriate boiler sizing; and (4) improved reliability from back-up systems when a multiple boiler system is used.

The BC Gas Efficient Boiler Program provided marketing and promotion, technical assistance and advice, and financial incentives for commercial customers installing new boiler systems. For mid efficiency boilers, BC Gas paid customers up to 75% of the cost difference between a standard versus a mid efficiency boiler system up to a maximum of $2.00 per 1000 Btuh. For high efficiency boilers, BC Gas paid customers up to 75% of the cost difference between a standard versus a high efficiency boiler system up to a maximum of $15.00 per 1000 Btuh. This report summarizes the result of an impact evaluation of the Efficient Boiler Program.

1.2 Objectives and Approach

This study has five main objectives as follows: (1) assess the correct attributions of measure installations, particularly by program participants; (2) establish the relative influence these services may have had on participants' decisions to install energy saving measures; (3) identify the main barriers related to BC Gas procedures surrounding this program; (4) identify opportunities for increased communication with BC Gas regarding these types of installations; (5) assess the state of market transformation toward the commercial mid and high efficiency boilers in British Columbia. These objectives are addressed in detail through more detailed evaluation conclusions below.

Because of the complexity of the Efficient Boiler Program, we used a multiple lines of evidence approach. Initial data collection involved a review of program documents, interviews with program staff, interviews with engineering consultants and manufacturers' representatives, and a focus group with BC Gas staff that explored a variety of issue involving program planning and implementation. Based on this information, the project team developed a preliminary program profile, refined issues for the study and modified the proposed methodology. It was determined that telephone surveys would be the best way to collect valid information while minimizing the response burden on customers and trade allies.

1.3 Conclusions

Conclusion 1. Rationale for the Efficient Boiler Program. Rationale for the Efficient Boiler Program was that providing potential boiler purchasers with information on the advantages of efficient boiler systems, technical advice and assistance to facilitate decision making, and financial incentives to reduce the pay back period, would result in larger numbers of more efficient boilers being installed. Review of the program and analysis of the survey results indicate that there are valid and plausible linkages among inputs, outputs, purpose and goal for each of the program activities. The Efficient Boiler Program has a valid and persuasive rationale: the basic design involving targeted incentives to reduce financial barriers and build a critical mass of activity is sound, and the specific levels of incentives chosen for mid efficiency and high efficiency boiler systems are appropriate.

Conclusion 2. Examine Customer Awareness and Satisfaction. The most important sources of program awareness were BC Gas representatives, engineering consultants and mechanical contractors, word of mouth and advertising. Satisfaction with information on the Efficient Boiler Program, with the level of incentives offered for high efficiency boilers and with the overall program are generally high. Satisfaction with technical advice and assistance on boiler selection, with the level of incentives offered for mid efficiency boilers, with the range of equipment eligible for an incentive and with the application procedure are generally lower. Awareness of and satisfaction with the Efficient Boiler Program are at significant levels.

Conclusion 3. Identify Opportunities for Improved Customer Communications. Respondents were asked to state their most preferred methods of learning about BC Gas energy efficiency programs. For customers, these included direct mail, e-mail, BC Gas website and BC Gas representatives, while for trade allies and manufacturers these included direct mail, e-mail and BC Gas representatives. More aggressive use of targeted program communications would be useful in a subsequent program.

Conclusion 4. Identify and Examine Program Barriers and Opportunities. All respondents were asked a series of questions about the importance of factors encouraging the installation of efficient boilers. The following program opportunities were statistically significant in terms of importance for all groups: recommendations from trade allies; lower energy operating costs; higher boiler efficiency; appropriate boiler sizing; and financial incentives through the program. The following program barriers were statistically significant in terms of importance for all groups: limited knowledge of efficient boilers; uncertainty that savings will be realized; high equipment costs for efficient boilers; high installation costs for efficient boilers; and concerns about reliability of efficient boiler system. Bringing these factors together, the program has done a credible job of leveraging opportunities and reducing barriers to the installation of mid efficiency and high efficiency boilers.

Conclusion 5. Assess the State of Market Transformation. The market share of high efficiency boilers increased from 7% to 10%, the market share of mid efficiency boilers decreased from 23% to 21%, and the market share of standard efficiency boilers decreased from 70% to 69% between 1995 and 2001. While the sample sizes in this study are relatively small, this change is consistent with a gradual move towards a more efficient boiler market. In particular, the 10% share for high efficiency boilers in British Columbia is substantially higher than the 2% share for high efficiency boilers in the United States.

Conclusion 6. Assess Free Riders and Free Drivers. Free riders are customers who received a financial incentive through the program but would have installed a mid efficiency or high efficiency boiler in the absence of the program. If the respondent received a financial incentive, the respondent was asked how important the incentive was in the decision to install an efficient boiler and a weighted score was then calculated to produce a free rider rate of 0.18. The implicit free rider rate of 0.18 compares favourably with other evaluations. Free drivers or spill over refers to customers who undertook additional energy savings measures as an indirect result of the program. Participants were asked how important the incentive was in the decision to undertake other retrofit measures that affected natural gas use and a spill over rate of 0.58 was calculated. Although BC Gas provided incentives only for more efficient boilers, it appears that the program generated a high degree of savings resulting from other improvements made at the time of boiler replacement. The methodology used in the impact analysis captures both free rider and spill over impacts.

Conclusion 7. Assess Program Experience including Maintenance and Reliability. Main reasons for boiler replacement were to improve boiler efficiency, because of anticipated boiler failure, to reduce energy costs, as part of a mechanical retrofit and as part of a regular life cycle replacement program. Customers were asked to assess the reliability of their boiler systems on a five-point scale where one is poor and five is excellent. Their average ratings were 3.8 for program participants, 4.1 for drop outs (customers who enrolled in the program but did not receive an incentive) and 4.2 for controls (a random selection of customers who had installed boilers, but who did not participate in the program). This suggests that customer impressions of the relative reliability of efficient boilers systems remain a constraint on more widespread adoption of efficient boilers.

Conclusion 8. Estimate Gross and Net Natural Gas Savings. Normalized weather-adjusted billing data was used to estimate the gross impact of higher efficiency boilers on natural gas consumption. For retrofits, savings were defined as pre-retrofit consumption minus post–retrofit consumption. For new buildings, there is no pre-retrofit building to serve as a baseline, so we calculated gross annual savings as control group consumption minus participant consumption. Using survey information, a free rider rate was calculated with net savings then defined as gross savings times one minus the free rider rate. Estimated net savings, inclusive of spill over, are 174.43 TJ per year for retrofit participants and 15.91 TJ per year for new building participants for a total of 190.34 TJ per year. Estimated peak day savings are about 1.047 TJ. Carbon dioxide reductions are about 6.35 kilotonnes per year.

Conclusion 9. Identify Customer Costs. Analysis of cost information indicates that the program may be paying about 73% of incremental costs for high efficiency boilers, but about 44% of incremental costs for mid efficiency boilers. Participant costs are estimated at $1,997,000.

Conclusion 10. Determine Customer Needs for a New Program. Trade allies and manufacturers were asked which segment a future program, if one were to be introduced, should target. The top four segments for trade allies and manufacturers were office, institutional, multi-family residential and hospitality. Stakeholders suggested that the program could include envelope measures, steam boilers, energy management controls, roof top heaters and domestic hot water.

1.4 Recommendations

Recommendation 1. Support a renewed Efficient Boiler Program as a means of providing value to BC Gas' 70,000 business customers.

Recommendation 2. Include both strategic conservation and load retention as utility benefits of a new efficient boiler program.

Recommendation 3. Target key sectors such as institutional, offices and multifamily residential to build a critical mass of activity, and also target, in particular, new buildings to reduce lost opportunities.

Recommendation 4. Build on relationships with trade allies to strengthen promotional efforts, increase program awareness and improve participation rates.

Recommendation 5. Provide education and training for customers, possibly focussing on the BC Gas website as a tool, and provide technical advice and assistance for engineering consultants and contractors.

1 Introduction

The BC Gas Efficient Boiler Program began in 1995, with applications closing at the end of 2000, and installations continuing through the end of 2001. The program provided customer incentives and technical advice to encourage the installation of mid efficiency and high efficiency boilers in new buildings and retrofit situations. The goal of the program was to reduce energy bills and increase the efficiency of space heating systems in new construction and retrofits and to reduce peak day energy consumption. Reducing energy bills and increasing the efficiency of space heating systems provides value to commercial customers and helps to retain the natural gas load in the face of competition for other energy sources. Reducing peak day consumption reduces the need to expand the natural gas distribution system with consequent savings to BC Gas and its customers.

More specifically the program provides the following benefits to BC Gas' commercial customers:

- Lower space heating costs through natural gas savings.
- Lower water heating costs if boilers are used for domestic water heating.
- Improved operating efficiency through appropriate boiler sizing.
- Improved reliability from back-up systems when a multiple boiler system is used.

Although mid efficiency and high efficiency boilers are cost effective for many commercial customers, market barriers have inhibited appropriate levels of market penetration. These market barriers include the following:

- Higher initial or first costs for boilers and ancillary equipment and installation for mid efficiency and high efficiency boilers than for standard efficiency boilers.
- Limited contractor awareness and knowledge of the benefits and features of mid and high efficiency boiler systems.
- Limited customer awareness and knowledge of the benefits and features of mid and high efficiency boiler systems.
- Some initial problems with premature failure of high efficiency, condensing boiler systems.
- Higher retrofit piping costs for condensing boilers.

To overcome these barriers, the BC Gas Efficient Boiler Program provided marketing and promotion, technical assistance and advice, and financial incentives for commercial customers installing new boiler systems. For mid efficiency boilers, BC Gas paid customers up to 75% of the cost difference between a standard versus a mid efficiency boiler system up to a maximum of $2.00 per 1000 Btuh. For high efficiency boilers, BC Gas paid customers up to 75% of the cost difference between a standard versus a high efficiency boiler system up to a maximum of $15.00 per 1000 Btuh. The incentives were calculated on space heating loads only, because the space heating load has the greatest implications for natural gas distribution peak, although more efficient boilers would also increase the energy efficiency of other loads on the boiler.

This report summarizes the result of an impact evaluation of the Efficient Boiler Program. The structure of the report is as follows. Section 2 outlines the study objectives and approach. Section 3 provides program background, describes key program activities and assesses the rationale for the program. Section 4 reviews previous research on efficient boilers, including a description of programs offered to commercial customers by other natural gas utilities. Section 5 summarizes the results of the detailed surveys of customers, engineers and contractors, and manufacturers' representatives. Section 6 assesses program impact using weather adjusted billing analysis and free rider and free driver analysis. Section 7 provides the principal conclusions of the study. Section 8 offers recommendations on program redesign and implementation for management consideration.

2 Objectives and Approach

2.1 Study Objectives

This study has five main objectives as follows:

- Objective 1. Assess the correct attributions of measure installations, particularly by program participants.
- Objective 2. Establish the relative influence these services may have had on participants' decisions to install this energy saving measure.
- Objective 3. Identify the main barriers related to BC Gas procedures surrounding this program.
- Objective 4. Identify opportunities for increased communication with BC Gas regarding these types of installations.
- Objective 5. Assess the state of market transformation toward the commercial mid and high efficiency boilers in British Columbia.

2.2 Study Approach

Because of the complexity of the Efficient Boiler Program, we used a multiple lines of evidence approach. A multiple lines of evidence approach is useful when there are a number of distinct issues that cannot be adequately addressed through a single method or source of information. For this study there were ten main evaluation issues, which can be summarized as follows:

- Issue 1. Examine the rationale for the Efficient Boiler Program. The objective is to determine whether or not there is a sound and valid rationale for the program and its activities.
- Issue 2. Examine customer awareness and satisfaction. The objective is to understand program efforts and actions from consumer and trade ally perspectives.
- Issue 3. Identify program opportunities for improved customer communications. The objective is to determine how commercial customers wish to communicate with BC Gas on energy efficiency.
- Issue 4. Identify and examine program barriers and opportunities. The objective is to determine the critical barriers to installation and use of energy efficient boilers and the key opportunities for using energy efficient boilers.
- Issue 5. Assess the state of market transformation. The objective is to assess the current market for efficient boilers, the extent of market transformation that has taken place and the remaining market potential.
- Issue 6. Assess free riders and free drivers. The objective is to assess key market effects including free riders and free drivers (spill over).
- Issue 7. Assess program experience including maintenance and reliability. The objective is to assess key elements of the program experience from the user perspective.
- Issue 8. Estimate gross and net natural gas savings and carbon dioxide reductions. The objective is to develop accurate and credible

analysis of natural gas savings and CO_2 reductions for retrofits and for new buildings.

- Issue 9. Identify customer costs. The objective is to develop an accurate analysis of customer costs.
- Issue 10. Determine customer needs for a new program. The objective is to understand likely future growth of the natural gas boiler market and type of program that would meet customer needs.

Initial data collection involved a review of program documents, interviews with program staff, interviews with engineering consultants and manufacturers' representatives, and a focus group that explored a variety of issues involving program planning and implementation. Based on this information, the project team developed a preliminary program profile, refined issues for the study and modified the proposed methodology. Evaluation issues as well as data sources and methods for each issue are summarized in Exhibit 2.1.

Exhibit 2.1. Evaluation Issues, Data Sources and Methods

Issue	Data sources	Methods
1.Examine the rationale for the Efficient Boiler Program	Program documentation and previous research Interviews	Logic framework analysis
2.Assess customer awareness and satisfaction	Interviews Surveys	Comparisons of participant, dropout and control group responses
3.Identify opportunities for improved customer communications	Interviews Surveys	Comparisons of participant, dropout and control group responses
4.Identify and examine program barriers and opportunities	Interviews Surveys Literature review	SWOT (strengths, weaknesses, opportunities, threats)
5.Assess the state of market transformation	Literature review Surveys	Market penetration analysis
6.Assess free riders and free drivers (spill over)	Interviews Surveys	Free rider analysis Free driver analysis
7.Assess program experience including maintenance/reliability	Interviews Surveys	Comparisons of participant, dropout and control groups
8.Estimate gross and net natural gas savings and carbon dioxide reductions for participants	Program data Surveys Gas billing/weather files	Weather normalized gas consumption and free rider analysis
9.Identify program and customer costs	Program data Surveys	Cost analysis
10.Determine customer needs for a new program	Literature review Surveys	Comparisons of participant, dropout and control groups

It was determined that telephone surveys would be the best way to collect valid information while minimizing the response burden on customers and trade allies. The surveys were designed to provide as much comparability across respondent groups as was feasible. This maximized the number of issues for which responses could be compared. The draft survey instruments were extensively reviewed with BC Gas staff and modified in response to comments. The final sample sizes by strata are shown in Exhibit 2.2.

Identifying and contacting survey respondents to produce adequate sample sizes proved to be a major challenge. There were several reasons for this:

- Some projects went as far back in time as 1994 so it was hard to find individuals knowledgeable about the initial application.
- Some buildings had changed ownership and it was difficult to find someone involved with the original heating system design decisions.
- Some applications involved engineering consultants who had little involvement with the building and its operation in the post-commissioning period.

Exhibit 2.2. Sample Sizes by Strata

Strata	Definition	Sample size
Participants	Customers who received an incentive under the program	62
Dropouts	Customers who initiated the incentive process but received no incentive. They may or may not have installed a new boiler.	7
Controls	Customers who installed a boiler during the program period but were not participants or drop outs	25
Engineers and contractors	Trade allies who provided services for the design or installation of boiler systems	19
Manufacturers' representatives	Representatives of manufacturers of boiler systems	8
Total		121

The preliminary survey questionnaires were carefully pre-tested by telephone. The trade allies or engineers and contractors survey and the manufacturers representatives surveys were pre-tested through in-person interviews. This allowed us to get good insights into question design for these groups and better appreciate the nature of the boiler market. The customers survey was pre-tested by phone in the presence of the project team. This allowed the project team to understand customer reactions to and understanding of the survey. A number of key modifications were made to the survey design as part of the pre-test.

The telephone survey was conducted using a DASH-CATI system. Interviewers were fully briefed before the survey was conducted to ensure that they understood the intent of each question as well as the overall purpose of the survey. Up to ten calls were made to each potential respondent to minimize response bias and to collect as many valid responses as feasible. Complete information on response rates and reasons for non-completion of each survey attempt were kept.

Qualifying questions were asked at the beginning of the survey to ensure that the most appropriate individual completed the survey. As the answers were given, they were entered into an electronic database. Because the number of completed responses from the initial telephone survey was viewed as inadequate, additional measures were taken to increase the response rate. BC Gas contacted key customers and solicited support for the survey. Fax back surveys were provided to those who agreed to participate. Two versions of the fax back survey were used: the first modified the full customer survey to make it suitable for fax use; the second eliminated any material not directly related to the impact part of the study, and was provided to customers who were the respondents for multiple buildings. Responses were then edited and cleaned. Preliminary analysis involved simple tabulations of data by question. Inspection of this information then suggested potentially interesting relationships among responses and a variety of cross tabulations were run.

Normalized weather-adjusted billing data was used to estimate the gross impact of higher efficiency boilers on natural gas consumption. The steps involved here were as follows:

- Determine pre and post periods for each account (as appropriate).
- Match natural gas consumption of each billing period to heating degree-days for an appropriate location.
- Regress average daily consumption on average daily heating degree-days.
- Estimate annual normalized consumption as the sum of (365*intercept coefficient) plus (slope coefficient *typical annual heating degree days).

For retrofits, savings were defined as pre-retrofit consumption minus post-retrofit consumption for controls. For new buildings, there is no pre-retrofit building to serve as a baseline. We therefore calculated gross annual savings as control group consumption minus participant consumption. Using survey information, a free rider rate was calculated with net savings then defined as gross savings times one minus the free rider rate. Because whole building billing information was used in these calculations, spill over was automatically included in these estimates. Engineering estimates were used to calculate carbon dioxide emissions reductions associated with lower natural gas use.

3 Program Description

3.1 Program Development

It is estimated that at program launch in 1995, about 1500 boilers were sold per year in British Columbia. Some information was available on key market segments. Based on data from provincial government sources, there were some 11,960 non-industrial buildings with large natural gas loads. The distribution of these non-industrial buildings with large natural gas loads buildings was as follows: multi-family residential – 53%; office and commercial – 37%; and institutional – 10%.

Despite the potential for cost effective installation of energy efficient boiler systems, it was concluded that there were a number of barriers inhibiting their use. These barriers included:

- Higher initial or first costs for boilers and ancillary equipment and installation for mid efficiency and high efficiency boilers than for standard efficiency boilers.
- Limited contractor awareness and knowledge of the benefits and features of mid efficiency and high efficiency boilers systems.
- Limited customer awareness and knowledge of the benefits and features of mid efficiency and high efficiency boilers systems.
- Some initial problems with premature failure of high efficiency, condensing boiler systems.
- Split incentives so that the owner does not capture the benefits of a more efficient building.

In developing the program, BC Gas staff worked closely with engineering consultants, designers, suppliers and developers. Initially interest focussed on high efficiency or condensing boilers as these offered the greatest potential savings. However, high efficiency boilers appeared to have potential only in some applications, so consequently there was interest in developing a mid efficiency boiler program component. Critical aspects of program design included eligible boiler size, definition of mid efficiency boilers, definition of high efficiency boilers, mid efficiency boiler incentive levels and high efficiency boiler levels. These parameters were set at the levels shown in Exhibit 3.1 in the initial design. In response to comments from stakeholders, the final parameters were established as shown in Exhibit 3.1.

Exhibit 3.1. Original and Final Program Design Parameters

Program parameter	Initial design	Final design	Reason for any changes
Eligible boiler size	Boiler plant size from 300 MBtuh to 5000 MBtuh	Boiler plant size 300 MBtuh to 6000 Mbtuh input with maximum individual boiler size of 3000 Mbtuh	Provide more flexibility for commercial customers to apply efficient technology
Mid efficiency definition	Combustion air modulation boilers CGA rated at 78% steady-state efficiency with individual vent dampers or individual power venting and intermittent pilot ignition	Boilers with steady state efficiency of 85% plus approved intermittent ignition and an automatic vent damper or sidewall power venter	Reduce free ridership since baseline survey indicated higher than expected number of mid efficiency boilers sold in 1994 under old definition and increase energy and peak savings
Mid efficiency incentive level	$2.00/MBH input	Maximum of $2.00/MBH input to 75% of incremental cost of upgrade	Ensure appropriate investment by customer
High efficiency definition	Boilers that utilize condensing or pulse combustion technology	Boiler designed to operate with water return temperature below 130 degrees F	Guarantee that high efficiency boilers are condensing under all operating conditions
High efficiency incentive level	$16.00/MBH input	Maximum of $15.00/MBH input to 75% of incremental costs of upgrade	Ensure appropriate investment by customer

3.2 Program Marketing

The nature and level of market interest was quite different in the Coast and the Interior. The main segments that participated in the program on the Coast were multi-family residential, where a key concern of owners and strata council members was to reduce heating costs, and offices where significant penetration was reached despite the typical first cost orientation of developers.

In the Interior, the key segments included schools, hospitals, nursing homes and offices. For hospitals and schools, public money was available for higher upfront capital costs to reduce ongoing fuel costs. Currently program staff view this opportunity to reduce heating costs, while retaining natural gas loads for multi-family residential buildings on the Interior, as being reduced because of increased penetration of ground source heat pumps and electric heat.

The desired level of program awareness was a complicated issue. The program wanted customer awareness to be reasonably high to get adequate levels of knowledge, interest and participation. But program resources were limited, and too high a level of awareness would have overwhelmed delivery capacity. Levels of awareness and interest achieved were probably about right given delivery capacity.

During the early days of the program, commodity price was low and that created a barrier to adoption. Still some customers were looking for help with capital projects, particularly where the anticipated pay back was over a longer period. Marketing was very dependent on the actions of a limited number of individual BC Gas customer representatives. A typical approach was to identify a building where a boiler was going to be put in, but the planned efficiency level of the system was not high. The building manager or operator was approached and told about the nature and procedures of the program and the long-term advantages of efficient boilers. Customer pay-back period, in the absence of an incentive, was perhaps ten years for high efficiency boilers and somewhat less for mid efficiency which led to some difficulties in marketing efficient boilers.

3.3 Technical Advice and Support

Getting to an 85% seasonal efficiency level, one key goal of the program, creates some design and cost challenges. These include:

- Need for stainless steel vents because of condensate issues.
- Change from atmospheric pressure to positive pressure creates some design issues.
- Existing piping may not be suitable for a new system.
- Higher levels of management and operational technical sophistication and greater attention to routine maintenance may be needed for higher efficiency systems.

These factors led to a perceived need by program staff for training, education, technical advice and assistance for engineering consultants and heating contractors as well as owners and developers. The reasons for this are: first, that some engineering firms and many contractors have standard designs and are reluctant to change; and second that many operators and facilities managers have limited knowledge of efficient boilers systems, their operation and maintenance.

The program plan had components to deal with this issue but these were largely not implemented. Initially most participants were mid efficiency so that training and education were less of an issue. Available infrastructure seemed to cope adequately with design, installation and commissioning of mid efficiency boilers. Maintenance and operations were a bit more of an issue. Later in the program there were more high efficiency installations so that technical competence became more of an issue. Still, the program appears to have done an excellent job, though, given the resources available.

3.4 Financial Incentives

The Efficient Boiler Program provided incentives only for the space heating load, since the utility's purpose was to reduce peak demand, because natural gas is more expensive at peak. Other loads including, in particular, domestic hot water and process heat are comparatively flat or do not contribute proportionately to peak, so that incentives for other natural gas loads seemed unjustified. Some utility staff felt during implementation that the incentive level for high efficiency boilers was about right, but that for mid efficiency boilers it was possibly too low.

The incentive levels were based on the best estimates of incremental capital costs of mid efficiency and high efficiency boilers over standard efficiency boilers, but getting good estimates of these incremental costs was difficult. The BC Gas Efficient Boiler Program provided marketing and promotion, technical assistance and advice, and financial incentives for commercial customers installing new boiler systems. For mid efficiency boilers, BC Gas paid customers up to 75% of the cost difference between a standard versus a mid efficiency boiler system up to a maximum of $2.00 per 1000 Btuh. For high efficiency boilers, BC Gas paid customers up to 75% of the cost difference between a standard versus a high efficiency boiler system up to a maximum of $15.00 per 1000 Btuh.

The program required that mid efficiency boilers have minimum steady state combustion efficiency of 85%. The boiler must also incorporate intermittent ignition with one of the following: sidewall power venting; automatic vent damper; power design burner. The Mid Efficiency Eligible Boiler list contained boilers with efficiencies ranging from 85% to 90%.

The program also required that high efficiency boilers be designed and approved by the manufacturer to operate under flue gas condensing conditions with return water temperature as low as 80 degrees Fahrenheit. In addition, the system water return temperature was not to exceed 130 degrees Fahrenheit under all operating conditions. The High Efficiency Eligible Boiler list contained boilers with efficiencies from 88% to 92%.

3.5 Program Rationale

The rationale for the Efficient Boiler Program was based on the premise that there are significant market barriers limiting the penetration of higher efficiency boilers in appropriate applications and that these barriers can be successfully addressed with an appropriate information, technical support and financial incentive program. Exhibit 3.2 summarizes the rationale for the program and its activities. For each activity, the main linkages among inputs-outputs–purpose-goal are shown. There are strong and plausible linkages for each part of this chain confirming the logic of program design and the overall rationale for the program.

Exhibit 3.2. Program Logic Model

	Program development	Program marketing	Technical advice and support	Financial incentives
Inputs	Assess market barriers and opportunities and develop appropriate DSM program	Advertising and promotional activities	Brochures, specifications and technical advice	Incentive process
Outputs	DSM program that addresses needs of commercial customers	Customer and trade ally awareness of program increased	Trade allies and customers knowledgeable about mid and high efficiency boilers	Pay back for mid efficiency and high efficiency boilers reduced
Purpose	Encourage the installation of mid efficiency and high efficiency natural gas boiler systems in new buildings and retrofit situations			
Goal	Reduce energy bills and increase the efficiency of space heating systems in new construction and retrofits and reduce peak day consumption			

4 Literature and Documents Review

4.1 Pre-launch Program Research

As part of the development of the program design, three major surveys were carried out before program launch. The first was a survey of manufacturers' representatives, contractors and gas utilities aimed at understanding trade ally views on mid efficiency and high efficiency boilers. The second was a survey of manufacturers representatives that focussed on market share, potential free riders and implementation issues. The third was a survey of engineering consultants that examined in detail the number of mid efficiency and high efficiency boilers being installed, and installation and maintenance issues.

Some key findings of these surveys were as follows:

- An efficient boiler program should emphasize strategies to influence both the demand side and the supply side of the market.
- Information on key aspects such as reliability, maintenance and pay-back of mid efficiency and high efficiency boilers available from trade allies and other natural gas utilities was somewhat fragmentary, but this information indicated that there was significant market potential.
- Education and training of contractors, developers and housing managers, manufacturers' representatives and other trade allies is crucial for successful implementation.
- An efficient boiler program would have to be carefully designed to minimize free rider problems.
- Mid efficiency boilers should have a minimum steady state thermal efficiency of 85 and must include: either induced draft, sidewall power venting, automatic vent damper or power burner design as well as intermittent ignition.

Key conclusions of this research and analysis were that mid efficiency and high efficiency boilers "have a low market penetration, offer significant peak GJ savings and participant energy savings, offer savings that are persistent and lend themselves to a common delivery approach."

4.2 Efficient Boiler Program Process Evaluation

A Process Evaluation of the first year of program implementation was completed in November 1996 [Ference Weicker (1996)]. The principal purpose of the Process Evaluation was to assess the design and implementation of the BC Gas Efficient Boiler Program. The study was based on interviews with program staff and stakeholders, a review of program files and management information systems, and a comparison with similar natural gas heating-based energy efficiency programs in North America.

Selected findings of the Process Evaluation included the following:

- The participation rate for the first year was lower than expected, with the low take-up attributed to delay in program launch and relatively low levels of advertising and promotion.

- The boiler market size in 1995 was estimated at some 1500 boilers in British Columbia with about 7% being high efficiency, 23% being mid efficiency and 70% standard efficiency.
- The level of Efficient Boiler Program awareness was viewed as relatively low, with about 27% of non-participants and 58% of trade allies aware of the program.
- The program requirement of a minimum level of boiler efficiency of 85% was generally felt to be appropriate by survey respondents, and lowering this required efficiency level would likely result in a high free rider rate.
- About 65% of respondents viewed the current level of incentives as an appropriate one.
- Only two comparable programs were identified and these had limited relevance for the Efficient Boiler Program: The Gas Furnaces and Boilers program of Baltimore Gas and Electric Company, that was limited to residential customers; and Consumers Gas Boiler Rental Program of Ontario, that focussed on residential water heater rentals.

The main conclusion of the Process Evaluation was that “the current procedures and incentives employed to deliver the Efficient Boiler Program are satisfactory as the degree of satisfaction by program participants is relatively high. The major concern regarding program delivery is the low program participation rate. The most effective method of increasing the program participation rate is to increase the effort devoted to marketing and promotion of the Efficient Boiler Program.”

4.3 Secondary Research

The published research on efficient boiler programs appears to be quite limited. The most useful document is a Market Assessment for Condensing Boilers in Commercial Heating Applications published by the Consortium for Energy Efficiency (2001). The basic purpose of this study was to assess the market for gas fired condensing boilers in the commercial sector. The basic approach was to develop a functional definition of a condensing boiler, identify existing condensing boilers that meet this definition, identify competing technologies and assess market potential in the schools, office buildings, federal buildings and apartment buildings segments. Key findings include the following:

- Current Market Characteristics. Condensing boilers occupy about 2% of the boiler market. The estimated American market for commercial scale condensing boilers (>3,000,000 Btuh) was about 700 units per year and for residential units (<300,000 Btuh) was about 7,000 units per year in 1999.
- Market Projections. Under a “business as usual scenario” the market share of condensing boilers would remain at about 2% while under a fully supported market transformation scenario this could rise to perhaps 28% of the market by 2020.
- Technical Barriers. The need for low water return temperatures and for a minimum two-pipe hydronic distribution system severely limits the potential penetration of condensing boilers in the retrofit market.

- Economic barriers. Most commercial building owners do not pay their tenants heating bills so first cost considerations are important, particularly as condensing boilers require expensive corrosion resistant materials and controls.
- Institutional barriers. The absence of appropriate infrastructure or an organization to promote high efficiency boilers and develop training, marketing and design tool is a key market barrier.
- Market segments. Of the four market segments intensively studied, schools and federal office buildings are attractive because of the life cycle cost orientation of authorities, while multi-family residential is less attractive and market for office buildings is limited because major space conditioning load is for cooling.

4.4 Comparison with Other Natural Gas Programs

An internet search was undertaken to identify other natural gas utilities in North America that have energy conservation programs for their commercial customers. Although emphasis was on efficient boiler programs, any utility programs found that were primarily directed at reducing natural gas consumption in commercial buildings were reviewed.

This search found seven major energy conservation programs with about twenty participating utilities all together. Each of these seven programs is summarized with a focus on:

- Types of equipment eligible for an incentive.
- Capacity ranges eligible for an incentive.
- Efficiency levels eligible for an incentive.
- Size of the incentive, expressed in Canadian or United Sates dollars as appropriate.

Gaz Metropolitain has six energy efficient equipment programs aimed at its commercial customers. A summary description of these is as follows.

- Condensing or direct contact boilers. This includes condensing boilers and direct-contact boilers up to 35 million Btuh with efficiency equal to or greater than 90%. The incentive is $600 to $20,000 depending on the installed equipment’s capacity or the volume of the building to be heated.
- Superior energy-efficiency boiler. This includes high performance hot water or steam boilers 300,000 Btuh and higher, with efficiency of 85%. The incentive is $1,000 to $5,900 depending on the installed equipment’s capacity or the volume of the building to be heated.
- Superior energy-efficiency commercial water heater (that is, large capacity hot water heaters). This includes appliances of 75,000 BTU/hr. and higher, with efficiency equal to or greater than 85%. The incentive is $600 to $3,000 depending on the equipment’s capacity.
- Superior energy-efficiency small boiler. This includes high-performance hot-water boilers 300,000 Btuh and lower, with

efficiency of 85%. The incentive is $600.

- High-efficiency hot-air furnace. This includes appliances of 225,000 Btuh and lower, with efficiency greater than or equal to 90%.
- Superior energy-efficiency water heater (small capacity). This includes appliances of 75,000 Btuh and lower.

The Enbridge MultiChoice Program offers scaled incentives where if one measure is installed the incentive is $0.05/m^3 of gas saved up to a maximum of $30,000 per building and if three (or more) measures are installed the incentive is $0.10/m^3 of gas saved up to a maximum of $30,000 per building, based on projected first-year natural gas savings, for projects with a simple pay-back greater than 2.5 years. Typical measures eligible for incentives include:

- Higher efficiency boilers including mid efficiency to high efficiency boilers, reflective panels for radiators, controls and other boiler improvements.
- Higher efficiency combination water and space heating systems.
- Controls, including Building Energy Management Systems.
- Building envelope upgrades including windows and window film, air sealing measures, insulation improvements above R-12.
- Water conservation including low flow showerheads and faucet aerators and horizontal-axis washing machines.
- Efficient make up air including heat recovery, controls, and Solarwall exterior cladding systems.

Gas Networks (including members Bay State Gas, Berkshire Gas, New England Gas Company, Flitchburg Gas and Electric, KeySpan Energy Delivery and NSTAR Gas) offers a variety of commercial and industrial programs including the following as well as some additional programs offered by specific member utilities:

- Heating equipment including furnaces (AFUE greater than or equal to 90%) with $200 rebate.
- Forced hot water boilers (AFUE greater than or equal to 85%) with $500 rebate.
- Steam boilers (AFUE rating greater than or equal to 82%) with $400 rebate.
- Natural gas water heaters (energy factor greater than or equal to 0.61) with $100 rebate.
- Indirect-fired storage tank water haters (30 to 75 gallons connected to a natural gas water heating system) with $100 rebate.
- Low intensity infrared heating equipment (maximum five, natural gas heating) with $500 rebate per unit.

Pacific Gas and Electric provides the Express Efficiency Program to small and medium sized non-residential customers with monthly consumption less than 20,800 therms for a wide variety of measures, to a maximum of $25,00 rebate per account, including:

- Steam heating boilers (input rating less than 300 MBtuh and AFUE greater than or equal to 77%) with rebate $2.00/MBtuh.
- Small water heating boiler (input rating less than 300 MBtuh and AFUE greater than or equal to 82%) with rebate $2.00 per MBtuh.
- Large space heating boiler (input rating greater than or equal to 300,000 MBtuh and combustion efficiency greater than or equal to 82%) with rebate $2.00 per MBtuh.
- Hot water or steam process boiler/direct contact water heater for industrial customers (minimum combustion efficiency of 82%) with rebate of $2.00 per MBtuh.
- Storage hot water heater (with input less than or equal to 75,000 Btuh energy and energy factor 0.58 or greater depending on volume) with rebate $2.00 per MBtuh.

Saving by Design is the California utilities (Pacific Gas and Electric, Southern California Edison, Southern California Gas, San Diego Gas and Electric) new construction incentive program that offers incentives through design assistance, owner incentives and design team incentives using (a) the whole building approach used for projects where the design team can work closely to integrate the building's energy systems, and (b) the systems approach used for performance based analysis of simpler buildings. Eligibility requirements and incentive rates are fairly complex. Incentives generally require that the building or relevant systems better Title 24 standards by 10% or more. For example, under the whole building incentive rates, owner incentives rise from $0.34 per annualised therm saved at 10 % savings above Title 24 to $.80 per annualised therm saved at 30% over Title 24. Using the Title 24 standards, Savings by Design minimums for selected measures include the following:

- Steam or water boilers (input rating less than 300 MBtuh with AFUE 81.4% or greater for steam boilers and AFUE 84.4% or greater for water boilers).
- Steam or water boilers (input rating greater than or equal to 300 MBtuh and less than 2500 MBtuh and thermal efficiency 79.5% or greater).
- Steam or water boilers (input rating greater than 2500 MBtuh and combustion efficiency greater than or equal to 84.8%).
- Small central furnaces (input rating less than 225 MBtuh and AFUE greater than or equal to 90%).

CenterPoint/Minnegasco offers rebates for a variety of heating system measures as based on engineering calculations. Measures covered include:

- New heating system for customers purchasing and installing a high-efficiency natural gas forced-air furnace (input rating less than 225,000 with AFUE 92% or higher) with rebate of $1000, unit heater or duct furnace (all sizes with 83% with AFUE 83%) rebate of 10% of equipment costs to $1000, boiler reset or cut-out controls (up to 25% of equipment costs with $25,000 system cap).
- Heating system retrofit including steam trap replacement with rebate

of 35% of equipment costs to $10,000 per building, continuous air/fuel modulating burners with rebate of 25% of equipment costs up to $7500 per burner, single pipe steam balancing with rebate of 25% of equipment costs up to $1000, vent dampers with rebate up to 25% of equipment costs up to $250 per boiler, steam to hydronic distribution conversion with rebate up to 25% of equipment costs up to $12,500.

- Boiler tune-up for commercial customers with firm annual energy consumption of 50,000 therms or less with rebate of 25% of tune up costs up to $200 per boiler and up to $1000 per facility.

New Jersey Smart Start Buildings is the New Jersey utilities (Connectiv, Jersey Central Power and Light, New Jersey Natural Gas, Elizabethtown Natural Gas, PSE&G, Rockland Electric, South Jersey Gas) program for commercial and industrial customers. Gas measures covered include:

- Boilers (input capacity less than or equal to 1500 MBH) with rebate of $300 per unit.
- Boilers (input capacity greater than 1500 MBH) with customized incentives.
- Furnaces with rebate of $300 per unit.

Exhibit 4.1 provides a comparison of the main features of the commercial natural gas programs examined with an emphasis on the range of eligible equipment and on incentive levels. With respect to the range of equipment eligible, the BC Gas program is the narrowest of those examined, including only mid efficiency and high efficiency boilers in the portfolio. Other program include at least one other end use beside boilers, including water heating, system controls, and envelope measures. With respect to incentive levels, comparisons are complicated by the differing payment basis for various programs, but it appears that BC Gas incentives for mid efficiency boilers are at the lower end of the observed incentive range while BC Gas incentives for high efficiency boilers are at the upper end of the observed incentive range.

Exhibit 4.1. Comparison of Commercial Natural Gas DSM Programs

Utility	Eligible equipment	Incentive level
BC Gas	Mid efficiency boilers High efficiency boilers	75% of incremental cost to $2.00 per MBtuh 75% of incremental cost to $15.00 per MBtuh
Gaz Metropolitain	Mid efficiency boilers High efficiency boilers Superior efficiency hot water tank	$1,000 to $5,900 depending on capacity Up to $20,000 depending on capacity $1,000 to $5,900 depending on capacity
Enbridge	Mid efficiency boilers High efficiency boilers Combination water and space heating systems Energy management systems Building envelope upgrades	$0.05 /m^3 of gas saved for one measure or $0.10/m^3 of gas saved if 3 measures installed to $30,000 per building
Gas Networks (BSG, BG, NEGC, FG&E, KSED and NSTAR Gas)	Mid efficiency boilers High efficiency furnaces High efficiency water heaters Low intensity infrared heating equipment	US$500 US$200 US$100 US$500 per unit
Pacific Gas and Electric	Mid efficiency boilers Efficient water heaters	US$2.00 per MBtuh US$2.00 per MBtuh
California utilities (PG&E, SCE, SCG, SDG&E)	Mid efficiency boilers High efficiency boilers Small central furnaces	US$0.34 per annualised therm at 10% savings to US$0.80 per annualised therm at 30% savings above Title 24
CenterPoint/Minnegasco	New heating system Heating system retrofit Boiler tune up	10% of equipment costs to US$1,000 35% of equipment costs to US%10,000 per building US$1000
New Jersey Utilities (Connectiv, JCP&L, NJNG, ENG, PSE&G, RE, SJG)	Small efficient boilers Large efficient boilers Efficient furnaces	US$300 Custom incentives based on savings US$300

5 Survey Results

5.1 Customer Awareness and Satisfaction

The objective of this issue was to understand the program actions and efforts from the consumer and trade ally perspectives. This included an assessment of key program activities such as:

- Program information.
- Technical advice.
- Incentives.
- Equipment eligibility.
- Application procedures.

Awareness of the Efficient Boiler Program for various groups is shown in Exhibit 5.1. Levels of awareness of the Efficient Boiler program are generally quite high. The share of respondents aware of the program is 68% for participants, 71% for dropouts, 44% for controls, 90% for trade allies and 100% for manufacturers. Given the limited level of resources available for advertising and promotion, these are significant awareness levels.

Exhibit 5.1. Awareness of Efficient Boiler Program (percentage of column)

	Participants (n=62)	Dropouts (n=7)	Controls (n=25)	Trade allies (n=19)	Manufacturers (n=8)
Aware	68%	71%	44%	90%	100%
Not aware	5%	29%	56%	10%	-
DK/NR	27%	-	-	-	-

The sources of initial program awareness are shown in Exhibit 5.2. These vary quite a lot depending on the respondent group, reflecting the fact that different clients use a variety of information channels, but BC Gas representatives are important sources of information for all groups of respondents. For participants, the most important sources are BC Gas representatives, engineering consultants and mechanical contractors. For dropouts, the most important sources are engineering consultants, BC Gas representatives and word of mouth. For the control group, the most important sources are BC Gas representatives and advertising. For trade allies, the most important source is BC Gas representatives followed distantly by program literature, advertising and word of mouth. For manufacturers, the most important sources of information are BC Gas representatives and other BC Gas contact.

Note that the column entries do not necessarily sum to 100% because of non-response and/or multiple responses to this question.

Exhibit 5.2. Source of Initial Program Awareness (percentage of column)

	Participants (n=42)	Dropouts (n=5)	Controls (n=11)	Trade allies (n=17)	Manufacturers (n=8)
Program literature	7%	-	-	12%	-
BC Gas rep	31%	20%	27%	47%	62%
Other BC Gas contact	-	-	-	6%	25%
BC Gas website	2%	-	-	-	-
Engineering consultant	23%	40%	9%	-	-
Boiler supplier	5%	-	-	6%	-
Mechanical contractor	17%	-	-	-	-
Advertising	5%	-	27%	12%	-
Word of mouth	7%	20%	9%	12%	-

Customer satisfaction with a variety of program components is shown in the following Exhibit 5.3. For each of these elements, respondents were asked how satisfied they were on a five-point scale where one is not at all satisfied and five is very satisfied. The mean score is shown in each cell with the standard error below in parentheses. It is useful to examine the significance of the average satisfaction scores under the assumption that indifferent performance would result in an average score of 2.5, so that a score significantly different from 2.5, at the 95% confidence level, is potentially of interest. A mean value significantly below 2.5 suggests there is significant room for improvement, while a mean value significantly above 2.5 suggests the area is doing well. Values that are statistically different from 2.5 are indicated by an asterisk.

Satisfaction with information on the Efficient Boiler Program is generally high at 3.9 for participants, 3.2 for dropouts, 4,4 for controls, 3.8 for trade allies and 3.9 for manufacturers and is statistically significant for four of the five groups. This suggests that the information component was effective.

Satisfaction with technical advice and assistance on boiler selection is lower at 3.4 for participants, 3.2 for dropouts, 4.0 for controls, 2.8 for trade allies and 2.2 for manufacturers and is significant for two groups. This suggests that technical advice and assistance provided by BC Gas on the Efficient Boiler Program could usefully be strengthened, which is consistent with our finding above that planned activities in this area were largely not implemented.

Satisfaction with the level of incentives offered for mid-efficiency boilers is generally the most poorly rated program component at 3.6 for participants, 2.2

for dropouts, 3.0 for controls, 3.0 for trade allies and 1.6 for manufacturers and is significant for two groups. This suggests that incentives for mid efficiency boilers were just adequate to meet program capture or take-up objectives.

Satisfaction with the level of incentives offered for high efficiency boilers is higher at 3.8 for participants, 3.2 for dropouts, 4.0 for controls, 3.5 for trade allies and 4.1 for manufacturers and is significant for four groups. This suggests that incentives for high efficiency equipment were at an adequate level.

Satisfaction with the range of equipment eligible for an incentive was 3.4 for participants, 2.4 for dropouts, 3.6 for controls, 3.3 for trade allies and 3.5 for manufacturers and is significant for four of the groups, although not for drop outs, suggesting that the range of eligible equipment was appropriate.

Satisfaction with the application procedure is similar at 3.6 for participants, 2.6 for dropouts, 3.9 for controls, 3.3 for trade allies and 2.6 for manufacturers and is significant for three groups. This suggests that the application procedure worked reasonably well.

Satisfaction with the overall program is 3.8 for participants, 3.0 for dropouts, 3.6 for controls, 3.4 for trade allies and 2.9 for manufacturers and is significant for three groups. This suggests that the overall program met the needs of most client groups adequately.

Exhibit 5.3. Satisfaction with Program Elements (average on 5-point scale)

	Participants (n=42)	Dropouts (n=5)	Controls (n=11)	Trade allies (n=17)	Manufacturers (n=8)
Program information	3.9* (0.17)	3.2 (0.37)	4.4* (0.20)	3.8* (0.21)	3.9* (0.40)
Technical advice	3.4* (0.20)	3.2 (0.48)	4.0* (0.48)	2.8 (0.26)	2.2 (0.45)
Incentives for mid Efficiency	3.6* (0.19)	2.2 (0.20)	3.0 (0.63)	3.0 (0.34)	1.6* (0.37)
Incentives for high efficiency	3.8* (0.20)	3.2 (0.58)	4.0* (0.58)	3.5* (0.35)	4.1* (0.44)
Eligible equipment	3.4* (0.19)	2.4 (0.51)	3.6* (0.53)	3.3* (0.32)	3.5* (0.50)
Application procedure	3.6* (0.18)	2.6 (0.24)	3.9* (0.55)	3.3* (0.21)	2.6 (0.81)
Overall program	3.8* (0.20)	3.0 (0.45)	3.6* (0.44)	3.4* (0.26)	2.9 (0.30)

Note: Standard errors are shown below the average scores in parentheses, and an asterisk indicates that the average score is different from 2.5 at the 95% confidence level.

In overall terms, the only group for which satisfaction levels were not generally significantly greater than 2.5 were drop outs. This may be largely due to the fact that drop outs who began the program but were not able to obtain an incentive were dissatisfied with the program.

5.2 Program Barriers and Opportunities

Stakeholders were asked a series of questions about the importance of factors encouraging the installation of efficient boilers. These factors, which in the context of market transformation can be viewed as program opportunities, included the following:

- Information on efficient boilers from BC Gas.
- Recommendations from engineering consultants, contractors or manufacturers' representatives.
- Lower energy operating costs.
- Higher boiler efficiency.
- Appropriate boiler sizing.
- Availability of financial incentives through the program.
- Reduced impact on environment.

Exhibit 5.4 provides information on stakeholders' ratings of the importance of these factors on encouraging the installation of efficient boilers using a five-point scale where one is not at all important and five is very important, with the standard errors in parentheses. It is useful to examine the significance of the average importance scores under the assumption that typical factor importance would result in an average score of 2.5, so that a score significantly different from 2.5, at the 95% confidence level, is potentially of interest. Values that are statistically different from 2.5 are indicated by an asterisk.

Importance of information on efficient boilers from BC Gas is rated highly by customers but lower by other stakeholders: 3.8 by participants, 4.3 by dropouts, 3.7 by controls, 2.6 by trade allies and 3.0 by manufacturers and is significant for three groups. In a future program, increased communication with trade allies and manufacturers' representatives on information being provided to consumers would be useful, since the numbers for trade allies and manufacturers were low.

Importance of recommendations from trade allies (engineering consultants, contractors or manufacturers' representatives) is perhaps surprisingly rated lower by trade allies at 3.6 than by participants at 4.4, dropouts at 4.4, controls at 3.9, and manufacturers at 4.0 and is significant for all five groups. Engineering consultants, contractors, and manufacturers representatives are major influencers on customers' decisions on choice of boiler system.

Importance of lower energy operating costs is clearly the critical factor at 4.8 for participants, 5.0 for dropouts, 4.6 for controls, 4.5 for trade allies an 4.4 for manufacturers and is significant for five groups. Lower energy costs are the most important factor influencing customers to install mid efficiency and high efficiency boilers.

Importance of higher boiler efficiency is slightly lower at 4.3 for participants. 4.7 for dropouts, 4.4 for controls, 3.9 for trade allies and 4.1 for manufacturers and is significant for five groups. This factor is just less important than lower energy operating costs as an influencer of boiler choice.

Importance of appropriate boiler sizing is more important for customers than for other stakeholders at 4.6 for participants, 4.7 for dropouts, 4.4 for controls, 3.7 for trade allies and 4.1 for manufacturers and is significant for five groups. Appropriate boiler sizing is the second most important factor influencing customers to install mid efficiency and high efficiency boilers.

Importance of availability of financial incentives through the program is generally rated at 4.0 or more at 4.4 for participants, 4.4 for dropouts, 3.9 for controls, 4.6 for trade allies and 4.2 for manufacturers and is significant for five groups. For customers, availability of financial incentives through the program is a less important influencer of boiler choice than lower energy operating costs, higher boiler efficiency or appropriate boiler sizing.

Importance of reduced impact on the environment is quite mixed at 4.3 for participants, 4.1 for dropouts, 3.8 for controls, 3.1 for trade allies and 2.2 for manufacturers and is significant for four groups. Reduced impact is important to customers but less important to trade allies and manufacturers as an influencer.

Exhibit 5.4. Program Opportunities (average on 5-point scale)

	Participants (n=62)	Dropouts (n=7)	Controls (n=25)	Trade allies (n=19)	Manufacturers (n=8)
Information from BC Gas	3.8* (0.20)	4.3* (0.18)	3.7* (0.29)	2.6 (0.31)	3.0 (0.44)
Recommendations from trade allies	4.4* (0.14)	4.4* (0.30)	3.9* (0.24)	3.6* (0.28)	4.0* (0.19)
Lower energy operating costs	4.8* (0.06)	5.0* (0.00)	4.6* (0.21)	4.5* (0.17)	4.4* (0.26)
Higher boiler efficiency	4.3* (0.13)	4.7* (0.18)	4.4* (0.22)	3.9* (0.26)	4.1* (0.30)
Appropriate boiler size	4.6* (0.12)	4.7* (0.18)	4.4* (0.21)	3.7* (0.30)	4.1* (0.35)
Financial incentives	4.4* (0.13)	4.4* (0.30)	3.9* (0.25)	4.6* (0.14)	4.2* (0.31)
Reduced impact on environment	4.3* (0.14)	4.1* (0.14)	3.8* (0.24)	3.1* (0.30)	2.2 (0.31)

Note: Standard errors are shown below the average scores in parentheses, and an asterisk indicates that the average score is different from 2.5 at the 95% confidence level.

Stakeholders were also asked a series of questions about the importance of factors discouraging the installation of efficient boilers. These factors included:

- Limited knowledge of efficient boilers
- Uncertainty that savings will be realized
- Limited consultant or contractor experience with efficient boilers
- High equipment costs for efficient boilers, excluding installation costs
- High installation costs for efficient boilers excluding equipment costs
- Concerns about reliability of efficient boiler system
- Concerns about operating and maintenance of efficient boiler systems.

Exhibit 5.5 provides information on stakeholders' ratings of the importance of these factors on discouraging the installation of energy efficient boilers using a five-point scale where one is not at all important and five is very important. It is again useful to examine the significance of the average importance scores under the assumption that typical factor importance would result in an average score of 2.5, so that a score significantly different from 2.5, at the 95% confidence level, is potentially of interest and is indicated by an asterisk.

Importance of limited customer knowledge is quite high at 3.5 for participants, 4.1 for dropout, 3.3 for controls, 3.0 for trade allies and 3.6 for manufacturers and is significant for five groups. From the perspectives of customers, this finding suggests that limited knowledge of efficient boilers is a significant constraint on take-up of the higher efficiency technologies, especially for those customers who showed initial interest but did not complete the program through to the receipt of an incentive. Perhaps this could be addressed through a more aggressive education and promotion campaign.

Importance of uncertainty that savings would be realized is again quite high at 3.9 for participants, 3.6 for dropouts, 3.7 for controls, 3.2 for trade allies and 3.9 for manufacturers and is significant for five groups. Here, detailed case studies on how mid efficiency and especially high efficiency boilers have performed would be useful in overcoming this fairly widespread concern.

Importance of limited consultant or contractor experience with efficient boilers is viewed as less of a barrier by customers than it is by other stakeholders at 3.8 for participants, 3.7 for dropouts, 3.1 for controls, 4.5 for trade allies and 4.1 for manufacturers and is significant for four groups. It is particularly telling that this is rated by trade allies as a very important factor discouraging the installation of mid efficiency and high efficiency boilers. Perhaps additional liaison with leading consulting engineering firms would help to suggest solutions, of which additional training activities could be a major part.

Importance of high equipment costs of efficient boilers is rated as 3.9 for participants, 4.1 for dropouts, 3.7 for controls, 3.4 for trade allies and 3.4 for manufacturers and is significant for the five groups. High equipment costs were the second most important barrier for drop outs and controls.

Importance of high installation costs is generally less important than high equipment costs at 3.8 for participants, 3.8 for dropouts, 4.0 for controls, 3.4 for trade allies and 3.4 for manufacturers and is significant for four groups. Since installation costs are at least partly driven by contractor familiarity with the specific features of mid efficiency and high efficiency boiler technology, the implementation of a broader training program would help alleviate this constraint.

Importance of concerns about reliability of efficient boiler systems is 4.2 for participants, 4.6 for dropouts, 3.5 for controls, 3.3 for trade allies and 3.6 for manufacturers and is significant for five groups. Concerns about reliability are the most important factor discouraging customers from installing mid efficiency and high efficiency boilers.

Importance of maintenance and operating costs of efficient boilers systems is 4.2 for participants, 4.0 for dropouts, 3.5 for controls, 2.6 for trade allies and 3.4 for manufacturers and is significant for three groups. Concerns about operating and maintenance costs were tied with concerns about reliability as the most important barrier for participants.

Exhibit 5.5. Program Barriers (average on 5-point scale)

	Participants (n=62)	Dropouts (n=7)	Controls (n=25)	Trade allies (n=25)	Manufacturers (n=8)
Limited knowledge	3.5* (0.23)	4.1* (0.26)	3.3* (0.33)	3.0* (0.23)	3.6* (0.42)
Uncertain savings	3.9* (0.17)	3.6* (0.30)	3.7* (0.30)	3.2* (0.31)	3.9* (0.51)
Limited experience contractor/consultant	3.8* (0.20)	3.7* (0.29)	3.1 (0.32)	4.5* (0.20)	4.1* (0.30)
High equipment costs	3.9* (0.16)	4.1* (0.46)	3.7* (0.30)	3.4* (0.29)	4.6* (0.26)
High installation costs	3.8* (0.14)	3.8* (0.19)	4.0* (0.44)	3.4* (0.30)	3.4 (0.65)
Concerns about reliability	4.2* (0.16)	4.6* (0.20)	3.5* (0.30)	3.3* (0.33)	3.6* (0.46)
Concerns about O&M costs	4.2* (0.17)	4.0* (0.38)	3.5* (0.31)	2.6 (0.31)	3.4 (0.53)

Note: Standard errors are shown below the average scores in parentheses, and an asterisk indicates that the average score is different from 2.5 at the 95% confidence level.

The findings from the program research, the literature and website review and the surveys are synthesized in the form of a SWOT (strengths, weaknesses, opportunities, threats) analysis in Exhibit 5.6. Several aspects stand out from this overall analysis. First, the key strength of the Efficient Boiler Program is the promise of lower energy consumption and energy costs. In addition, BC Gas' knowledge and reputation are available to help effectively sell the technology to customers. A further strength is that the Efficient Boiler Program offers environmental benefits, by reducing GHG emissions.

Second, the key weakness or barrier to increased use of higher efficiency boilers is still their higher incremental capital costs, despite the progress made through the program. Additional weaknesses or barriers include limited customer and trade ally knowledge of the technology and of the advantages of higher efficiency boilers as well as limited engineering consultant and contractor capability to effectively design and implement projects

Third, there is significant opportunity for increased penetration of higher efficiency boilers in British Columbia, since the extent of market penetration is still relatively low. In addition, the program reduces future peak-day loads and offers good potential for load retention especially in the Interior.

Fourth, technical issues surrounding selection, installation and operation of efficient systems are the main threat to transforming the boiler market. Finally, there is a growing awareness and interest in ground source heat pumps and electric heat that threaten BC Gas' core market

Exhibit 5.6. SWOT Analysis

	Current	Future
Positive	Strength: *Key strength of the technology is promise of lower energy consumption and energy costs*BC Gas' knowledge and reputation are available to help sell the technology *Boiler program offers environmental benefits by reducing GHG emissions as gas consumption is reduced	Opportunities: *Penetration of efficient boilers in BC is still relatively low with significant future market potential *Reduce future peak day loads and consequent BC Gas capital requirements *Program offers good potential for load retention especially in the Interior
Negative	Weaknesses: *Limited customer and trade ally knowledge of technology/advantages of higher efficiency boilers *High incremental capital costs of efficient systems key barrier to participation *Limited engineering consultant and contractor capability to effectively design and implement projects	Threats: *Improperly designed or installed systems may fail prematurely *Condensing boilers require sophistication monitoring/management capabilities *There is a growing awareness and interest in air and ground source heat pumps and electric heat that could erode BC Gas' core market

5.3 Market Transformation

In market transformation evaluations, a key issue is the impact of the program on sale and market shares for standard and efficient products. The underlying program logic is that product subsidies, education and marketing will lead to: (1) increased market share and sales for the efficient product; and (2) economies of scale that will lead to further relative price decreases for the efficient product and thus eliminate the need for future subsidies and supportive marketing activities.

The process evaluation provided estimates of the number of boilers sold at various efficiency levels, which further allowed the shares of standard efficiency, mid-efficiency and high efficiency boilers to be calculated for 1995. For the current survey, manufacturers were asked to estimate the size of the boiler market and the shares of standard efficiency, mid-efficiency and high efficiency boilers in 2001.

Exhibit 5.7 compares the results of these estimates for 1995 and 2001. The market share of high efficiency boilers increased from 7% to 10%, the market share of mid efficiency boilers decreased from 23% to 21% and the market share of standard efficiency boilers decreased from 70% to 69% between 1995 and 2001. This is consistent with a gradual move towards a more efficient boiler market. In particular, the 10% share for high efficiency boilers is substantially higher than the 2% share high efficiency boilers in the United States.

Exhibit 5.7. Estimated Boiler Sales by Efficiency Level

Efficiency level	Number of boilers sold		Share of boilers sold	
	1995	2001	1995	2001
Standard	1050	1555	70%	69%
Mid	345	470	23%	21%
High	105	225	7%	10%
Total	1500	2250	100%	100%

Trade allies and manufacturers were asked a further series of questions that were used to estimate the percentage increase in boiler prices by boiler type for the period 1995 to 2002. Although some respondents felt that prices for all categories of boilers had decreased since 1995, most respondents felt that prices had increased for all efficiency levels. The estimates of percentage changes in standard efficiency boiler prices was 4.1%; for mid-efficiency boiler prices 6.8%; and for high efficiency boiler was 7.0%.

Exhibit 5.8. Estimated Percentage Increase in Boiler Prices by Efficiency Levels

Efficiency level	Manufacturers and trade allies (n = 27)
Standard	4.1%
Mid	6.8%
High	7.0%

5.4 Free Riders and Free Drivers

Free riders are customers who received a financial incentive through the program but would have installed a mid efficiency or high efficiency boiler in the absence of the program. The issue of the extent of free riders thus directly addresses the study objective of assessing the correct attribution of measure installations.

If the respondent had received a financial incentive through the Efficient Boiler Program, the respondent was asked how important the incentive was in the decision to install an efficient boiler. A weighted score was then calculated using the following weights: score of five has weight of 1.00, score of four has weight of 0.75, score of three has weight of 0.50, score of two has weight of 0.25 and score of one has weight of 0.00. The weighted average of the importance scores is the quantity (one minus the free rider rate) of 0.82 for subsequent analysis. The implicit free rider rate of 0.18 compares favourably with other evaluations.

Exhibit 5.9. Free Rider Estimates

	Very important (5)	(4)	(3)	(2)	Very un-important (1)	Score (1-FR)
Weight	1.00	0.75	0.50	0.25	0.00	
Share	0.57	0.18	0.19	0.03	0.03	0.82

Free drivers or spill over refers to customers who installed either a more efficient boiler because of the program without receiving an incentive or customers who undertook additional energy savings measures as an indirect result of the program.

Respondents were also asked how important the incentive was in the decision to undertake other retrofit measures that affected natural gas use. These measures are shown below. A weighted score was then calculated using the following weights: score of five has a weight of 1.00, score of four has a weight of 0.75, score of three has a weight of 0.50, score of two has a weight of 0.25 and score of one has a weight of 0.00. The weighted average of the importance scores is the spill over rate of 0.58. It should be noted that this spill over rate is not applied in the analysis because the billing analysis is automatically picking up the spill over effect since we use whole account billing information.

Exhibit 5.10. Spill Over Estimate

	Very important (5)	(4)	(3)	(2)	Very un-important (1)	Score (spill over rate)
Weight	1.00	0.75	0.50	0.25	0.00	-
Share	0.32	0.18	0.05	0.41	0.05	0.58

5.5 Boiler Systems and Natural Gas Use

Four segments account for the bulk of program activity. In decreasing order of importance these are institutional (including schools, hospitals, and nursing homes), hospitality (including hotels, motels, restaurants), office and multi-family residential. The institutional segment is the most important for the participant and dropout groups while the hospitality segment is the most important for the control group.

Exhibit 5.11. Building Type (share)

	Participants (n=62)	Drop outs (n=7)	Controls (n=25)
Multi-family residential	10%	14%	24%
Office	19%	14%	12%
Institutional	39%	57%	24%
Manufacturing/processing	2%	-	12%
Wholesale	-	-	-
Retail		-	4%
Hospitality	29%	14%	28%

A number of characteristics of buildings and boiler plants are shown in Exhibit 5.12. Note that standard errors for variables are shown in parentheses. Most buildings have more than one boiler plant (participants having 2.2 plants, dropouts 1.7 and comparison 1.5) and more than one boiler per plant. For those buildings with multiple boilers, participants have about twice as many standard boilers, mid efficiency boilers and high efficiency boilers as do control buildings.

Average capacity of boilers systems is 4.2 million Btuh for participants, 4.7 million Btuh for dropouts and 7.6 million Btuh for control buildings. Control buildings are on average the largest (147,000 square feet) followed by participants (121,000 square feet) and dropouts (87,000 square feet).

A useful indicator of energy intensity is given by Btuh per square foot: participant buildings have an energy intensity of 35 Btuh per square foot; with drop outs at 54 Btuh per square foot; and controls at 52 Btuh per square foot. In other words, the installed energy intensity of participants is below that of drop outs or controls.

Exhibit 5.12. Characteristics of Boiler Plants and Buildings

	Participants (n=62)	Drop outs (n=7)	Controls (n=25)
Number of natural gas boiler plants	2.2 (0.82)	1.7 (0.36)	1.5 (0.20)
Number of natural gas boilers	5.1 (2.1)	3.0 (0.38)	2.5 (0.31)
Number of standard efficiency (multiple boiler systems)	2.9 (2.2)	0.50 (0.34)	1.5 (0.46)
Number of mid efficiency (multiple boiler systems)	1.8 (0.71)	1.2 (0.54)	1.0 (0.34)
Number of high efficiency (multiple boiler systems)	1.9 (0.25)	1.2 (0.75)	0.60 (0.29)
Heated building area (square feet)	121,000 (18,400)	87,000 (27,400)	147,000 (45,900)
Apparent energy intensity (Btuh per square foot)	35	54	52

Note: Standard errors are shown below the average scores in parentheses.

Changes to boiler plants and buildings are shown in Exhibit 5.13. About 10% of participants and 8% of controls experienced changes in heated floor space from 1994 onwards with average increases in heated floor space of 2,000 square feet for participants and 6,000 square feet for controls. This suggests an average change in heated area of 200 square feet for participants, zero square feet for drop outs and 480 square feet for controls, or less than 0.3%. These numbers on changes in heated floor space are small enough that they can be ignored in our analysis.

Exhibit 5.13 also shows further details of installed boiler systems. The average number of replacement boilers installed was 1.02 for program participants, 0.86 for drop outs and 0.96 for controls. The average age of boilers replaced varied substantially across groups at about 27 years for program participants, 38 years for drop outs and 26 years for controls.

Exhibit 5.13. Changes to Boiler Plants and Buildings

	Participants (n=62)	Drop outs (n=7)	Controls (n=25)
Change in heated area (share yes)	10%	-	8%
Average increase in heated area if change happened (square feet)	2000	-	6000
Number of boilers replaced since December 1994	1.02	0.86	0.96
Age of previous boiler replaced (years)	27.4	37.7	25.6

Reasons for boiler replacement are shown in Exhibit 5.14, with multiple responses permitted. For participants, the main reasons for boiler replacement were to improve boiler efficiency, life cycle replacement, because of anticipated boiler failure, and to reduce energy costs. For dropouts, the main reasons for boiler replacement were to improve boiler efficiency, as part of a mechanical retrofit and as part of a regular life cycle replacement program. For controls, the main reasons for boiler replacement were as part of a lifecycle replacement, to improve boiler efficiency and because of anticipated boiler failure.

Exhibit 5.14. Reasons for Boiler Replacement (Among those who replaced boilers)

	Participants (n=26)	Drop outs (n=3)	Controls (n=13)
Improve boiler efficiency	38%	67%	39%
Life cycle replacement	27%	33%	54%
Boiler failure	19%	-	23%
Anticipated boiler failure	23%	-	-
Reduce energy costs	23%	-	-
Mechanical retrofit	-	67%	-
Other/DK/NR	19%	-	8%

Many respondents undertook additional measures that affected natural gas consumption at the time of boiler replacement. The most popular of these are upgrade to energy system controls, upgrade to piping systems and upgrade to domestic hot water systems. Less important upgrades include adding or removing the domestic hot water load to the boiler plant and envelope changes.

Exhibit 5.15. Measures Undertaken at Time of Boiler Replacement

	Participants (n=62)	Drop outs (n=7)	Controls (n=25)
Upgrade to energy system controls	32%	28%	12%
Upgrade to piping system	26%	14%	20%
Upgrade to domestic hot water (DHW)	21%	14%	32%
DHW added to boiler plant	15%	-	8%
DHW removed from boiler plant	3%	-	8%
Upgrade to building envelope	3%	-	4%
Other	5%	-	4%

Boiler system costs are shown in Exhibit 5.16. Total boiler costs per system are about $480,000 for participants, $420,000 for dropouts, and $320,000 for controls, with standard errors shown in parentheses. Incremental costs are on the order of $160,000 for participants and $100,000 for dropouts over the costs for controls. The share of boiler equipment in total costs is just over one-half for participants and dropouts but much higher at nearly 70% for controls.

Another way to examine costs is by considering boiler system costs, including installation costs, on a per square foot of heated area basis. Total boiler costs including installation costs are $3.98 per square foot for participants, $4.85 for drop outs and $2.18 for controls. This suggests that incremental unit costs are on the order of $1.80 per square foot for participants and $2.67 for drop outs.

Exhibit 5.16. Boiler Costs

	Participants (n=62)	Drop outs (n=7)	Controls (n=25)
Total boiler system costs including installation	$482,000 ($203,000)	$422,000 ($139,000)	$321,000 ($127,000)
Per square foot boiler system costs including installation	$3.98 per square foot	$4.85 per square foot	$2.18 per square foot
Share of boiler equipment (%)	56% (5.3%)	52% (13.6%)	68% (9.3%)
Share of piping and ancillary (%)	44% (5.3%)	48% (13.65)	32% (9.3%)

Note: Standard errors are shown below the average scores in parentheses.
Boiler maintenance costs are shown in Exhibit 5.17. Annual maintenance costs, excluding fuel costs, are $5,900 for participants, $4,600 for dropouts and $6,400 for controls. On a unit basis, annual maintenance costs are $0.049 per square foot for participants, $0.053 per square foot for drop outs and $0.044 per square foot for controls. The share of respondents who have periodic boiler maintenance is 81% for participants, 100% for drop outs and 92% for controls.

Exhibit 5.17. Boiler Maintenance

	Participants (n=62)	Drop outs (n=7)	Controls (n=25)
Total annual maintenance costs for current boiler system	$5,900 ($1,300)	$4,600 ($1,500)	$6,400 ($2,700)
Per square foot annual maintenance costs for current boiler system	$0.049 ($0.011)	$0.053 ($0.017)	$0.044 ($0.019)
Share who have periodic boiler system inspection and adjustments	81%	100%	92%
Share who have this done by building staff	66%	71%	48%
Share who have this done by contractor	36%	43%	61%
Share who have this done by other	6%	-	13%

Note: Standard errors are shown below prices in parentheses.

Customers were asked to assess the reliability of their boiler systems on a five-point scale where one is poor and five is excellent. Their average assessments are shown in Exhibit 5.18. The ratings are 3.8 for participants, 4.1 for dropouts and 4.2 for controls, and these ratings are all significantly different from 2.5.

Exhibit 5.18. Customer Assessment of Reliability of Boiler System (average on a five-point scale)

	Participants (n=62)	Dropouts (n=7)	Controls (n=25)
Mean	3.8* (0.16)	4.1* (0.26)	4.2* (0.22)

Note: Standard errors are shown below the average scores in parentheses, and an asterisk indicates that the average score is different from 2.5 at the 95%

confidence level.

Trade allies and manufacturers were also asked to assess the reliability of boiler systems. For standard and mid efficiency boilers, their assessments were similar to those of customers. But the reliability of high efficiency boilers was assessed to be lower at 3.3 by trade allies and 2.8 for manufacturers.

Exhibit 5.19. Trade Ally and Manufacturer Assessment of Reliability of Boilers by Efficiency Level (average on a five-point scale)

Efficiency level	Trade ally estimates (n=19)	Manufacturer estimates (n=8)
Standard	3.8* (0.25)	4.2* (0.30)
Mid	4.1* (0.18)	3.9* (0.35)
High	3.3* (0.26)	2.8 (0.48)

Note: Standard errors are shown below the average scores in parentheses, and an asterisk indicates that the average score is different from 2.5 at the 95% confidence level.

Customers who rated reliability as a 1, 2 or 3 were asked to provide information on problems they have experienced with their boiler systems, as shown in Exhibit 5.20. For participants the main problems were with operating controls, heat exchangers, ignition systems, boiler leaks, condensate and corrosion, and unreliable operation. For dropouts the main problems was with operating controls. For controls the main problems were with unreliable operation, boiler leaks, heat exchangers and condensate.

Exhibit 5.20. Customer Problems with Boiler Systems (Customers who rated reliability as a 1, 2, 3)

	Participants (n=62)	Drop outs (n=7)	Controls (n=25)
Operating controls	8%	14%	-
Noise/vibration	3%	-	-
Fans	-	-	-
Heat exchangers	7%	-	14%
Condensate/corrosion	5%		14%
Ignition systems	6%	-	-
Unreliable operation	5%	-	28%
Boiler leaks	6%	-	28%

Trade allies and manufacturers were asked to compare problems with mid efficiency boilers compared to standard efficiency boilers. The most common problem areas cited by trade allies were operational knowledge and reliability and maintenance issues. The most common problem areas cited by manufacturers were condensate, reliability and maintenance problems.

Exhibit 5.21. Trade Ally and Manufacturer Perceptions of Problems with Mid-efficiency Boiler Systems (compared to standard efficiency)

	Trade ally (n=19)	Manufacturers (n=8)
Operating controls	5%	-
Noise/vibration	5%	-
Fans	-	-
Heat exchangers	5%	-
Condensate/corrosion	-	25%
Ignition systems	-	-
Operational knowledge	16%	-
Reliability/maintenance	10%	25%

Trade allies and manufacturers were also asked to compare problems with high efficiency boilers compared to standard efficiency boilers. The most common areas cited by trade allies were system design, operational design, reliability and maintenance, cost of replacement parts and condensate and component failure. The most common areas cited by manufacturers were reliability and maintenance, component failure and cost for replacement parts.

Exhibit 5.22. Trade Ally and Manufacturer Perceptions of Problems with High Efficiency Boiler Systems (compared to standard efficiency)

	Trade ally (n=19)	Manufacturers (n=8)
Operating controls	16%	-
Noise/vibration	16%	12%
Fans	-	-
Heat exchangers	-	-
Condensate and corrosion	16%	-
Ignition systems	-	-
Operational knowledge	32%	-
Reliability/maintenance	26%	50%
Design of systems	42%	-
Cost for replacement parts	26%	25%
Component failure	26%	38%
Venting	5%	12%

Customers were asked what the uses of natural gas were in their buildings as shown in Exhibit 5.23. The most common natural gas uses for participants, in decreasing order, included space heating, domestic water heating and cooking. The most common natural gas uses for drop outs, in decreasing order, included domestic hot water heating, space heating, pools and spas and cooking. The most common natural gas uses for controls, in decreasing order, are domestic hot water heating, space heating and cooking.

Exhibit 5.23. Natural Gas Use in the Building

	Participants (n=62)	Drop outs (n=7)	Controls (n=25)
Space heating	82%	57%	76%
Domestic hot water heating	68%	100%	92%
Cooking	29%	29%	24%
Clothes drying	14%	14%	12%
Fireplaces	13%	-	12%
Pools and spas	6%	29%	12%

Customers were also asked for the natural gas uses of the boiler as shown in Exhibit 5.24. The most common boiler uses for participants, in decreasing order, included space heating and domestic water heating. The most common boiler uses for drop outs, in decreasing order, included space heating, domestic hot water heating, pools and spas and laundry. The most common boiler uses for controls, in decreasing order, included space heating, domestic hot water, pools and spas and sterilization.

Exhibit 5.24. Natural Gas Use for the Boiler

	Participants (n=51)	Drop outs (n=4)	Controls (n=9)
Space heating	96%	100%	79%
Domestic hot water	41%	75%	68%
Pools and spas	4%	25%	16%
Laundry	2%	25%	-
Heating chemical solutions	-	-	5%
Sterilization	2%	-	16%
Humidification	2%	-	10%
Flood water for zamboni	-	-	5%

5.6 Program Design Considerations

Trade allies and manufacturers were asked which segment a future program, if one were to be introduced, should target. The top four segments for trade allies were office, institutional, multi-family residential and hospitality. The top four segments for manufacturers were hospitality, institutional, multi-family residential and office. These are also the segments where the Efficient Boiler Program had the most success.

Exhibit 5.25. Target Market for A New Program

	Trade ally (n=19)	Manufacturers (n=8)
Office	95%	75%
Institutional	95%	88%
Multi-family residential	79%	88%
Hospitality	79%	100%
Manufacturing/processing	74%	50%
Retail	68%	38%
Wholesale	47%	50%
Schools	5%	25%
Agriculture	5%	-
Resorts	5%	-
Industrial	5%	-
Residential	5%	-
Municipalities	-	12%

All respondents were asked what should be the focus of a new efficient boiler program, if one were initiated, as shown in Exhibit 5.26. Of those stating an opinion, a majority of each group of respondents favoured providing incentives for both mid efficiency and high efficiency boilers. There was a significant subset of each group of respondents that preferred providing incentives for only high efficiency boilers. Few respondents favoured providing incentives for mid efficiency boilers only.

Exhibit 5.26. Focus of a New Program

Efficiency level	Participants (n=62)	Dropouts (n=7)	Controls (n=25)	Trade ally estimates (n=19)	Manufacturer estimates (n=8)
Mid	7%	-	12%	5%	12%
High	23%	29%	36%	21%	38%
Both	42%	71%	48%	68%	50%
DK/NR	29%	-	4%	5%	-

Manufacturers were asked about their views on the economic outlook for the boiler market over the next five years as shown in Exhibit 5.27 (standard errors of growth rates in parentheses). Estimated annual growth rate for the boiler market was 12%. In the absence of a new BC Gas program, the efficient boiler market was expected to grow 20% per year. With a new BC Gas program this increased to 24% per year, not statistically significant given the small sample. Standard errors of the projected growth rates are shown in parentheses.

Exhibit 5.27. Estimated Five-year Growth Rates
for British Columbia Boiler Market

	Manufacturer estimates (n=8)
Baseline annual growth rate of boiler market	12% (3.8%)
Baseline annual growth rate of efficient boiler sales	20% (5.7%)
Boiler growth rate with new BC Gas program	24% (3.2%)

Stakeholders have a wide variety of views on other programs that BC Gas should consider offering to commercial and multi-family residential customers. As shown in Exhibit 5.28, participants suggested envelope measures, education, steam boilers, energy management controls, and roof top heaters. Dropouts suggested envelope measures, alternate energy, roof top heaters, steam boilers and consulting. Controls suggested envelope measures, alternate energy, roof top heaters, steam boilers and consulting.

Exhibit 5.28. Other Programs BC Gas Should Consider Offering

	Participants (n=62)	Dropouts (n=7)	Controls (n=25)	Trade ally (n=19)	Manufacturers (n=8)
Envelope measures	13%	29%	28%	5%	-
Education	11%	-	-	5%	12%
Ground source heat pumps	-	-	-	5%	-
Combine BC Gas/BC Hydro programs	-	-	-	5%	-
Alternate energy	8%	29%	24%	5%	-
Domestic hot water	8%	-	-	5%	12%
Energy controls	10%	-	-	-	12%
Energy Audits	9%	-	4%	-	12%
Roof top heaters	10%	29%	28%	-	12%
Steam Boilers	11%	29%	24%	-	-
Consulting services	8%	29%	24%	-	-

5.7 Program Communications

Respondents were asked to state their most preferred methods of learning about BC Gas energy efficiency programs. For customers, these included direct mail, E-mail, BC Gas website and BC Gas representatives. For trade allies and manufacturers these included direct mail, E-mail and BC Gas representatives.

Exhibit 5.29. Most Preferred Method of Learning about BC Gas Energy Efficiency Programs (share of respondents)

	Participants (n=62)	Dropouts (n=7)	Controls (n=25)	Trade allies (n=19)	Manufacturers (n=8)
Direct mail	16%	29%	36%	16%	12%
E-mail	5%	14%	32%	37%	50%
BC Gas website	6%	29%	-	10%	-
BC Gas representative	14%	14%	12%	11%	25%
Trade journals	5%	-	-	-	-
Manufacturers' literature	8%	-	-	-	-
Engineering consultants	3%	-	-	-	-
TV/radio	-	-	-	-	-
Trade shows	-	-	-	-	-
Mechanical contractors	2%	-	4%	-	-
Newsletter/ Brochures	3%	4%	14%	-	-
Newspaper	1%	2%	4%	-	-
Bill stuffers	1%	-	4%	-	-
BC Gas workshops	5%	-	-	16%	-

Respondents were asked to state their second most preferred methods of learning about BC Gas energy efficiency programs. For customers, these included direct mail, E-mail and BC Gas representatives. For trade allies and manufacturers these included direct mail, BC Gas website and BC Gas representatives.

Exhibit 5.30 Second Most Preferred Method of Learning about BC Gas Efficiency Programs (share of respondents)

	Participants (n=62)	Dropouts (n=7)	Controls (n=25)	Trade allies (n=19)	Manufacturers (n=7)
Direct mail	16%	43%	12%	10%	25%
E-mail	10%	-	12%	-	-
BC Gas website	5%	-	12%	26%	12%
BC Gas representative	10%	-	-	5%	25%
Trade journals	5%	-	-	-	-
Manufacturers' literature	3%	-	-	-	-
Engineering consultants	3%	-	-	-	-
TV/radio	-	-	8%	-	-
Trade shows	-	14%	-	-	12%
Mechanical contractors	2%	-	-	-	-
Newsletter/brochures	-	-	-	11%	-
Newspaper	-	-	-	-	-
Bill stuffers	-	-	-	-	-
BC Gas workshops	2%	14%	12%	10%	12%

6 Impact Analysis

6.1 Technology and Benefits

Normalized weather-adjusted billing data was used to estimate the gross impact of higher efficiency boilers on natural gas consumption by removing the impact of year-to-year changes in weather. The steps involved here were as follows:

- Determine pre and post periods for each account (as appropriate).
- Match natural gas consumption of each billing period to heating degree-days for an appropriate location.
- Regress average daily consumption on average daily heating degree-days.
- Estimate annual normalized consumption as the sum of (365*intercept coefficient) plus (slope coefficient *typical annual heating degree days). This is base load plus weather sensitive load.

For retrofits, gross annual savings were defined as pre-retrofit consumption minus post–retrofit consumption. For new buildings, there is no pre-retrofit building to serve as a baseline. We therefore calculated gross annual savings as control group consumption minus participant consumption. Using survey information, a free rider rate was calculated with net savings then defined as gross savings times one minus the free rider rate.

Exhibit 6.1 shows weather normalized average natural gas consumption for program retrofit participants installing mid efficiency and high efficiency boilers. Standard errors for consumption are the sum of the standard deviations for consumption divided by the square root of the sample sizes. For retrofit participants, pre-retrofit weather normalized natural gas consumption was 12,995.3 GJ per year, post-retrofit weather normalized natural gas consumption was 11,030.6 GJ per year, and there was a decrease in natural gas consumption of 1,964.7 GJ per year. It should be noted that because we are using whole building normalized billing data, this savings number includes both direct savings due to the program and spill over savings, due to other changes or upgrades that were induced by the program including upgrade to building systems and improvements in energy management controls.

Exhibit 6.1 also shows weather normalized equivalent natural gas consumption for program retrofit participants installing mid efficiency and high efficiency boilers but also switched from another space heating fuel. For fuel switching retrofit participants, pre-retrofit weather normalized natural gas consumption was 27,934.7 GJ per year, post-retrofit weather normalized natural gas consumption was 9,419.4 GJ per year, and there was a decrease in natural gas consumption of 18,515.3 GJ per year. It should be noted that engineering estimates were used to convert pre-participation fuel consumption to its natural gas equivalent.

Exhibit 6.1. Weather Normalized Average Consumption for Retrofit Participants (n = 20 same fuel retrofits, n= 3 fuel switch retrofits)

	Consumption (GJ per year)	Standard error (GJ per year)
Pre-retrofit (same)	12,995.3*	5,002.3
Post-retrofit (same)	11,030.6*	4,027.2
Unit savings (same)	-1,964.7*	1,271.7
Pre-retrofit (switch)	27,934.7*	15,221.3
Post-retrofit (switch)	9,419.4*	4,851.2
Unit savings (switch)	-18,515.3*	10,628.8

Note: An asterisk indicates that the entry is different from zero at the 80% confidence level.

Exhibit 6.2 shows weather normalized average natural gas consumption for program new building participants installing mid efficiency and high efficiency boilers. Standard errors for consumption are the sum of the standard deviations for consumption divided by the square root of the sample sizes. For new building participants, weather normalized natural gas consumption was 5,484.7 GJ per year, control group weather normalized average natural gas consumption was 5,888.6 GJ per year, and there was apparent savings in natural gas consumption of 404.3 GJ per year. Again these savings estimates include spill over savings.

Exhibit 6.2. Weather Normalized Average Consumption for New Building Participants (n = 16)

	Consumption (GJ per year)	Standard error (GJ per year)
New Buildings	5,484.7*	1,386.9
Controls	5,888.6*	896.4
Unit Savings	404.3	1,386.9

Note: An asterisk indicates that the entry is different from zero at the 80% confidence level.

For retrofits and for new building participants, unit savings are multiplied by the number of buildings in the class to get gross savings. Net savings are then equal to gross savings times the term one minus the free rider rate (1 – FRR) to provide the estimate of net savings as shown in Exhibit 6.5. Estimated net savings are 128.88 TJ per year for same fuel retrofit participants, 45.55 TJ for fuel switching retrofit participants and 15.91 TJ per year for new building participants, for a total of 190.34 TJ per year. Using an emissions factor of 33.35 tonnes of carbon dioxide per terajoule yields an emissions reduction or carbon dioxide savings total 6.35 kilotonnes as shown in Exhibit 6.5.

Exhibit 6.5. Energy and CO_2 Savings by Category

	Unit savings (GJ)	Number of buildings	Gross savings (TJ)	(1 - FRR)	Net savings (TJ)	CO_2 (ktonnes)
Retrofits (same)	1,964.7	80	157.18	0.82	128.88	4.30
Retrofit (switch)	18,515.3	3	55.55	0.82	45.55	1.52
New buildings	404.3	48	19.41	0.82	15.91	0.53
Total	-	131	232.14	-	190.34	6.35

In order to estimate peak savings, we assume that heating load on any day is proportional to heating degree days for that day, so that in the coldest month (January) the average daily heating load is (annual heating load in GJ)*(monthly share of annual heating degree days for January)*(1/31 days). The change in peak day load is then estimated as the change in average daily load for January. Exhibit 6.6 calculates the weighted peak day heating load share for January using a representative weather station for each zone and the thirty-year typical meteorological year heating degree day shares for January. This is multiplied by net savings to estimate peak day savings. Estimated peak day savings are about 1.047 TJ.

Exhibit 6.6. Peak Day Savings

Zone	Representative weather station	Zone customer share	Peak day heating load share	Weighted peak day heating load share	Peak savings (TJ)
Zone 1	Vancouver	0.244	0.00501	0.00122	-
Zone 2	Burnaby	0.173	0.00511	0.00088	-
Zone 3	Surrey	0.280	0.00510	0.00143	-
Zone 4	Kamloops	0.117	0.00625	0.00073	-
Zone 5	Cranbrook	0.186	0.00667	0.00124	-
Total	-	1.000	-	0.00550	1.047

Engineering estimates of gross savings were made by the program staff for each building participating in the Efficient Boiler Program, based on the size of the building, the planned installation and heating degree days. Exhibit 6.7 calculates a realization rate of 191.5% as the ratio of evaluated savings to engineering estimates. There are three reasons for this high realization rate: first, there are spill over savings from efficient technologies that were induced by the program but did not receive an incentive; second, some facilities use the efficient boiler for water heating which lies outside the program; and, third, savings were very high for facilities that involved a change in space heating fuel.

Exhibit 6.7. Savings Realization Rate

	Gross savings (TJ)
Evaluation Estimates	190.34
Engineering Estimates	99.39
Realization Rate	191.5%

6.2 Participant Costs

Estimating boiler costs is complicated by several factors: variable premiums paid for higher quality boilers; higher costs for stainless steel boilers over regular steel boilers; impact of economies of scale on costs; and differences in the cost shares of purchase price, labour cost and overhead and profit in different installations.

Given these complications, it is useful to consider recent estimates of the Consortium for Energy Efficiency (CEE) on relative costs of atmospheric (standard efficiency), power burner (basically mid efficiency), and full condensing (high efficiency) boilers for a variety of commercial size ranges eligible for the Efficient Boiler program. The cost of a 300 MBH atmospheric boiler is set at 1.0 with price ratios for other configurations as shown in Exhibit 6.8. The CEE study emphasizes that these ratios may not be representative of the broader market (indeed the premium for a power burner boiler in the 300 MBH range seems low for British Columbia), and the study further stresses that the premium for high efficiency boilers may be higher than average, but this study seems to present the best recent information readily available. Two key points emerge: first, there is a large capital cost premium for higher efficiency boilers; and, second, there are substantial economies of scale for larger boilers.

Exhibit 6.8. Ratios of Boiler Prices Compared to 300 MBH Atmospheric Boiler

Boiler type	Boiler size		
	300 MBH	500 MBH	1000 MBH
Atmospheric (standard)	1.0	1.2	1.7
Power burner (mid)	1.2	1.9	2.8
Condensing (high)	3.0	3.6	4.8

Source: CEE (2001). A Market Assessment for Condensing Boilers in Commercial Heating Applications.

If we assume that a 1000 MBH power burner, steel boiler costs $12 per MBH in British Columbia and apply the relative cost ratios from the previous exhibit, we get the estimated boiler costs shown in Exhibit 6.9. Installation costs including labour, overheads and profit could add an additional 30% to 100% to the purchase price depending on the size of the boiler, the complexity of the installation, and the competitiveness of the local market.

Exhibit 6.9. Estimated Boiler Costs
(purchase price excluding installation costs)

Boiler type	Boiler size		
	300 MBH	500 MBH	1000 MBH
Atmospheric	$4,286	$5,143	$7,286
Power burner	$5,143	$8,143	$12,000
Condensing	$12,587	$15,430	$20,573

Based on the information in Exhibit 6.9, we can estimate the incremental costs of atmospheric and condensing boilers over atmospheric boilers as shown in Exhibit 6.10. For comparison purposes, the maximum incentive and the ratio of the maximum incentive to the unweighted average incremental capital cost is shown in Exhibit 6.10. These numbers suggest that the program may be paying on the order of 73% of incremental capital costs for high efficiency boilers, but on the order of 44% of incremental capital costs for mid efficiency boilers. Using program shares of mid efficiency and high efficiency boilers, we estimate that the program is thus paying perhaps 60% of overall incremental capital costs, but this is of course subject to some uncertainty. Participant costs are estimated at $1,996,700.

Exhibit 6.10. Incremental Capital Costs of Power Burner
and Condensing Boilers over Atmospheric per MBH

Boiler type	Boiler size			Unweighted average	Maximum incentive per MBH	Ratio of maximum incentive to unweighted average
	300 MBH	500 MBH	1000 MBH			
Power burner	$2.86	$6.00	$4.71	$4.52	$2.00	44%
Condensing	$27.67	$20.75	$13.29	$20.57	$15.00	73%

7 Conclusions

Conclusion 1. Rationale for the Efficient Boiler Program.

The rationale for the Efficient Boiler program was that by providing potential boiler purchasers with information on the advantages of efficient boiler systems, technical advice and assistance to facilitate decision making, and financial incentives to reduce the pay back period that larger numbers of more efficient boilers would be installed. In support of this rationale, the program undertook four main activities: (a) program development; (b) program marketing; (c) technical advice and support; (d) financial incentives. Review of the program and analysis of the survey results suggest that there are valid and plausible linkages among inputs, outputs, purpose and goal for each of the program activities. The Efficient Boiler Program has a valid and persuasive rationale: the basic design involving targeted incentives to reduce financial barriers and build a critical mass of activity is sound, and the specific levels of incentives chosen for mid efficiency and high efficiency boiler systems are appropriate.

Conclusion 2. Examine Customer Awareness and Satisfaction.

Sources of program awareness vary substantially by respondent group, reflecting the fact that different clients use a variety of information channels. The most important sources are BC Gas representatives, engineering consultants and mechanical contractors, word of mouth and advertising. Respondents were asked how satisfied they were with various program components using a five-point scale where one is not at all satisfied and five is very satisfied. Satisfaction with information on the Efficient Boiler program, with the level of incentives offered for high efficiency boilers and with the overall program are generally high. Satisfaction with technical advice and assistance on boiler selection, with the level of incentives offered for mid-efficiency boilers, with the range of equipment eligible for an incentive and with the application procedure are generally lower, but are still reasonably high. Awareness of and satisfaction with the Efficient Boiler Program are at significant levels.

Conclusion 3. Identify Opportunities for Improved Customer Communications.

Respondents were asked to state their most preferred methods of learning about BC Gas energy efficiency programs. For customers, these included direct mail, E-mail, BC Gas website and BC Gas representatives. For trade allies and manufacturers these included direct mail, E-mail and BC Gas representatives. Respondents were asked to state their second most preferred methods of learning about BC Gas energy efficiency programs. For customers, these included direct mail, E-mail and BC Gas representatives. For trade allies and manufacturers these included direct mail, BC Gas website and BC Gas representatives. More aggressive use of targeted program communications would be useful in a subsequent program.

Conclusion 4. Identify and Examine Program Barriers and Opportunities.

All respondents were asked a series of questions about the importance of factors encouraging the installation of efficient boilers. Respondents were asked a series of questions about the importance of factors encouraging the installation of efficient boilers. The following program opportunities were statistically significant in terms of importance for all groups: recommendations from trade allies; lower energy operating costs; higher boiler efficiency; appropriate boiler sizing; and financial incentives through the program. The following program barriers were statistically significant in terms of importance for all groups: limited knowledge of efficient boilers; uncertainty that savings will be realized; high equipment costs for efficient boilers; high installation costs for efficient boilers; and concerns about reliability of efficient boiler system. Bringing these factors together, the program has done a credible job of leveraging opportunities and reducing barriers to the installation of mid efficiency and high efficiency boilers.

Conclusion 5. Assess the State of Market Transformation.

The process evaluation provided estimates of the number of boilers sold at various efficiency levels, which further allowed the shares of standard efficiency, mid efficiency and high efficiency boilers to be calculated for 1995. For the current survey, manufacturers were asked to estimate the size of the boiler market and the shares of standard efficiency, mid-efficiency and high efficiency boilers in 2001. The market share of high efficiency boilers increased from 7% to 10%, the market share of mid efficiency boilers decreased from 23% to 21%, and the market share of standard efficiency boilers decreased from 70% to 69% between 1995 and 2001. This is consistent with a gradual move towards a more efficient boiler market. In particular, the 10% share for high efficiency boilers is substantially higher than the 2% share for high efficiency boilers in the United States. However, it should be noted that the sample sizes in this study are relatively small.

Conclusion 6. Assess Free Riders and Free Drivers.

Free riders are customers who received a financial incentive through the program but would have installed a mid efficiency or high efficiency boiler in the absence of the program. If the respondent had received a financial incentive through the Efficient Boiler Program, the respondent was asked how important the incentive was in the decision to install an efficient boiler and a weighted score was then calculated to produce a free rider rate of 0.18. The implicit free rider rate of 0.18 compares favourably with other evaluations. Free drivers or spill over refers to customers who installed either a more efficient boiler because of the program without receiving an incentive or customers who undertook additional energy savings measures as an indirect result of the program. Participants were asked how important the incentive was in the decision to undertake other retrofit measures that affected natural gas use and a spill over rate of 0.58 calculated. The methodology used in the impact analysis captures both free rider and spill over impacts.

Conclusion 7. Assess Program Experience including Maintenance and Reliability.

Main reasons for boiler replacement were to improve boiler efficiency, because of anticipated boiler failure, to reduce energy costs, as part of a mechanical retrofit and as part of a regular life cycle replacement program. Customers were asked to assess the reliability of their boiler systems on a five-point scale where one is poor and five is excellent. Their average ratings were 3.8 for participants, 4.1 for drop outs and 4.2 for controls. This suggests that customer impressions of the relatively low reliability of efficient boilers systems remain a constraint on more widespread adoption of efficient boilers.

Conclusion 8. Estimate Gross and Net Natural Gas Savings.

Normalized weather-adjusted billing data was used to estimate the gross impact of higher efficiency boilers on natural gas consumption. For retrofits, savings were defined as pre-retrofit consumption minus post–retrofit consumption. For new buildings, there is no pre-retrofit building to serve as a baseline, so we calculated gross annual savings as control group consumption minus participant consumption. Using survey information, a free rider rate was calculated with net savings then defined as gross savings times one minus the free rider rate. Estimated net savings, inclusive of spill over, are 174.43 TJ per year for retrofit participants and 15.91 TJ per year for new building participants for a total of 190.34 TJ per year. Estimated peak day savings are about 1.047 TJ. Carbon dioxide reductions are about 6.35 kilotonnes per year.

Conclusion 9. Identify Customer Costs.

Analysis of cost information indicates that the program may be paying about 73% of incremental costs for high efficiency boilers, but about 44% incremental costs for mid efficiency boilers. Participant costs are estimated at $1,997,000.

Conclusion 10. Determine customer needs for a new program.

Trade allies and manufacturers were asked which segment a future program, if one were to be introduced, should target. The top four segments for trade allies and manufacturers were office, institutional, multi-family residential and hospitality. Stakeholders suggested that the program could include envelope measures, alternate energy, steam boilers, energy management controls, roof top heaters and domestic hot water.

8 Recommendations

Recommendation 1.

Natural gas markets have experienced a high degree of price volatility over the past several years, and some experts believe that this price volatility may be an ongoing characteristic of the natural gas market in North America. A high degree of price volatility has negative impacts on many of BC Gas's commercial and institutional customers, particularly those who have limited ability to hedge against higher prices. Since natural gas prices tend to be particularly high during the space heating season, measures to reduce space heating loads of commercial and institutional customers can be particularly useful in helping to shield these customers from the adverse impacts of natural gas price fluctuations.

We therefore recommend that BC Gas support a renewed Efficient Boiler Program as a means of providing value to BC Gas' 70,000 business customers.

Recommendation 2.

From a utility perspective, demand side management programs have two potential benefits. First, if the marginal cost of increased supply is greater than the marginal benefit of increased sales, the utility is financially better off if it can postpone or avoid increased sales. This situation is most likely to apply for an end use such as space heating that has a high degree of coincidence with system peak, since meeting a highly peak coincident marginal load requires costly distribution investments. Second, many customers have diversified loads such as water heating, drying and cooking that help to keep rates down.

We therefore recommend that a new commercial boiler program include both strategic conservation and load retention as utility benefits of the program.

Recommendation 3.

The Efficient Boiler Program has had considerable success in capturing selected market segments where opportunities in terms of customer knowledge, access to capital and reasonable pay back periods are present. Other segments have been more difficult to capture because of the presence of informational, financial or technical barriers. Based on survey information and a review of the relevant literature, the best opportunities for a new program are in the institutional, office and multifamily residential sectors. In addition, new buildings are a critical sector for a new program, particularly for high efficiency or condensing boilers, and are also socially important because once opportunities for energy efficient investment are lost, major systems may not be upgraded for twenty years or more.

We therefore recommend that a future program target key sectors such as institutional, offices and multifamily residential to build a critical mass of activity, and also target, in particular, new buildings to reduce lost opportunities.

Recommendation 4.

This evaluation study has found that trade allies play a key role in determining the choice of boiler system in both new buildings and retrofits. Engineers, manufacturers representatives and architects are important sources of knowledge and expertise for developers, property owners and building managers who often lack detailed knowledge of the advantages and disadvantages of alternative boiler systems. Although many trade allies have good knowledge and extensive experience with mid efficiency and high efficiency boiler systems, other trade allies lack adequate familiarity with, and knowledge of, these efficient technologies. This is a significant barrier to the widespread technology of higher efficiency boiler systems, especially for condensing boilers.

We therefore recommend that a new program build on relationships with trade allies to strengthen promotional efforts, increase program awareness and improve participation rates.

Recommendation 5.

This evaluation study has also found that while many consumers are knowledgeable about higher efficiency boiler systems, the level of knowledge of other consumers on efficient boiler systems is not adequate. This reduces their ability to make informed decisions on boiler system choice. These less informed consumers lack, in particular, appropriate information on the cost and reliability of efficient boiler systems. They may also have inadequate knowledge of how to maintain and manage efficient boiler systems.

We therefore recommend that a new program provide education and training for customers, possibly focusing on the BC Gas website as a tool, and provide technical advice and assistance for engineering consultants and contractors.

9 References and Works Consulted

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Final Report

2002 Residential Heating System Upgrade Program Evaluation

Prepared for: Terasen Gas

Prepared by:

Habart & Associates Consulting Inc.

October 2003

Table of Contents

i. Executive Summary

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. This incentive was combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers. For the 2002 program, the furnace or boiler had to be purchased from August 1, 2002 to November 30, 2002. Participants received a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada. During this time period 2,785 people participated in the program, almost double the number who had participated in the 2001 program.

The objective of this study was to provide an impact, process and market evaluation of the 2002 program. Following the initial team meeting and review of the limited available research on efficient furnaces, eight critical issues emerged:

- Examine the Efficient Furnace Program, with a view to assessing the rationale for the program.
- Examine the level of customer and trade ally awareness of the furnace technology and the program process.
- Examine the level of customer and trade ally satisfaction with both the furnace technology and the program process.
- Identify and examine program barriers and program opportunities.
- Assess the impact of advertising and promotion activity, including the NRCan funded additional advertising.
- Assess the impact of the program on sales and market share of high efficiency furnaces.
- Assess the impact of the program on prices of high efficiency furnaces.
- Assess the impact of program on energy savings and peak demand due to reduced natural gas consumption.
- Assess the impact of the program on carbon dioxide emissions due to reduced natural gas consumption.

Given the wide scope of these issues, a number of data sources and methods were used in this study. Telephone interviews were conducted with approximately 100 participants and 100 non-participants[1] as well as 20 trade allies who had participated in the program. The survey data was combined with information from Terasen Gas' program data bases to provide answers to the eight issues noted above. In this report, the free rider rate was calculated based on participants' response to questions about the importance of the program in their decision to replace the furnace, and the impact numbers were developed based on engineering estimates. Once sufficient billing data is available, the impact estimates will be re-developed based on the billing data, and the free rider estimates will be refined using discrete choice methods. This analysis will

[1] It should be noted that, for the purpose of this study, non-participants were defined as people who purchased a furnace, but who did not participate in the Terasen Gas program as this approach was felt to provide more valuable information on the state of the furnace market than using a general population recruit.

be done in the fall of 2004.

The results of the study are as follows:

Program rationale:
A detailed review of the program logic (using the Results Based Management concept of input-output-outcome-impact) indicates that there are strong and plausible linkages for each part of the chain, confirming the logic of the program design and rationale for the furnace.

Customer and trade ally awareness:
Ninety-one percent of participant households reported awareness of the program while only 41% of non-participants reported awareness. All trade allies surveyed were aware. This suggests that a future program should focus on building awareness among potential participants.

Customer and trade ally satisfaction:
Satisfaction was measured on a five point scale. Satisfaction levels for participants were above 3.8 for all program components, and were lowest for: information about efficient furnaces, types of furnaces available for rebate and the amount of the rebate. Among non-participants, the major concerns were the time period for the incentive, the types of furnaces available and amount of rebate. All other components scored 4 or above.

Program barriers and opportunities:
For customers who had purchased a standard efficiency furnace, the most common reasons were that the high efficiency furnace was too expensive, the contractor had recommended a standard efficiency furnace, or the high efficiency furnace could not be installed due to size or location. The main drivers for the high efficiency furnaces were: lower natural gas costs; furnace features; the rebate program; and to have more efficient heating.

Advertising and promotion:
The most important sources of customer awareness for participants were: insert in Terasen Gas bill; heating contractor; radio advertisement and word of mouth. For, non-participants, the most important sources are: insert in Terasen Gas bill, heating contractor and mail advertisement.

For trade allies, the most important sources of awareness in decreasing order of importance are: BC contractor direct mail package, furnace manufacturers, radio advertisements, Terasen Gas regular contact, Terasen Gas trade newsletter, customers, and industry associations.

Program impact on high efficiency furnace sales and market:
Trade allies reported that the furnace market for new dwellings has grown by about 25% over the past 3 years while the replacement furnaces has grown by over 55% during the same time period. Over the same period, the penetration of high efficiency furnaces in new dwellings has increased from 19% to 37% and in the replacement market from 27% to 54%. These changes are consistent with a

rapid shift to a more efficient furnace market.

Impact of the Program on Prices:
Some concern has been raised that trade allies might try to capture part of the incentive by raising the prices of the high efficiency furnaces they sell. Price data was collected from participant and non-participants for high efficiency furnaces and was normalized with respect to capacity and to house area. There is no evidence from the data that trade allies were increasing the selling prices of their furnaces to capture part or all of the incentive paid to program participants for the year 2002.

Impact on Energy Savings and Peak Demand:
To estimate energy savings, unit savings were multiplied by the number of gross participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio to provide the estimate of net savings. Estimated net savings are 39.3TJ for each of the first 4.5 years and 18.4TJ for subsequent years. Estimated peak day savings is the weighted peak day heating load share for January multiplied by net savings and estimated peak day savings are 0.21TJ for the first 4.5 years and then 0.10TJ for subsequent years.

Impact on Carbon Dioxide Emissions:
Using an emissions factor of 50 tonnes of carbon dioxide per terajoule yields an emissions reduction or carbon dioxide savings of 1.97 kilotonnes of carbon dioxide for the first 4.5 years of the program and 0.92 kilotonnes of carbon dioxide for subsequent years of the program.

Impact on Market Transformation
The evidence examined in this study suggests that although the market for residential furnaces is not yet transformed, substantial progress in the direction of market transformation has been made. At a time of growing sales of new and replacement furnaces, high efficiency furnaces have increased their market share from about one-quarter of sales in the pre–program period to about one–half of sales in 2002.

1. Introduction

1.1 Program Overview

Energy conservation programs have two main rationales: environmental and economic. The environmental rationale is that reducing energy consumption can reduce harmful emissions implicated in global warming. Canada has joined most of the international community by signing the Kyoto Protocol in December 1997 and committed itself to reducing greenhouse gas emissions by six percent below the levels in 1990 between 2008 and 2012. The economic rationale is that reducing energy consumption and peak demand can reduce costs to both utilities and their customers if the marginal cost of energy conservation is less than the marginal cost of new supply. This applies particularly to programs that reduce peak demand and reduce the need for new transmission and distribution facilities that are needed for only a few days or hours per year.

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. This incentive was combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers. For the 2002 program, the furnace or boiler had to be purchased from August 1, 2002 to November 30, 2002. Participants received a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada. During this time period 2,785 people participated in the program, almost double the number who had participated in the 2001 program.

Program objectives for the Terasen Gas Heating System Upgrade Program included the following: realize residential energy savings; improve residential customer energy awareness; transform the residential furnace market; and assist residential customers in managing energy costs.

1.2 Outline of the Report

This report provides a process, market and impact evaluation of the Heating System Upgrade Program. Section 1 provides an overview of the Heating System Upgrade Program and of this study. Section 2 discusses the study objectives, approach, issues and methods used. Section 3 describes the key program elements including program design, program marketing and program delivery. Section 4 presents the results of the consumer survey while Section 5 presents the results of the trade ally survey. Section 6 summarizes the impact results including the effect of the program on furnace sales and market share, furnace prices, energy savings and carbon dioxide emissions. Section 7 provides the conclusions of the study.

2. Objectives and Approach

2.1 Study Objectives and Approach

Governments, regulators and utilities are increasingly looking to incentive programs to deliver cost effective energy savings and reduce greenhouse gas emissions. Evaluation of space heating and appliance incentive programs leads to analysis of three key objectives: first, to what extent does the incentive program result in incremental or additional purchases of the efficient measure; second, what impact does the incentive program have on prices for the technology paid in the market; third, how large are the energy savings that can validly be attributed to the program?

In typical program evaluations, considerable effort is placed on obtaining accurate estimates of gross technology savings, but less attention is given to market effects including price impacts of incentives, determinants of technology adoption, free rider analysis and costs. In this study we have provided Terasen Gas with a more useful and credible analysis by collecting valid information on market effects including prices and sales through detailed telephone surveys, and then combining this information with existing program data and engineering algorithms to undertake rigorous analysis of all evaluation issues.

The evaluation design includes a second phase of impact evaluation based on the analysis of billing consumption once the furnaces have been installed for a full heating season. It is anticipated that this work will be undertaken during the fall of 2004. At that time discrete choice analysis approaches will also be used to better understand the determinants of program participation and to revise the estimates of program participation.

2.2 Study Issues and Methods

Following the initial team meeting and review of the limited available research on efficient furnaces, eight critical issues emerged for this study:

- Examine the Efficient Furnace Program, with a view to assessing the rationale for the program.
- Examine the level of customer and trade ally awareness of the furnace technology and the program process.
- Examine the level of customer and trade ally satisfaction with both the furnace technology and the program process.
- Identify and examine program barriers and program opportunities.
- Assess the impact of advertising and promotion activity, including the NRCan funded additional advertising.
- Assess the impact of the program on sales and market share of high efficiency furnaces.
- Assess the impact of the program on prices of high efficiency furnaces.
- Assess the impact of program on energy savings and peak demand due to

reduced natural gas consumption.

- Assess the impact of the program on carbon dioxide emissions due to reduced natural gas consumption.

Given the wide scope of these issues, a number of data sources and methods were used in this study. An outline of the evaluation issues, data sources and methods is shown in Exhibit 2.1. Issue 1 was addressed primarily through the program interviews, the documents review and the literature review. Issues 2 to 6 were addressed primarily through the trade ally interviews and the customer and trade ally surveys. Issues 7 and 8 were addressed primarily through information from a conditional demand analysis.

Exhibit 2.1. Evaluation Issues, Data Sources and Methods

Issues	Data sources	Methods
1. Examine the Efficient Furnace Program, with a view to assessing the rationale for the program	Interviews Program documents Literature review	Program logic model
2. Examine level of customer and trade ally awareness of the furnace technology and the program process	Trade ally interviews Trade ally survey Customer survey	Cross tabulations
3. Examine level of customer and trade ally satisfaction with the furnace technology and the program process	Trade ally interviews Trade ally survey Customer survey	Cross tabulations
4. Identify and examine program barriers and program opportunities	Trade ally interviews Trade ally survey Customer survey	Cross tabulations
5. Assess the impact of advertising and promotion activity, including the NRCan additional advertising	Advertising plan Customer Survey	Cross tabulations
6. Assess the impact of the program on sales and market share of high efficiency furnaces	Trade ally survey Customer survey	Market share analysis Free rider analysis
7. Assess the impact of the program on prices of high efficiency furnaces	Trade ally survey Customer survey	Pricing analysis
8. Assess impact of program on energy savings and peak demand due to reduced natural gas consumption	Conditional demand study Weather data	Algorithms
9. Assess impact of program on carbon dioxide emissions due to reduced natural gas consumption	NR Can data	Algorithms

The customer survey collected included information on the following:

- Customer awareness (including timing) and sources of awareness of the program.
- Customer satisfaction with the program and its components.
- Customer demographic characteristics.
- Furnace characteristics including age, capacity and price.
- Housing characteristics including size and fuel types.
- Program barriers and opportunities.
- Program design issues.

The trade ally survey collected information on the following:

- Trade ally awareness and sources of awareness.
- Trade ally satisfaction with the program and its components.
- Trade ally firm characteristics.
- Characteristics of furnaces sold including efficiency level and price as well as market characteristics.
- Program barriers and opportunities.
- Program design issues.

It was determined that telephone surveys would be the best way to collect timely information while minimizing the response burden. The surveys were designed to provide as much comparability between survey groups as possible. This maximized the number of issues for which responses could be compared across the groups. The draft survey instrument was pre-tested and modified to improve several questions and to improve the flow of the instrument.

Because of the detailed nature of the research questions, particular care had to be used in the development of sample frames for the three groups: program participants or people who had received a rebate through the program; program non-participants or people who had purchased a new furnace outside the program during 1999 or 2002; and trade allies. The final sample consisted of 100 participants, 102 non-participants, and 20 trade allies.

The telephone surveys were conducted using a CATI system. Interviewers were fully briefed before the surveys were conducted to ensure that they understood the intent of the overall survey as well as each individual question. Up to five calls were made to each potential respondent to minimize response bias. Qualifying questions were asked to ensure that the appropriate individual completed the survey. As the responses were given, they were entered into an electronic database. Responses were then edited and cleaned.

Analysis of energy savings due to the program requires some care, because replacement of an existing furnace (with annual fuel utilization efficiency or AFUE on the order of perhaps 60%) with a new furnace (with minimum AFUE of 78% under the February 1995 regulations of the Energy Efficiency Act) will substantially reduce natural gas consumption, whether or not a high efficiency furnace is installed.

Direct annual energy savings are based on Equation (1).

(1) Energy savings = 82 GJ * (0.60/0.78 – 0.60/0.92)*(1 - FR)*(Gross participants)

where 82 GJ is the estimated base space heating load for program participants, 0.60 is the assumed AFUE for the old furnace or boiler, 0.92 is the typical AFUE for high efficiency natural gas furnaces, 0.78 is the minimum AFUE under the regulations of the Energy Efficiency Act, (1 – FR) is one minus the free rider rate estimated from residential customer survey data, and gross participants is the number of furnaces receiving rebates from program data in 2002. These savings pertain to the expected life of the furnace.

In addition to the direct annual energy savings noted above, it was determined as part of the surveys that the program induced people to replace furnaces earlier than they otherwise would have. This is classed as spill over savings and is based on Equation (2).

(2) Energy savings = 82 GJ * (0.60/0.60 – 0.60/0.78)*(Gross participants)*(Average years replaced early)

where 82 GJ is the estimated base space heating load for program participants, 0.60 is the assumed AFUE for the old furnace or boiler, 0.78 is the minimum AFUE under the regulations of the Energy Efficiency Act, gross participants is the attribution rate (or the share of furnaces replaced prematurely due to the program from customer survey data) times the number of furnaces rebated from program data in 2002. These savings pertain to the number of years the furnace would have been used before replacement.

Peak savings are based on Equation (3).

(3) Peak savings = (January's monthly share of annual heating degree days)*(1/31 days)*Energy savings.

3. Program Description

3.1 Program Design and Implementation

The original purposes of the Heating System Upgrade Program was to encourage home owners to consider energy efficiency when they were making furnace replacement decisions and ultimately to reduce peak natural gas demand, delay the need for incremental system investments, and reduce greenhouse gas emissions due to the residential sector. Research was undertaken to understand residential customer needs and the advantages and weaknesses of alternative program designs.

The Terasen Gas Heating System Upgrade Program offered financial incentives to customers purchasing and installing a new high efficiency gas furnace or boiler in their home. This incentive was combined with rebates and/or related offers from the leading residential furnace and boiler manufacturers. For the 2002 program, the furnace or boiler had to be purchased from August 1, 2002 to November 30, 2002. Participants received a $300 rebate on their natural gas bill, one-half paid by Terasen Gas and one-half paid by Natural Resources Canada. Details of these offers vary by manufacturer as shown below in Exhibit 3.2.

Program objectives for the Terasen Gas Heating System Upgrade Program included the following: realize residential energy savings; improve residential customer energy awareness; transform the residential furnace market; and assist residential customers in managing energy costs.

3.2 Program Marketing

The Heating System Upgrade Program has used a variety of mechanisms to ensure that potential clients are aware of the program. These mechanisms have included:

- Bill inserts.
- Advertising in Homewest and Westworld magazines.
- Direct mail.
- Terasen Gas web site advertising.
- Promotion at retail outlets.
- The manufacturers' dealer networks.
- Trades and contractors.
- Newspaper advertising.
- Radio advertising.
- Call center operators.

3.3 Delivery

In order to receive a rebate, the customer had a high efficiency furnace installed, completed a rebate coupon, attached a copy of the invoice, and forwarded the coupon and the invoice to CustomerWorks. If the required criteria were met, the invoice was processed, the customer's information entered into the program data base. If the relevant criteria were not met, a letter was sent to the customer informing them that the rebate was refused and explaining the reason why. If critical information was missing, a letter was sent to the customer with information on what was missing. Some 2785 households participated in the program in 2002.

3.4 Rationale

The rationale for the Heating System Upgrade Program is based on the premise that by providing customers with information on the advantages of high efficiency furnaces together with a financial incentive, customers will be encouraged to install high efficiency furnaces. This will result in significant energy conservation retrofits and measurable reductions in energy consumption and carbon dioxide emissions. Exhibit 3.1 outlines the rationale for the program and its activities. In summary, for each activity, the main linkages among inputs-outputs-outcomes and impacts are shown. There are strong and plausible linkages for each part of this chain confirming the logic of program design.

Exhibit 3.1. Program Logic Model

	Program design and implementation	Program marketing	Program delivery
Inputs	Assess customer needs and develop a program to meet these needs	Promotional activities including bill inserts, website, direct mail	Processing of applications and dispatch of letters to customers
Outputs	Program designed and implemented	Customer awareness of and interest in program increased	Provision of rebates to qualifying customers
Outcomes	Systems in place and operational	Increased customer intent to participate	Improved installation rate for high efficiency furnaces
Impacts	Reduced residential energy and peak consumption Reduced residential energy bills Reduced greenhouse gas emissions		

Exhibit 3.2. Manufacturers' Rebates

Manufacturer / Product	Terasen Gas and NRCan Rebate	Manufacturer Offer
Airco/Olsen – Furnace	$300	$100 rebate plus programmable thermostat total valued at $300
American Standard – Furnace	$300	10-year parts and labour warranty total valued at $490-$668
Armstrong – Furnace	$300	Programmable thermostat plus electrostatic filter total valued at $200
Bryant - Furnace/Boiler	$300	$150 rebate
Carrier – Furnace	$300	$150 rebate plus 10-year parts warranty total valued at $290
Heil – Furnace	$300	$150 rebate
Hydrotherm/Monitor – Boiler	$300	$1000 rebate
IBC Technologies Inc. – Boiler	$300	$200 rebate
Keeprite – Furnace	$300	$150 rebate
Kenmore – Furnace	$300	$150 rebate
Lennox – Furnace	$300	$250 rebate plus $750 in rebates on cooling/indoor air quality equipment total valued at $250-$1000
Lennox – Boiler	$300	5-year parts and labour extended warranty total valued at $175 to $400
Olsen – Boiler	$300	$100 plus programmable thermostat total valued at $300
Polaris - Hot Water Combo/Munchkin – Boiler	$300	$200 rebate
Quietstar – Boiler	$300	$150 rebate
Tempstar – Furnace	$300	$150 rebate
Trane – Furnace	$300	10-year parts and labour extended warranty total valued at $350-$560
Veissman – Furnace	$300	$150 rebate
York – Furnace	$300	10-year parts and labour extended warranty plus programmable thermostat total valued at $600

4. Customer Survey Results

4.1 Customer Awareness

Awareness of a program is the first step in the chain of actions that may eventually lead to program participation. Awareness of the Heating System Upgrade Program for participants and non-participants is shown in Exhibit 4.1. The share of respondents aware of the program is 91% for participants and 41% for non-participants.

Exhibit 4.1. Awareness of Heating System Upgrade Program

	Total (%)	Participants (%)	Non-participants (%)
Yes	65.8	91.0	41.2
No	33.2	9.0	56.9
DK/NR	1.0	-	2.0

Respondents were asked when they first became aware of the program as indicated in Exhibit 4.2. The pattern of initial awareness reflects the promotional activity and reflects the increased level of promotions in the fall of 2002 that was aimed at heightening awareness and increasing the level of participation. The initial fall campaign emphasized bill inserts, direct mail, inserts in Homeswest and Westworld, and radio. To enhance program awareness and increase program activity, additional promotion in the form of print advertising in daily / weekly papers and on radio was undertaken in October and early November.

Exhibit 4.2. Date of Initial Program Awareness

	Total (%)	Participants (%)	Non-participants (%)
1999	3.0	-	9.5
2000	6.8	1.1	19.0
2001	2.8	7.7	23.8
January 2002	-	-	-
February 2002	-	-	-
March 2002	3.0	3.3	2.4
April 2002	0.8	-	2.4
May 2002	0.8	1.0	-
June 2002	3.8	3.3	4.8
July 2002	9.0	12.1	2.4
August 2002	12.0	16.5	2.4
September 2002	18.8	26.4	2.4
October 2002	9.8	13.2	2.4
November 2002	3.0	4.4	1.5
December 2002	1.5	2.2	-
2002 month unknown	3.8	4.4	2.4
DK/NR	11.3	4.4	26.2

Understanding the importance of sources of program awareness is critical in evaluating the success of promotional strategies. The sources of overall awareness of the program, for those who indicated their awareness of the program in the previous question, are shown in Exhibit 4.3. For participants, the most important sources are: insert in Terasen Gas bill, heating contractor, radio advertisement and word of mouth. For, non-participants, the most important sources are insert in Terasen Gas bill, heating contractor and mail advertisement.

Exhibit 4.3. Source of Program Awareness

	Total (%)	Participants (%)	Non-participants (%)
Insert in Terasen Gas bill	59.4	64.8	47.6
Heating contractor	9.0	8.8	9.5
Radio advertisement	4.5	4.4	4.8
Mail advertisement	3.8	2.2	7.1
Word of mouth	.8	3.3	4.8
Furnace company/dealer	3.0	2.2	4.8
Insert in Province or Sun	2.3	2.2	2.4
In store advertisement	2.3	2.2	2.4
Insert in community newspaper	2.3	1.1	4.8
Home show	1.5	2.2	-
TV advertisement	1.5	2.2	-
Magazine advertisement	0.8	-	2.4
Shell Busey	0.8	1.1	-
Advertisement in TV Week	0.8	1.1	-
DK/NR	4.5	2.2	9.5

4.2 Customer Satisfaction

Customers were asked to indicate their level of satisfaction with program components on a five-point scale where one is not at all satisfied and five is very satisfied. Exhibit 4.4 shows the reported levels of satisfaction with the standard errors shown in parentheses. Participants reported satisfaction levels averaging 4.0 or more for information on the rebate procedure, time period for purchasing an eligible furnace and application procedures. Non-participants reported satisfaction levels of 4.0 or more information on the rebate program, application procedures and information about energy efficient furnaces.

Exhibit 4.4. Customer Satisfaction with Program Components (mean on 5-point scale)

	Total (%)	Participants (%)	Non-participants (%)
Information on the rebate program	4.38 (0.08)	4.38 (0.08)	4.40 (0.18)
Type of furnaces eligible for rebate	3.86 (0.11)	3.93 (0.12)	3.55 (0.27)
Time period for purchasing rebate eligible furnace	3.87 (0.11)	4.00 (0.12)	3.22 (0.32)
Application procedures	4.19 (0.10)	4.16 (0.11)	4.32 (0.17)
Amount of the rebate	3.95 (0.10)	3.99 (0.11)	3.79 (0.28)
Information about efficient furnaces	3.88 (0.10)	3.80 (0.11)	4.19 (0.19)

Note: Standard error in parentheses.

Customers were asked to indicate their level of satisfaction with the various aspects of their furnace on a five-point scale where one is not at all satisfied and five is very satisfied. Exhibit 4.5 shows the reported levels of satisfaction with the standard errors shown in parentheses. Participants reported satisfaction levels averaging 4.0 or more for reliability of the furnace, gas consumption, ease of installation of furnace, after sales service and size of natural gas bill. Non-participants reported satisfaction levels of 4.0 or more for price of furnace, reliability of furnace, gas consumption, ease of installation and after sales service.

Exhibit 4.5. Customer Satisfaction with Their Furnace (mean on 5-point scale)

	Total (%)	Participants (%)	Non-participants (%)
Price of furnace	4.07 (0.07)	3.96 (0.09)	4.18 (0.10)
Reliability of furnace	4.64 (0.04)	4.66 (0.06)	4.63 (0.06)
Gas consumption	4.24 (0.06)	4.44 (0.07)	4.04 (0.09)
Ease of installation of furnace	4.21 (0.07)	4.06 (0.11)	4.36 (0.09)
After sales service	4.15 (0.09)	4.04 (0.13)	4.26 (0.11)
Size of natural gas bill	3.95 (0.08)	4.19 (0.11)	3.70 (0.12)

Note: Standard error in parentheses.

Respondents were asked if they had any problems with their new furnace. As Exhibit 4.6 shows, the share of respondents reporting problems was about 12% for participants and about 8% for non-participants. Among those with problems with their furnace, the most common problems were: the furnace had required major repairs; the furnace was too noisy; and furnace had excessive vibration.

Exhibit 4.6. Had any Problems with Furnace

	Total (%)	Participants (%)	Non-participants (%)
Yes	9.9	12.0	7.8
No	90.1	88.0	92.2
DK/NR	-	-	-

4.3 Customer Characteristics

Information was collected on a variety of respondent characteristics. Exhibit 4.7 shows the age distribution of respondents. For participants, the largest group was in the age range 46-54 years and the second largest group was in the age range 55-64 years. For non-participants the largest group was in the age range 45-54 years and the second largest group was in the 65 years and over age range.

Exhibit 4.7. Age of Respondents

	Total (%)	Participants (%)	Non-participants (%)
25-34 years	5.4	7.0	3.9
35-44 years	8.9	10.0	7.8
45-54 years	38.1	40.0	36.3
55-64 years	24.8	27.0	22.5
65 years +	21.3	15.0	27.5
DK/NR	1.5	1.0	2.0

Marital status of respondents is shown in Exhibit 4.8. The participant sample has 7% singles, 88% married or common law; none divorced or separated; and 3% widowed. The non-participant sample has 7% single; 75% married or common law; 6% divorced or separated; and 2% widowed.

Exhibit 4.8. Marital Status

	Total (%)	Participants (%)	Non-participants (%)
Singles	6.9	7.0	6.9
Married/common law	81.2	88.0	74.5
Divorced/separated	3.0	-	5.9
Widowed	6.9	3.0	10.8
DK/NR	2.0	2.0	2.0

Highest level of education attained by respondents is shown in Exhibit 4.9. The participant sample has larger share of respondents who have completed university or college or completed trade or technical school than the non-participant sample.

Exhibit 4.9. Highest Level of Education Attained

	Total (%)	Participants (%)	Non-participants (%)
Some high school	8.4	9.0	7.8
Completed high school	21.8	18.0	25.5
Some university/college	16.3	13.0	19.6
Completed university/college	31.2	37.0	25.5
Some trade/technical school	3.0	3.0	2.9
Completed trade/technical school	4.0	5.0	2.9
Post graduate	8.4	10.0	6.9
DK/NR	6.9	5.0	8.8

Number of people in the house is shown in Exhibit 4.10 with standard errors in parentheses. The total sample has an average of 2.6 people per house, the participant sample an average of 2.8 people per house and the non-participant sample an average of 2.5 people per house.

Exhibit 4.10. Number of People in House

	Total	Participants	Non-participants
Average	2.64 (0.08)	2.78 (0.11)	2.50 (0.11)

Note: Standard error in parentheses.

4.4 Furnace Characteristics

Respondents were asked a range of questions about the replaced furnaces. The average age of furnaces at time of replacement was about 24.3 years overall, about 24.7 years for participants and about 23.9 years for non-participants. The average number of years respondents thought a furnace should last before replacement was about 25.2 years overall, about 24.9 years for participants and about 25.6 years for non-participants. The share of furnaces working at time of replacement was about 90% overall, about 94% for participants and about 85% for non-participants.

Exhibit 4.11. Characteristics of the Replaced Furnace

	Total	Participants	Non-participants
Age of the furnace at time of replacement (years)	24.34 (0.72)	24.72 (0.72)	23.92 (1.30)
How many years should a furnace last before replacement (years)	25.20 (1.00)	24.85 (1.46)	25.55 (1.37)
Was furnace working at time of replacement (respondent share stating furnace was working)	89.6%	94.0%	85.3%

Note: Standard error in parentheses.

Respondents were asked the reasons for furnace replacement, where multiple responses were recorded. For participants the main reasons for furnace replacement included: wanted more efficient furnace; anticipated furnace failure; wanted lower cost alternative; existence of the rebate; furnace had failed; age of furnace; and furnace required too many repairs. For non-participants the main reasons for furnace replacement included: wanted more efficient furnace; anticipated furnace failure; furnace had failed; and furnace required too many repairs.

Exhibit 4.12. Reasons for Furnace Replacement (share of respondents with multiple responses allowed)

	Total (%)	Participants (%)	Non-participants (%)
Wanted more efficient furnace	64.4	73.0	55.9
Anticipated furnace failure	15.3	16.0	14.7
Wanted lower cost alternative	9.9	17.0	2.9
Furnace had failed	7.9	5.0	10.8
Furnace required too many repairs	7.9	4.0	11.8
Existence of the rebate	4.0	8.0	-
Age of furnace	4.0	5.0	2.9
Safety reasons	3.0	3.0	2.9
Wanted to change to natural gas	2.5	1.0	3.9
New home	1.5	-	2.9
Wanted an environmentally friendly fuel	1.5	2.0	1.0
Furnace was too big	1.5	2.0	1.0
Heated floor area increased	1.0	-	2.0
House was too cold	0.5	1.0	-
Miscellaneous	3.5	2.0	4.9
DK/NR	0.5	-	1.0

The efficiency level of the new furnace is shown in Exhibit 4.13. All furnaces purchased by participants were of course high efficiency, while 54% of furnaces purchased by non-participants were noted as high efficiency. However, there is some uncertainty in the reported incidence of high efficiency furnaces by non-participants due to their not understanding the actual efficiency of the installed furnace.

Exhibit 4.13. Efficiency Level of New Furnace

	Total (%)	Participants (%)	Non-participants (%)
Standard efficiency	18.8	-	37.3
High efficiency	76.7	100.0	53.9
DK/NR	4.5	-	8.8

The efficiency level of the previous furnace is shown in Exhibit 4.14. Overall about 85% of respondents had a standard efficiency furnace while 91% of participants and 77% of non-participants had a standard efficiency furnace.

Exhibit 4.14. Efficiency Level of Previous Furnace

	Total (%)	Participants (%)	Non-participants (%)
Standard efficiency	84.5	91.0	77.4
High efficiency	7.8	7.0	8.6
DK/NR	7.8	2.0	14.0

The capacity of the new furnace is shown in Btus per hour in Exhibit 4.15. The average capacity for the whole sample is about 85,000 Btuh, for participants is about 74,000 Btuh and for non-participants is about 100,000 Btuh.

Exhibit 4.15. Capacity of New Furnace (Btu per hour)

	Total (%)	Participants (%)	Non-participants (%)
Average	84,929 (9,167)	73,896 (4,898)	100,048 (20,450)

Note: Standard error in parentheses.

Respondents were asked about the behavior of their previous furnace fan as indicated in Exhibit 4.16. Before the furnace change, about 19% of all fans ran continuously with this share at 20% for participants and 19% for non-participants.

Exhibit 4.16. Furnace Fan Behavior Before Furnace Change

	Total (%)	Participants (%)	Non-participants (%)
Ran intermittently	74.3	79.0	69.6
Ran continuously	19.3	20.0	18.6
DK/NR	6.4	1.0	11.8

Respondents were asked about the behavior of their current furnace fan as indicated in Exhibit 4.17. After the furnace change, about 15% of all fans ran continuously with this share at 20% for participants and 10% for non-participants.

Exhibit 4.17. Furnace Fan Behavior After Furnace Change

	Total (%)	Participants (%)	Non-participants (%)
Runs intermittently	80.7	76.0	85.3
Runs continuously	14.9	20.0	9.8
DK/NR	4.5	4.0	4.9

4.5 Housing Characteristics

Dwelling type for respondents are shown in Exhibit 4.8. Single detached homes dominated the sample, with the share of single detached dwellings at 93% for the whole sample, 96% for participants and 90 % for non-participants.

Exhibit 4.18. Dwelling Type

	Total (%)	Participants (%)	Non-participants (%)
Single detached	93.1	96.0	90.2
Row/townhouse	3.0	-	5.9
Mobile/other	2.5	3.0	2.0
Apartment/condominium	0.5	-	1.0
DK/NR	1.0	1.0	1.0

The average age of the house is shown in Exhibit 4.19. The average age of dwelling was 31.0 years overall, 32.8 years for participants, and 29.1 years for non-participants.

Exhibit 4.19. Age of Home

	Total	Participants	Non-participants
Years	31.0 (1.14)	32.8 (1.78)	29.1 (1.42)

Note: Standard error in parentheses.

Natural gas uses in the dwelling are shown in Exhibit 4.20. Main uses are space heating, water heating, fireplaces, cooking and barbequing. Less important uses are clothes drying, hot tubs and pool heating.

Exhibit 4.20. Natural Gas Uses in the Home

	Total (%)	Participants (%)	Non-participants (%)
Space heating	100.0	100.0	100.0
Water heating	91.6	94.0	89.2
Fireplace insert	45.0	49.0	41.2
Cooking	19.8	20.0	27.5
Barbeque	16.8	14.0	19.6
Clothes drying	9.4	11.0	7.8
Hot tub	5.0	5.0	4.9
Outdoor pool heating	2.5	3.0	2.0
Indoor pool heating	1.0	-	2.0
NR	3.0	3.0	2.9

4.6 Barriers and Opportunities

Customers who purchased a standard efficiency furnace were asked why they chose a standard efficiency furnace instead of a high efficiency furnace. The most important reasons were: high efficiency furnace was too expensive, contractor recommended standard efficiency, and could not install because of size or location.

Exhibit 4.21. Why Standard Efficiency Furnace was Chosen

	Total (%)	Participants (%)	Non-participants (%)
High efficiency furnace was too expensive	57.9	-	57.9
Contractor recommended standard efficiency	13.2	-	13.2
Could not install because of size or location	7.9	-	7.9
High efficiency lacked desired features	2.6	-	2.6
Unfamiliar with high efficiency furnace	2.6	-	2.6
Influenced by the Furnace Tune Up Program	2.6	-	2.6
Miscellaneous	13.2	-	13.2
DK/NR	5.2	-	5.2

Customers who purchased a high efficiency furnace were asked why they chose a high efficiency furnace instead of a standard efficiency furnace. The most important reasons were high efficiency furnace had lower gas costs, high efficiency furnace was more reliable, high efficiency furnace had desired features, availability of the rebate program and to have better/more efficient heating

Exhibit 4.22. Why High Efficiency Furnace was Chosen (share of response)

	Total (%)	Participants (%)	Non-participants (%)
High efficiency furnace had lower gas costs	73.5	79.0	63.6
High efficiency furnace was more reliable	9.0	4.0	18.2
High efficiency furnace had desired features	8.4	6.0	12.7
Rebate program	6.5	10.0	-
Better/more efficient heating	6.5	7.0	5.5
Contractor recommended high efficiency furnace	4.5	4.0	5.5
Environmental reasons	3.2	5.0	-
Influenced by the Furnace Tune Up Program	0.6	1.0	-
Recommendation from Shell Busey's Show	0.6	1.0	-
Improves house resale value	0.6	1.0	-
Miscellaneous	4.5	5.0	3.6
DK/NR	1.3	-	3.6

All respondents were asked about the factors affecting the purchase of a new furnace. Exhibit 4.23 indicated the importance of variety of factors on this decision where one is not at all important and five is very important. For the overall sample, the reasons ranked an average of 4.0 or greater were furnace reliability, amount of gas consumed, furnace heating capacity, furnace energy efficiency, impact on environment, after sales service, safety of furnace, warranty offered and natural gas price volatility.

Exhibit 4.23. Factors Affecting Choice of a New Furnace

	Total (%)	Participants (%)	Non-participants (%)
Furnace price	3.94 (0.07)	3.82 (0.10)	4.05 (0.11)
Furnace features	3.90 (0.07)	4.06 (0.10)	3.73 (0.11)
Furnace reliability	4.76 (0.04)	4.67 (0.06)	4.84 (0.04)
Availability of rebate	3.26 (0.10)	3.59 (0.12)	2.92 (0.15)
Amount of gas consumed	4.64 (0.05)	4.74 (0.05)	4.55 (0.09)
Brand name	3.22 (0.09)	3.46 (0.13)	2.97 (0.13)
Furnace heating capacity	4.37 (0.06)	4.31 (0.09)	4.43 (0.08)
Furnace energy efficiency	4.70 (0.04)	4.79 (0.04)	4.61 (0.06)
Impact on environment	4.09 (0.08)	4.24 (0.10)	3.9 (0.12)
After sales service	4.24 (0.07)	4.32 (0.09)	4.17 (0.11)
Safety of furnace	4.72 (0.05)	4.58 (0.09)	4.85 (0.05)
Warranty offered	4.38 (0.06)	4.1 (0.09)	4.35 (0.08)
Natural gas price volatility	4.18 (0.08)	4.21 (0.09)	4.15 (0.12)

Note: Standard error in parentheses.

4.7 Program Design

A number of issues were explored to help with the design of a possible future program. Respondents were asked if they had enough information to make an informed decision on furnace choice. About 96% of participants and about 83% of non-participants indicated that they did have enough information. Those who needed more information cited the following areas where information was missing: more information in general; could not understand technical information; and poor contractor knowledge;

Exhibit 4.24. Customers Had Enough Information to Make Informed Decision on Furnace Choice

	Total (%)	Participants (%)	Non-participants (%)
Yes	89.6	96.0	83.3
No	8.9	3.0	1.7
DK/NR	1.5	1.0	2.0

Respondents were asked if they were familiar with the Energy Star label for furnaces. About 43% of the overall sample, 47% of participants and 38% of non-participants were familiar with the Energy Star label for furnaces.

Exhibit 4.25. Familiar with the Energy Star Label for Furnaces

	Total (%)	Participants (%)	Non-participants (%)
Yes	42.6	47.0	38.2
No	52.0	52.0	52.0
DK/NR	5.4	1.0	9.8

Respondents were asked if they found an Energy Star label on the furnace they bought. About 65% of the overall sample, 70% of participants and 59% of non-participants found the Energy Star label for furnaces on the furnace they bought.

Exhibit 4.26. Found an Energy Star Label for Furnace that was Purchased

	Total (%)	Participants (%)	Non-participants (%)
Yes	65.1	70.2	59.0
No	15.1	6.4	25.6
DK/NR	19.8	23.4	15.4

For the overall sample, the best months to offer an energy efficient furnace program were September, October, August and November as shown in Exhibit 4.27.

Exhibit 4.27. Best Month to Offer an Energy Efficient Furnace Program

	Total (%)	Participants (%)	Non-participants (%)
September	53.5	58.0	49.0
October	35.6	41.0	30.4
August	27.2	32.0	22.5
November	21.3	26.0	16.7
July	16.8	19.0	14.7
December	15.8	18.0	13.7
June	15.3	18.0	12.7
January	11.9	10.0	13.7
March	10.9	11.0	10.8
February	10.4	10.0	10.8
May	9.4	8.0	10.8
April	6.9	5.0	8.8
DK/NR	5.0	5.0	4.9

4.8 Furnace Prices

Respondents were asked the installed price of their new furnace, including any applicable taxes. Exhibit 4.28 shows the mean price paid for participants, non-participants who purchased standard efficiency furnaces and non-participants who purchased high efficiency furnaces. The average prices paid were $3239 overall, $3142 for participants, $2337 for non-participants buying standard efficiency furnaces and $3648 for non-participants buying high efficiency furnaces. While this data indicates that participants paid about $ 507 less than non-participants, there are differences in house and furnace sizes that complicate the comparison, and are considered in Section 6. Further detail on the distribution of furnaces by price is given in Exhibit 4.29.

Exhibit 4.28. Furnace Prices (dollars)

	Total (all)	Participants (high efficiency)	Non-participants (standard efficiency)	Non-participants (high efficiency)
Mean	3239.20	3141.60	2336.60	3648.40
Standard error	219.29	144.07	156.85	746.78

Exhibit 4.29. Distribution of Furnaces by Price (percentage)

	Total (all)	Participants (high efficiency)	Non-participants (standard efficiency)	Non-participants (high efficiency)
$1000 or less	2.0	-	2.6	5.5
$1001-$2000	17.8	12.0	36.8	14.5
$2001-$3000	27.2	23.0	28.9	32.7
$3001-$4000	23.3	34.0	10.5	16.4
$4001-$5000	6.9	11.0	2.6	3.6
$5001-$6000	2.5	4.0	-	1.8
$6001-$7000	1.5	-	-	5.5
Over $7000	1.0	1.0	-	1.8
DK/NR	17.8	15.0	18.4	18.2

4.9 Free Rider and Spill Over Analysis

Program participants were asked how important the Heating System Upgrade Program was in their decision to install a high efficiency furnace, where one was not at all important and five was very important as shown in Exhibit 4.30. To summarize the impact of the program, a weighted average of the importance scores was calculated, where the weights were as follows: score of five has weight of 1.00, score of four has weight of 0.75, score of three has weight of 0.50, score of two has weight of 0.25 and score of one has weight of 0.00. The weighted average of the importance scores is one minus the free rider rate, and indicates a free rider rate of about 40%.

Exhibit 4.30. Free Rider Analysis

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.247	0.280	0.237	0.075	0.151	
Product	0.247	0.210	0.119	0.019	0.000	0.595

Program participants were asked if they replaced the furnace early because of the availability of the rebate. As Exhibit 4.31 indicates 39.8% of participants indicated that they had replaced the furnaces early by an average of 1.97 years because of the availability of the rebate. Weighted across all respondents, furnaces were replaced an average of 0.772 years early because of the availability of the rebate.

Exhibit 4.31. Spill Over Analysis

	Replaced early (%)	Years replaced early	Weighted average years replaced early
Yes	39.8	1.97	0.784
No	60.2	0.00	0.000
DK/NR	-	-	-
Total participants	-	-	0.784

5. Trade Ally Survey Results

5.1 Trade Ally Awareness

Trade ally awareness of a program is critical for the supply side of the market. Awareness of the Heating System Upgrade Program for trade allies is shown in Exhibit 4.1. All trade allies surveyed were aware of the Heating System Upgrade Program.

Exhibit 5.1. Awareness of Heating System Upgrade

	Share (%)
Yes	100.0
No	-

Trade allies were asked the source of their awareness of the program where multiple responses were allowed. The most important sources of awareness in decreasing order of importance were BC contractor direct mail package, furnace manufacturers, radio advertisements, Terasen Gas regular contact, Terasen Gas trade newsletter, customers, and industry associations.

Exhibit 5.2. Source of Program Awareness

	Share (%)
Terasen Gas contractor direct mail package	85.0
Furnace manufacturers	25.0
Radio advertisements	25.0
Terasen Gas regular contact	20.0
Terasen Gas trade newsletter	15.0
Customers	15.0
Industry associations	15.0
Local newspaper insert	10.0
Terasen Gas bill insert	10.0
Shell Busey	10.0
Word of mouth	10.0
Mall advertisement	5.0
Terasen Gas website	5.0

5.2 Trade Ally Satisfaction

Trade allies were asked to indicate their level of satisfaction with program components on a five-point scale where one is not at all satisfied and five is very satisfied. Exhibit 5.3 shows the reported levels of satisfaction with the standard errors shown in parentheses. Trade allies reported satisfaction levels averaging 4.0 or more for information on the rebate procedure, application procedures to obtain the rebate, amount of the rebate and promotional activities of Shell Busey.

Exhibit 5.3. Trade Ally Satisfaction with Program (mean on 5-point scale)

	Component
Information on the rebate	4.25 (0.24)
Types of furnaces eligible for a rebate	3.90 (0.32)
Time period for purchasing an eligible furnace	3.50 (0.28)
Application procedures to obtain the rebate	4.40 (0.24)
Amount of the rebate	4.25 (0.24)
Promotional activities of Shell Busey	4.05 (0.37)

Note: Standard error in parentheses.

5.3 Trade Ally Characteristics

The average number of employees in reporting firms was 8.1 with a standard error of 1.56. Above one-half of firms have five employees or less.

Exhibit 5.4. Number of Employees

	Share (%)
Mean	8.10 (1.56)
Up to 2	20.0
3 to 5	30.0
6 to 10	20.0
Over 10	30.0

Note: Standard error in parentheses.

The main type of business is shown in Exhibit 5.5. The primary business shares are 55% for furnace retrofits, 25% for new installations, 10% for service and 10% for plumbing.

Exhibit 5.5. Primary Business

	Share (%)
Furnace retrofits	55.0
New installations	25.0
Service	10.0
Plumbing	10.0

The main specializations of firms are shown in Exhibit 5.6. Most firms specialize in forced air heating.

Exhibit 5.6. Specialization

	Share (%)
Residential forced air heating	90.0
Residential hydronic heating	50.0

5.4 Furnace Characteristics

Trade allies were asked a range of questions about the replaced furnaces. Trade allies indicated that on average about 76% of furnaces were operating and producing heat at the time of replacement as shown in Exhibit 5.7.

Exhibit 5.7. Share of Furnaces
Operational at Time of Replacement

	Share (%)
Mean	76.2 (5.28)
Up to 74%	30.0
75% to 84%	20.0
85% to 94%	35.0
95% to 100%	15.0
DK/NR	-

Note: Standard error in parentheses.

Trade allies were asked to estimate the remaining life of furnaces at the time of replacement. The average remaining furnace life at replacement was about 4.5 years as shown in Exhibit 5.8.

Exhibit 5.8. Average Remaining Furnace Life at Replacement

	Share (%)
Mean (years)	4.48 (1.13)
Less than 1 year	15.0
1 to 5 years	40.0
6 to 10 years	20.0
Over 10 years	10.0
DK/NR	15.0

Trade allies were asked if they routinely do a heat calculation. As Exhibit 5.9 indicates, about 65% of trade allies routinely do a heat calculation while about 35% of trade allies do not routinely do a heat loss calculation.

Exhibit 5.9. Routinely do Heat Loss Calculation

	Share (%)
Yes	65%
No	35%

Those trade allies who routinely do a heat loss calculation were asked what share of the time the heat loss calculation leads to a smaller capacity furnace. About 41% of the time, heat calculations leads to installation of a smaller capacity furnace.

Exhibit 5.10. Share of Time Heat Loss Calculation Leads to Smaller Capacity Furnace

	Share (%)
Mean	41.0 (13.6)
Up to 25%	38.5
26% to 50%	7.7
51% to 75%	7.7
76% to 100%	23.1
DK/NR	23.12

Note: Standard error in parentheses.

Respondents were asked to indicate the importance of various factors affecting their customers' choice of furnace, where one is not at all important and five is very important, with standard errors in parentheses. Those factors with an average value of 4.0 or above include furnace prices, furnace features, furnace reliability, availability of rebate, amount of gas consumed, brand name, furnace efficiency, after sales service, safety of furnace, warranty offered and volatility of gas prices.

Exhibit 5.11. Trade Ally Views of Importance of Factors Affecting Choice of Furnace

	Share (%)
Furnace prices	4.45 (0.18)
Furnace features	4.00 (0.21)
Furnace reliability	4.80 (0.09)
Availability of rebate	4.10 (0.20)
Amount of gas consumed	4.55 (0.14)
Brand name	4.00 (0.22)
Furnace heating capacity	3.50 (0.26)
Furnace efficiency	4.45 (0.15)
Impact on environment	3.00 (0.32)
After sales service	4.30 (0.18)
Safety of furnace	4.50 (0.17)
Warranty offered	4.40 (0.17)
Volatility of gas prices	4.15 (0.28)
Energy Star label	3.45 (0.31)

Note: Standard error in parentheses.

A number of questions were asked to determine factors affecting trade ally recommendations to customers on choice of furnace. Exhibit 5.12 shows that almost one-quarter of locations are viewed as unsuitable for high efficiency replacement furnaces.

Exhibit 5.12. Share of Customers for Which High Efficiency Furnace Not Economic due to Furnace Location

	Share (%)
Mean	24.1 (4.60)
Up to 10%	40.0
11% to 40%	35.0
Over 40%	20.0
DK/NR	5.0

Note: Standard error in parentheses.

About three-quarters of trade allies believe that high efficiency furnaces are the best choice for their customers while another 10% believe that high efficiency furnaces are sometimes the best choice for their customers.

Exhibit 5.13. Believe that High Efficiency Furnaces Best Choice for Customers

	Share (%)
Yes	75.0
No	25.0
Sometimes/depends on customer	10.0

Given the previous results, it is not surprising that 70% of trade allies recommend high efficiency furnaces to their residential customers as indicated in Exhibit 5.14.

Exhibit 5.14. Recommend High Efficiency Furnaces to Customers

	Share (%)
Yes	70.0
No	5.0
Sometimes/depends on customer	25.0

Sometimes a two-stage furnace mid efficiency furnace is recommended as the preferred option as shown in the next Exhibit 5.15.

Exhibit 5.15. Recommend Two-stage Mid efficiency
Furnaces as Preferred Option

	Share (%)
Yes	40.0
No	50.0
Sometimes/depends on customer	10.0

Trade allies were asked to compare the comfort received by their customers from mid efficiency and high efficiency furnaces. Some 40% of respondents indicated that high efficiency furnaces provided more comfort and 50% of respondents indicated that high efficiency furnaces provided the same comfort.

Exhibit 5.16. High Efficiency Furnaces Provide More,
Same or Less Comfort than Mid Efficiency

	Share (%)
More comfort	40.0
Same comfort	50.0
Less comfort	-
DK/NR	10.0

Continuously running ventilation fans can increase use of electrical energy. The shares of installations where furnace fans run continuously are shown in Exhibit 5.17.

Exhibit 5.17. Share of Installations Where
Ventilation Fan Runs Continuously

	Standard efficiency (%)	Mid efficiency (%)	High efficiency (%)
Mean*	19.8 (7.07)	24.5 (7.50)	32.4 (9.11)
0%	30.0	35.0	30.0
1% to 20%	30.0	20.0	20.0
21% to 50%	5.0	15.0	5.0
51% to 75%	10.0	5.0	15.0
76% to 100%	5.0	10.0	15.0
DK/NR	20.0	15.0	15.0

* % of installations where fan runs continuously
Note: Standard error in parentheses.

5.5 Market Characteristics

Trade allies were asked a number of questions pertaining to the market for furnaces. Trade allies estimated that about three-quarters of the market involves replacement furnaces. However, it should be noted that the trade allies covered in this research were those who participated in the Terasen program, and survey results pertaining to the new furnace market may not be representative of the new construction market.

Exhibit 5.18. Share of Sales Involving Replacement Furnaces

	Shares
Mean share	75.6 (6.92)
Up to 25%	15.0
26% to 50%	15.0
51% to 75%	-
76% and more	70.0

Note: Standard error in parentheses.

Trade allies were also asked to provide information on the composition of their furnace sales by type. Average respondent share of sales for high efficiency furnaces for new dwellings increased from 19% in 2000 to 25% in 2001 and to 37% in 2002. Average respondent share of sales for high efficiency furnaces for replacement furnaces increased from 27% in 2000 to 37% in 2001 and to 54% in 2002. This is consistent with a rapid shift towards a more efficient furnace market. The shares of sales involving high efficiency furnaces are shown in Exhibit 5.19.

Exhibit 5.19. Share of Sales Involving
High Efficiency Furnaces

	Share new dwellings (%)	Share replace-ments (%)	Weight new dwellings	Weight replace-ments	Weighted share new dwellings	Weighted share replace-ments	Overall
2000	18.8	26.5	0.244	0.756	4.6	20.0	24.6
2001	24.6	37.2	0.244	0.756	6.0	28.1	34.1
2002	37.4	54.1	0.244	0.756	9.1	40.9	50.0

Exhibit 5.19 also provides an estimate of the share of condensing furnaces in the overall furnace market. The share of high efficiency or condensing furnaces increased from some 25% in 2000, to 34% in 2001 and 50% in 2002. For the five years 1996 to 2000, the share of condensing furnaces in Canada had stabilised at about 40 %. We believe that the share of condensing furnaces in the BC market also stabilised but at about 25% for this period. This is a significantly lower level than the national one, but it is a level consistent with the

relatively low number of heating degree days in the Lower Mainland and Vancouver Island compared to much of the rest of Canada. A lower number of heating degree reduces the economic benefits of a condensing furnace.

Trade allies were asked to provide information on their sales of furnaces. Average respondent sales for new dwellings increased from 31.4 units in 2000 to 36.7 units in 2001 and to 39.6 units in 2002. Average respondent sales for replacement furnaces increased from 39.9 units in 2000 to 48.4 units in 2001 and to 62.1 units in 2002. Assuming that our sample is representative of the broader market, this suggests quite strong growth in the furnace market.

Exhibit 5.20. Average Furnace Sales

	New dwellings (units)	Replacements (units)	Total (units)	Growth rate (%)
2000	31.4	39.9	71.3	-
2001	36.7	48.4	85.1	19.4
2002	39.6	62.1	101.7	19.5

Trade allies were asked to report on their share of their customer who took advantage of the Heating System Upgrade program with the results as shown in Exhibit 5.21.

Exhibit 5.21. Share of Customers Who Took Advantage of the Rebate Program

	Share (%)
Mean	76.7 (6.98)
Up to 50%	26.7
51% to 80%	13.3
81% to 90%	26.7
81% to 90%	33.3

The level of trade ally involvement is a critical driver of program success. About one-half of respondents advertised the program to their customers. About 90% of respondents agreed that the program increased their business with an increase of business of some 23% for those respondents.

Exhibit 5.22. Program Involvement

	Advertised program to customers (%)	Increase in business resulted for program (%)	Percentage increase in business if yes (%)
Yes	50.0	90.0	23.4
No	50.0	10.0	NA

5.6 Barriers and Opportunities

A number of questions explored trade ally perceptions of program barriers and opportunities. About 80% of trade allies felt that customers had enough information to make an informed decision on furnace choice.

Exhibit 5.23. Customers Have Enough Information to Make Informed Decision on Furnace Choice

	Share (%)
Yes	80.0
No	15.0
DK/NR	5.0

Trade ally views of customer satisfaction were explored for price reliability, and natural gas consumption. Their views were that their customers rated mid efficiency furnaces more highly with respect to price but rated high efficiency furnaces more highly with respect to natural gas consumption. Reliability was rated as about equal between the two types of furnaces.

Exhibit 5.24. Trade Ally Views of Customer Satisfaction (mean on a 5-point scale)

	Mid efficiency furnaces	High efficiency furnaces
Price	4.25 (0.19)	3.70 (0.23)
Reliability	4.35 (0.20)	4.45 (0.20)
Gas consumption	3.55 (0.26)	4.50 (0.18)

Note: Standard error in parentheses.

5.7 Program Design

Several issues of relevance to design of a future program were explored in the survey. Peak months for furnace sales in descending order of importance were October, September, November, December, August and January.

Exhibit 5.25. Peak Months for Furnace Sales

	Share of respondents Choosing this month
October	90.0
September	80.0
November	65.0
December	35.0
August	10.0
January	5.0
DK/NR	5.0

The best months to offer a furnace program were September, October, August, November, December, May, June, July, April, January, March and February.

Exhibit 5.26. Best Months to Offer Furnace Program

	Share (%)
September	80.0
October	70.0
August	50.0
November	45.0
December	40.0
May	30.0
June	30.0
July	30.0
April	30.0
January	25.0
March	20.0
February	20.0

The average share of sales made during the respondents preferred months was about 67% as shown in Exhibit 5.27.

Exhibit 5.27. Share of Sales Made During These Months

	Share (%)
Mean	67.4 (5.37)
Up to 74%	55.0
75% to 84%	15.0
85% to 94%	10.0
95% to 100%	15.0
DK/NR	5.0

Note: Standard error in parentheses.

Some 70% of trade allies were familiar with Energy Star furnaces as indicated in Exhibit 5.28.

Exhibit 5.28. Familiar with Energy Star for Furnaces

	Share (%)
Yes	70.0
No	30.0

In response to a request for suggestions on how customers could be encouraged to install high efficiency furnaces, the suggestions were: making customers more aware of costs and savings (30%), lowering the price of high efficiency furnaces (15%), providing a higher rebate (15%), providing more information (5%) and provide a chart showing the cost recovery period (5%).

Exhibit 5.29. Suggestions on How Customers Could be Encouraged to Install High Efficiency

	Share (%)
More aware of cost/savings	30.0
Lower the price	15.0
Higher rebate	15.0
More information	5.0
Chart show cost recovery period	5.0
DK/NR	25.0

5.8 Furnace Prices

Trade allies were asked to estimate typical equipment and installed prices for a 90,000 Btuh mid efficiency furnace, a 90,000 Bthu high efficiency furnace and a 75,000 Btuh high efficiency furnace which provides approximately the same heating capability as the 90,000 Btuh mid efficiency furnace. The results are shown in Exhibit 5.30.

Exhibit 5.30. Equipment Price and Installed Price for
90 MBtuh mid efficiency and 75 MBtuh high efficiency Furnace

	90,000 Btuh		75,000 Btuh
	Mid efficiency (dollars)	High efficiency (dollars)	High efficiency (dollars)
Equipment price	1067.60 (51.97)	1595.90 (104.69)	1504.20 (116.20)
Installed price	2194.20 (80.94)	3120.80 (114.95)	3071.30 (128.88)

Note: Standard error in parentheses.

5.9 Free Riders and Spill Over Analysis

Trade allies were asked how important the Heating System Upgrade Program was in the customers' decisions to install a high efficiency furnace, where one was not at all important and five was very important as shown in Exhibit 5.31. To summarize the impact of the program, a weighted average of the importance scores was calculated, where the weights were as follows: score of five has weight of 1.00, score of four has weight of 0.75, score of three has weight of 0.50, score of two has weight of 0.25 and score of one has weight of 0.00. The weighted average of the importance scores is one minus the free rider rate of about 0.69.

Exhibit 5.31. Free Rider Analysis

Total	Very important (5)	(4)	(3)	(2)	Very un-important (1)	(1 – FR)
Weight	1.00	0.75	0.50	0.25	0.00	-
Score	0.500	0.150	0.150	0.000	0.200	
Product	0.500	0.113	0.075	0.000	0.000	0.688

Exhibit 5.32 provides a second analysis of spill over. The share of furnaces replaced early comes from the consumer survey, but the years replaced early comes from the trade ally survey. The weighted average years replaced early using this approach is 1.783 years.

Exhibit 5.32 Spill Over Analysis

	Replaced early (%)	Years replaced early	Weighted average years replaced early
Yes	39.8	4.48	1.783
No	60.2	0.00	0.000
DK/NR	-	-	-
Total participants	-	-	1.783

6. Impact Analysis

6.1 Furnace Sales

As indicated above, trade allies were asked to provide information on their sales of furnaces. Average respondent sales for new dwellings increased from 31.4 units in 2000 to 36.7 units in 2001 and to 39.6 units in 2002. Average respondent sales for replacement furnaces increased from 39.9 units in 2000 to 48.4 units in 2001 and to 62.1 units in 2002. Assuming that our sample is representative of the broader market, this suggests quite strong growth in the furnace market. Trade allies were also asked to provide information on the composition of their furnace sales by type. Average respondent share of sales for high efficiency furnaces for new dwellings increased from 19% in 2000 to 25% in 2001 and to 37% in 2002. However there is some uncertainty about the estimate for new construction as the survey was based on program contractors and may not represent the overall new construction market. Average respondent share of sales for high efficiency furnaces for replacement furnaces increased from 27% in 2000 to 37% in 2001 and to 54% in 2002. This is consistent with a rapid shift towards a more efficient furnace market.

Exhibit 6.1. Average Sales per Firm by Furnace Type

	New dwellings (number)			Replacements (number)		
	Mid	High	Total	Mid	High	Total
2000	25.5	5.9	31.4	29.3	10.6	39.9
2001	27.7	9.0	36.7	30.4	18.0	48.4
2002	24.8	14.8	39.6	28.5	33.6	62.1

6.2 Market Transformation

Based on the trade ally survey, together with industry information, we have attempted to estimate trends in furnace sales for British Columbia from 1996 to 2002 as shown in Exhibit 6.2. Over the seven years covered by the analysis, furnace sales rose steadily from some 15,900 units per year in 1996 to some 22,100 units per year in 2002. During this period the number of non-condensing furnaces sold has remained fairly stable, with some fluctuations, at between 11,000 and 13,000 units per year. But the number of condensing furnaces has risen from about 4,000 units per year in the pre-program period to about 6,000 units in 2001 and perhaps as many as 11,000 units in 2001. Equally important the markets share of condensing furnaces has risen from about one-quarter of units sold in 1996 to about one-half of units sold in 2001. If the share of condensing furnaces in the total market continues at this level, we can view this as strong evidence in support of transformation of the residential furnace market.

Exhibit 6.2. Estimated Furnace Sales

	Total (units)	Non-condensing (units)	Condensing (units)
1996	15,900	12,000	3,900
1997	17,300	13,000	4,300
1998	16,400	12,400	4,000
1999	14,900	11,200	3,700
2000	15,500	11,700	3,800
2001	18,500	12,200	6,300
2002	22,100	11,000	11,100

6.3 Furnace Prices

Some concern has been raised that trade allies might try to capture part of the incentive by raising the prices of the high efficiency furnaces they sell. Analysis of customer cost information indicates that the average prices paid per high efficiency furnace including taxes were $3142 for participants and $3648 for non-participants buying high efficiency furnaces so that participants paid about $507 less than non-participants. However, this difference may be largely explainable because of differences in furnace capacity or house size.

Interviews with trade allies indicated that there are strong economies of scale so that normalizing prices is somewhat complicated. Nevertheless, we have attempted to normalize these prices on both a capacity and a square foot basis in Exhibit 6.3. On a capacity normalized basis, participants paid about $9.88 more per Mbtuh than non-participants. On a per square foot normalized basis, participants paid about $0.042 less than non-participants. Finally, discussions with some trade allies suggested that the incremental cost of a high efficiency furnace is about $ 100 per size increase. This appears to be born out by the price data in Exhibit 5.30 where the price difference between a 75 and 90 Mbtuh furnace is $ 91.

As shown on Exhibit 6.2, the non-participant furnaces appear to be about two sizes larger than the participants, which would account for approximately $ 200 of the price difference.

There is no evidence from this data that trade allies were increasing the selling prices of their furnaces to capture part or all of the incentive paid to program participants for the year 2002.

Exhibit 6.3. High Efficiency Furnace Prices (dollars)

	Participants	Non-participants	Difference
High efficiency (dollars)	$3141.60	$3648.40	506.80
Capacity (Btuh)	73,896	111,800	51%
Area (square feet)	1875	2125	13%
Cost per Mbtuh (dollars)	$42.51	$32.63	$9.88
Cost per square foot (dollars)	$1.675	$1.717	-$0.042

6.4 Energy Savings and Peak Reduction

To estimate energy savings, unit savings are multiplied by the number of gross participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio to provide the estimate of net savings.

Two sources of information was used for this analysis. The first was data from the customer survey, the second from the trade ally survey. The differences between the data is that the customer survey indicated a different period of time for early replacement and a different free rider rate. As shown in Exhibit 6.4, the estimated net savings are 36.9TJ for the first two years and 15.9TJ for subsequent years based on data from the customer survey.

Exhibit 6.4. Energy Savings – customer survey

	Unit savings (GJ)	Gross participants	Gross savings (TJ)	Net to gross ratio	Net savings (TJ)
Direct	9.59	2,785	26.708	0.595	15.891
Spill over	18.92	1,108	20.963	1.000	20.963
Annual - first two years	-	-	-	-	36.854
Annual - subsequent years	-	-	-	-	15.891

Exhibit 6.5 provides an alternative estimate of energy savings based primarily on information from the trade allies survey, unlike the estimate in Exhibit 6.4 which is based on information form the consumer survey. As before, unit savings are multiplied by the number of gross participants to get gross savings, and net savings are equal to gross savings times the net to gross ratio. However, we now use a different free rider rate and a different estimate of the duration of spill over savings. Estimated net savings are 39.3TJ for the first four and one-half years and 18.4TJ for subsequent years.

Exhibit 6.5. Energy Savings – trade ally survey

	Unit savings (GJ)	Gross participants	Gross savings (TJ)	Net to gross ratio	Net savings (TJ)
Direct	9.59	2,785	26.708	0.688	18.375
Spill over	18.92	1,108	20.963	1.000	20.963
Annual - first 4.5 years	-	-	-	-	39.338
Annual - subsequent years	-	-	-	-	18.375

It was felt that the trade ally survey provided better information on the remaining life of the furnace, due to the greater expertise of the trade relative to homeowners, and this estimate has been used in the report.

In order to estimate peak savings, we assume that heating load on any day is proportional to heating degree days for that day, so that in the coldest month (January) the average daily heating load is (annual heating load in GJ)*(monthly share of annual heating degree days for January)*(1/31 days). The change in peak day load is then estimated as the change in average daily load for January. Exhibit 6.6 calculates the weighted peak day heating load share for January using a representative weather station for each zone and the thirty-year typical meteorological year heating degree-day shares for January. Estimated peak day savings is then weighted peak day heating load share for January multiplied by net savings. Estimated peak day savings are 0.22TJ for the first 4.5 years and then 0.10TJ for subsequent years.

Exhibit 6.6. Peak Day Savings

Zone	Representative weather station	Zone customer share	Peak day heating load share	Weighted peak day heating load share	Peak day savings first 4.5 years (TJ)	Peak day savings subsequent years (TJ)
Zone 1	Vancouver	0.244	0.00501	0.00122	-	-
Zone 2	Burnaby	0.173	0.00511	0.00084	-	-
Zone 3	Surrey	0.280	0.00510	0.00143	-	-
Zone 4	Kamloops	0.117	0.00625	0.00073	-	-
Zone 5	Cranbrook	0.186	0.00667	0.00124	-	-
Total		1.000		0.00546	0.2148	0.1003

6.5 Carbon Dioxide Reductions

Natural Resources Canada and Terasen Gas use emissions factors of 50.45 tonnes of carbon dioxide per terajoule and 50.00 tonnes of carbon dioxide per terajoule respectively. Exhibit 6.7 shows the reductions in carbon emissions under the assumption of 50 tonnes per TJ.

Exhibit 6.7. Carbon Dioxide Emissions Reductions

	Net savings (TJ)	Emissions factor	CO_2 reductions (ktonnes)
Direct	18.375	0.05000	0.9188
Spill over	20.963	0.05000	1.0482
Total first 4.5 years	39.338	0.05000	1.9669
Total subsequent years	18.375	0.05000	0.9188

7. Conclusions

Conclusion 1. Rationale for the Heating System Upgrade Program. The rationale for the Heating System Upgrade Program is based on the following premise. By providing customers with information on the cost effectiveness of high efficiency furnaces combined with a financial incentive, customers will install high efficiency furnaces in larger numbers resulting in measurable reductions in energy consumption and carbon dioxide emissions. Detailed review of the input-output-outcome-impact chain for each program activity indicates that there are strong and plausible linkages for each part of this chain, confirming the logic of program design and the rationale for the Heating System Upgrade Program.

Conclusion 2. Customer and Trade Ally Awareness. Awareness of a program and its benefits are the first step in the chain of actions that may eventually lead to program participation. The share of respondents stating awareness of the program is 91% for participants and 41% for non-participants. All trade allies surveyed were aware of the Heating System Upgrade Program.

Conclusion 3. Customer and Trade Ally Satisfaction. Maintaining high levels of customer satisfaction is a key concern of program management and staff. Satisfaction with a variety of program components was rated on a five-point scale where one is not at all satisfied and five is very satisfied. Participants reported satisfaction levels averaging 4.0 or more for information on the rebate procedure, time period for purchasing an eligible furnace and application procedures. Non-participants reported satisfaction levels of 4.0 or more on information on the rebate program, application procedures and information about energy efficient furnaces. Trade allies reported satisfaction levels averaging 4.0 or more for information on the rebate procedure, application procedures to obtain the rebate, amount of the rebate and promotional activities of Shell Busey.

Conclusion 4. Program Barriers and Program Opportunities. Customers who purchased a standard efficiency furnace were asked why they chose a standard efficiency furnace instead of a high efficiency furnace. The most important reasons were: high efficiency furnace was too expensive, contractor recommended standard efficiency, and could not install because of size or location. Customers who purchased a high efficiency furnace were asked why they chose a high efficiency furnace instead of a standard efficiency furnace. The most important reasons were high efficiency furnace had lower gas costs, high efficiency furnace was more reliable, high efficiency furnace had desired features, availability of the rebate program and to have better and more efficient heating. From a customer perspective, the best months to offer an energy efficient furnace program were September, October, August and November.

Conclusion 5. Impact of Advertising and Promotions. Advertising and promotional activity is a key means of increasing program awareness and participation. For participants, the most important sources are: insert in Terasen Gas bill; heating contractor; radio advertisement and word of mouth. For, non-participants, the most important sources are: insert in Terasen Gas bill, heating contractor and mail advertisement. For trade allies, the most important sources of awareness in decreasing order of importance are: BC contractor direct mail package, furnace manufacturers, radio advertisements, Terasen Gas regular contact, Terasen Gas trade newsletter, customers, and industry associations. Given the pattern of first date of awareness, there is little evidence that the strong promotional push in October and November of 2002 had a significant impact on program awareness and participation. However, this conclusion should be tempered with the fact that consumers have imperfect recall of past decision making.

Conclusion 6. Impact of the Program on Sales and Market Share. Trade allies were asked to provide information on their sales of furnaces. Average respondent sales for new dwellings increased from 31.4 units in 2000 to 36.7 units in 2001 and to 39.6 units in 2002. Average respondent sales for replacement furnaces increased from 39.9 units in 2000 to 48.4 units in 2001 and to 62.1 units in 2002. Assuming that our sample is representative of the broader market, this suggests quite strong growth in the furnace market. Trade allies were also asked to provide information on the composition of their furnace sales by type. Average respondent share of sales for high efficiency furnaces for new dwellings increased from 19% in 2000 to 25% in 2001 and to 37% in 2002. Average respondent share of sales for high efficiency furnaces for replacement furnaces increased from 27% in 2000 to 37% in 2001 and to 54% in 2002. This is consistent with a rapid shift towards a more efficient furnace market.

Conclusion 7. Impact of the Program on Prices. Some concern has been raised that trade allies might try to capture part of the incentive by raising the prices of the high efficiency furnaces they sell. Analysis of customer cost information indicates that the average prices paid per furnace including taxes were $3239 overall, $3142 for participants buying high efficiency furnaces, $2337 for non-participants buying standard efficiency furnaces and $3648 for non-participants buying high efficiency furnaces. Participant and non-participants cost for high efficiency furnaces were normalized with respect to capacity and with respect to house area. There is no evidence from the data that trade allies were increasing the selling prices of their furnaces to capture part or all of the incentive paid to program participants for the year 2002.

Conclusion 8. Impact of Program on Energy Savings and Peak Demand. To estimate energy savings, unit savings are multiplied by the number of gross participants to get gross savings. Net savings are then equal to gross savings times the net to gross ratio to provide the estimate of net savings. Estimated net savings are 39.3TJ for the first 4.5 years and 18.4TJ for subsequent years. Estimated peak day savings is the weighted peak day heating load share for January multiplied by net savings and estimated peak day savings are 0.21TJ for the first 4.5 years and then 0.10TJ for subsequent years.

Conclusion 9. Impact of the Program on Carbon Dioxide Emissions. Using an emissions factor of 50 tonnes of carbon dioxide per terajoule yields an emissions reduction or carbon dioxide savings of 1.97 kilotonnes of carbon dioxide for the first 4.5 years of the program and 0.92 kilotonnes of carbon dioxide for subsequent years of the program.

Conclusion 10. Market Transformation. Ultimately the main goal of a demand side management program is to transform the market, that is to change demand side and supply side characteristics so that the efficient product is the product chosen by most purchasers. The evidence examined above suggests that although the market for residential furnaces is not yet transformed, substantial progress in the direction of market transformation has been made. At a time of growing sales of new and replacement furnaces, high efficiency furnaces have increased their market share from about one-quarter of sales in the pre–program period to about one–half of sales in 2002.

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
MATERIAL EFFICIENCY MEASURES

Since reaching a negotiated settlement on a 2004-2007 PBR with stakeholders, Terasen has initiated two material efficiency undertakings:

- The meter shop consolidation initiative
- The Utilities Strategy Project

1. MEASUREMENT TECHNOLOGIES FACILITIES CONSOLIDATION

a. Executive Summary and Introduction

Measurement Technologies, with a staff of 60, is responsible for maintaining the accuracy of metering devices for Terasen Gas, as well as providing daily energy consumption data to large commercial and industrial customers.

These responsibilities are divided into three main areas. The first involves the maintenance of approximately 770,000 meters installed at customer locations across the service territory in British Columbia. A portion of these meters are recalled annually for maintenance and verification of for measurement accuracy. Those meters that are verified as accurate, according to Measurement Canada's guidelines, are certified and made available for re-installation at customer locations. The second responsibility involves the procurement and certification of new meters to replace those scrapped and those required for customer additions. Finally, Measurement Technologies provides energy consumption data to large commercial and industrial customers that require daily meter readings to help better manage their energy use requirements.

During the past 4 years, the group has offered its services to third parties in an effort to gain income to offset costs and enhance economies of scale. Offering contestable services to third parties has provided additional spin-off benefits such as exposing employees to competitive tension and gaining valuable insight into market pricing for meter services. This expanded understanding of the marketplace has served as a focal point in identifying components within Measurement Technologies that should be resized, expanded, curtailed or eliminated. Terasen Gas has initiated a program to capture these identified potential efficiencies which is expected to be complete by the end of 2003. The one-time cost to implement the changes listed below is approximately $280,000 in O&M and $880,000 in Capital, with the resultant benefits estimated at approximately $700,000 in annual O&M savings and $450,000 in annual Capital savings for Terasen Gas.

b. Project Descriptions

i. Reduce Residential Meter Repair Capacity

Each year, approximately 43,000 residential gas meters are removed from service and, on a normalized basis, 50% of these meters are scrapped and replaced with new meters and the balance are repaired. Over time, the industry has moved away from full meter repair, in part due to low cost replacement meters, and has instead adopted a Level1 repair strategy for residential meters that are serviced. A Level1 repair is essentially an inspect and calibrate activity and any meter identified as requiring more extensive work is simply scrapped and replaced with a new device. Terasen Gas has kept in step with industry and has recently curtailed the low margin Level 2 and Level 3 residential meter repair activities. Since the Bainbridge Meter Shop was initially sized for full repair of Terasen Gas' residential meter fleet, an opportunity existed to resize the facility primarily for Level 1 meter repair.

In late 2002, a consultant was hired to examine the re-sized facility requirements and to ascertain whether these requirements could be accommodated within existing Terasen Gas owned facilities. The consultant's findings were in support of such a move.

The estimated cost to implement the alterations and the resultant benefits are discussed in Section (ii) below.

ii. Optimize Meter Shop Facilities

Terasen Gas presently operates a Meter Shop located in a 25,000 square foot company-owned facility in Penticton to service commercial-size gas meters. Meters not repaired in Penticton were serviced in a second Meter Shop which was housed in a leased facility located in Burnaby (the Bainbridge facility). The Bainbridge facility became significantly oversized once the strategy to reduce residential gas meter repair capacity was adopted (see Section (i) above).

A consultant was hired in late 2002 to assess meter shop facility requirements and to specifically examine the feasibility of exiting the Bainbridge leased facility and moving operations into company owned facilities. The consultant concluded that (with some building alterations) sufficient space could be made available to accommodate a resized operation presently housed at Bainbridge. The consultant recommended that all meter repair activities be relocated to Penticton creating a single Meter Shop. The consultant also recommended that meter warehousing, regulator servicing and the Bainbridge instrument trailer be relocated to the Burnaby Operations site where natural affinities to those activities exist. Both of these recommendations were the lowest cost options of the alternatives examined.

The one-time cost to implement the required building alterations was $217,000 in O&M and $820,000 in capital. The resultant benefits are estimated at $537,000 in annual O&M savings and $ 464,000 in annual capital savings.

iii. Optimize Office Facilities

For the past 8 years, Terasen Gas leased the entire 6th floor at the Commerce Court Building located at 4180 Lougheed Highway in Burnaby. The total footprint consisted of 14,721 square feet and was shared by Measurement Technologies (i.e. Terasen Gas), Terasen International and Terasen Utility Services. In the spring of 2003, Terasen Utility Services and Terasen International decided to move out of Commerce Court. The utility share of the floor (6,845 square feet) was no longer viable with the co-tenants vacating.

The Facilities Department examined various options to relocate Measurement Technologies from Commerce Court into company owned facilities. The most favourable option was to relocate a portion of the technical support group to the Penticton Meter Shop with the balance of staff moving to Surrey Operations.

The one-time cost to implement alterations was $ 66,000 in O&M and $61,000 in Capital. The resultant benefits are estimated to be $ 191,000 in annual O&M savings.

2. THE UTILITIES STRATEGY PROJECT

In September Terasen Gas Inc. (TGI) and Terasen Gas (Vancouver Island) Inc. (TGVI) launched a joint initiative to examine how operating efficiencies could be gained by harmonizing operating processes and management activities between the two utilities.

Approximately 60 management employees from the two organizations are actively engaged in the project in five functional teams and three oversight and support groups:

1. Field operations
2. Customer and Marketing
3. Information Technology
4. Human Resources
5. Finance and Regulatory
6. Communications
7. Policy
8. Program Management

The project's objectives include achieving a degree of operational integration that will:

- be broad in scope and scale, while respecting existing legal, regulatory and contractual obligations.
- result in common management across all regulated gas utilities.

- be fair and respectful to employees, customers, shareholders and the communities the Companies serve; and
- result in safe, sustainable & more effective, efficient gas utility operations for TGI and TGVI and related subsidiaries

The design principles and key assumptions the project teams are to base their recommendations on, include:

- Deploying a common business approach barring compelling reason to do otherwise.
- Seeking best practice solutions (must complement/fit with Terasen Gas IT umbrella).
- Minimizing conversion costs of historical data while retaining retrieval capability.
- Maintaining separate legal entities, rate bases, and rate design (TGI, TGVI, Whistler, Squamish).
- Ensuring cost efficiencies flow to both entities and proper cost allocation through the provision of corporate services to TGI/TGVI that deliver benefit to all from economies of scale.
- Expanding service contracts between entities while maintaining equitable, efficient cost allocations.
- Moving to common employer status with union bargaining units and developing common compensation philosophies for all employees, and
- Seeking to retain the best people from both organizations while shrinking the combined workforce.

As part of this initiative, a Voluntary Early Retirement Program was announced with eligible employees required to elect by November 7, 2003. At the present time teams are expected to provide high level organizational change recommendations by early November with staffing decisions made following confirmation of changes resulting from the early retirements.

Transition planning will commence in late November with the expectation that some employees will begin leaving the organization by the end of December 2003. At the present time, costs associated with the project have been limited to travel costs (which are nominal) for project team members between the Lower Mainland and Vancouver Island and Consulting fees paid to Western Management Consultants and Turnkey Management Consultants who have been providing Program Management support and guidance. The forecast expenditures for 2003 will be approximately $270,000.

Until organizational design recommendations have been approved and implementation planning completed, the Company will not be in a position to quantify the bulk of the related restructuring costs for severance, relocation, facilities rationalization, etc.

Similarly, the determination and realization of benefits will depend in part on the speed at which the two companies can complete the transition to the new structure. Project teams have been challenged to design the most efficient structures and processes that will ensure that safety, reliability and customer service levels will be maintained. Given the significant degree of streamlining that has occurred in each organization prior to the initiation of this project, it is expected that savings will be in the range of 5-10% of the combined cost structures of the functional units being examined, excluding those costs fixed by contract. It is also anticipated that the savings to be achieved will be more heavily weighted to back office support units rather than field operational units.

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
REPORT ON THE ESTABLISHMENT OF INCENTIVE MECHANISM FOR REDUCING UNCONTROLLABLE / PARTIALLY CONTROLLABLE EXPENSES

The 2004 – 2007 Multi-Year PBR Settlement addresses at several places the issue of establishing incentive mechanisms for reducing uncontrollable or partially controllable costs. On Pages 15 and 16 of Appendix A to BCUC Order No. G-51-03 the Settlement indicates that the Company is to have a positive incentive around provincial and municipal government taxes, fees and expenses and that a specific mechanism was agreed to regarding property taxes. It further states that the Company or interested parties (intervenors/Commission staff) may bring forward any new ideas around positive incentives for partially controllable expenses to Annual Reviews.

The Company's main focus since the July 29, 2003 Commission approval of the 2004 -2007 Settlement has been on the material efficiency initiatives described in Section B, Tab 4. The initiatives described there represent material opportunities for ongoing benefits for the customers of Terasen Gas Inc. and Terasen Gas Vancouver Island. While the Company intends to develop proposals for incentive mechanisms for uncontrollable or partially controllable costs these have not been extensively developed to this point. The discussion below deals with the approved property tax mitigation incentive program and a proposal for cost mitigation / revenue generation by improving utilization of utility assets.

<u>Property Tax Cost Mitigation Plans</u>

For 2004 anticipated property taxation mitigation plans are based on preemptive strategies by Terasen Gas; with the goal of minimizing property tax risks and cost pressures to customers. Many of the savings projected in this report are based on assurances with various assessment offices, or taxation authorities as a result of preemptive activities over the past several years. However, until the rolls are produced, or legislation is amended, decreases (or increases) cannot be confirmed.

1. We are currently engaged in discussions with the Indian Taxation Advisory Board (ITAB) to reduce the significant increase in property tax rates by the Lower Similkameen Band in 2002. Tax rates increased from $ 31.9 to $61.2/$1,000 in that year. In 2002 this resulted in an annual increase of $63,600 (or 51.5%) in property taxes.

2. An agreement has been reached on new regulated transmission pipeline rates in early 2003. Based on Terasen Gas' 2001 transportation pipeline inventory we are anticipating an average increase of about 13.6%. While a 13.6% increase in rates seems high, it should be noted that pipeline rates have only increased by 10 to 15% from 1986 to 2003. In addition, initial pipeline rates presented by BC Assessment to Terasen Gas and CEPA would have resulted in an increase of over 44% in the assessments. Through

negotiation we are able to avoid costly appeal proceedings that likely would have resulted in changes to legislation.

3. As part of the new agreement we have been given assurances by BC Assessment that they will use a 3 year phase in as permitted in the act. Without the negotiated phase in Terasen Gas would pay additional taxes of approximately $735,000 in 2004, and $368,000 in 2005.

4. Currently evaluating the merits of a property assessment appeal based on Supreme Court of British Columbia case between Assessor Area 27 and Burlington Resources. If successful, property taxes will be reduced by $612,000 in 2004.

5. In August, 2003 we met with the Assessor in the Nelson/Trail area regarding several communication towers purchased from AT & T. The assessment for the Granite mountain tower was brought to their attention. We are hoping to have the assessment reduced by at least 50%. A 50% reduction would result in annual savings of approximately $10,000.

6. Where possible we endeavor to pre negotiate values for the upcoming roll year. In 2004 we have provided input on the newly constructed Armstrong Compressor Station. It is impossible to determine any savings using this technique, however, it has been our experience that values produced are more reasonable, in addition, costly appeal proceedings are avoided.

7. It is not possible to determine the number or complexity of issues relating to the 2004 roll until it is produced, and analyzed. We normally receive all assessment values in early January, and each roll is thoroughly reviewed to ensure inventories are correct, and values are reasonable, and in line with other similar properties. Any rolls that are questionable are appealed.

8. When property tax payments are made in July of each year we scrutinize tax bills to ensure that municipalities are not applying taxes incorrectly, or exceeding the Utility Rate Cap established by regulation ($40 / $1,000 or 2.5x the Business/Other rate). We recognized that many of the tax savings made here are nominal in value in the short-term; they have the capacity to become cumulatively significant. Experience has shown that dealing with taxation issues while they are minor is less likely to result costly court challenges, and potential changes to tax policy to protect municipal revenues.

9. We are actively involved with a variety of groups specializing in Local Government taxation. These include the Canadian Property Tax Association, the Vancouver Board of Trade, and the Canadian Energy Pipeline Association. We have been directly involved in numerous submissions to the Provincial, and Municipal Governments attempting to promote equity and fairness in the taxation of Business, Industrial, and Utility properties. Most recently we were directly involved in 3 different submissions on the Community Charter.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
REPORT ON THE ESTABLISHMENT OF INCENTIVE MECHANISM FOR REDUCING UNCONTROLLABLE / PARTIALLY CONTROLLABLE EXPENSES
($000)

			Before Mitigation Measures		After Mitigation Measures		Proposed Allocation of Tax Savings for Each Year Impacted		
							100%	90%	10%
Item	**Preemptive Strategy**	**Year(s) Impacted**	**Assessment**	**Taxes**	**Assessment**	**Taxes**	**Total**	**Customer**	**Company Incentive**
1	Discussion with the Indian Taxation Advisory Board (ITAB) to reduce property tax rates on the Lower Similkameen Indian Band. Tax Rates increased from $31.8943/$1,000 to $61.2000/$1,000	2004 to 2007	$2,007	$64	$2,007	$123	$59	$53	$6
2	Agreement reached on new regulated transportation Pipeline Rates. Terasen Gas actively participated with CEPA (Canadian Energy Pipeline Association) in establishing updated Commissioner's Rates. Through the rate negotiation process, we requested BC Assessment adopt a 3 year phase-in which may be used at the Commissioner's discretion. We have been given assurances by BC Assessment that the phase-in will be allowed. (Note Phase-in is now an allowed in the Assessment Act, but is solely at the discretion of the Assessment Commissioner. (Note: Terasen Gas is not a member company of CEPA) Rates produced by the initial model from BC Assessment would have resulted in an overall increase of 44% rather than 13.64% based on the negotiated rates assuming rates implemented in their entirety in 2004, as was done in 1986/1987 when original rates were set. Tax rate estimated at $25.0000 / $1000 (Excludes 1% of Revenue Taxes)	2004 to 2007	$466,183	$11,655	$367,396	$9,185	$2,470	$2,470	$0
3	Negotiated with BC Assessment to Utilize Phase in provision allowed in Assessment Act at the discretion of the Assessment Commissioner.	2004	$367,396	$9,185	$338,000	$8,450	$735	$662	$73
		2005	$367,396	$9,185	$352,698	$8,817	$368	$331	$37
		2006	$367,396	$9,185	$367,396	$9,185	$0	$0	$0
4	Currently evaluating the merits of a property assessment appeal based on Supreme Court of British Columbia case between Assessor Area 27 and Burlington Resoures. Decision handed down June 11, 2003.	2004 to 2007		$1,140		$528	$612	$551	$61
5	Met with BC Assessment (Nelson/Trail) to discuss the valuation of towers purchased from AT &T. Assessment for Granite Mountain was brought to their attention, We are anticipating a reduction around 50% of the assessment value. Total 2003 Mill Rate $38.5812 / $1000	2004 to 2007	$440	$17	$220	$8	$9	$8	$1
6	Pre-roll negotiation of property assessments with BC Assessment on newly constructed facilities such as the Armstrong Compressor Station. It is not possible to determine any savings using this technique as there is not baseline (i.e. what BC Assessment would have valued the property at in absence of pre-roll negotiation on new facilities). It has been our experience that assessment values achieved in this manner are more reasonable, and avoid any costly appeal proceedings.	2004 to 2007					-	-	-
7	Each year we review all assessment notices to ensure inventories and values are correct and reasonable. It is not possible at this time to identify all that may require closer scrutiny, and / or appeal until the roll for the coming year is received in January of each year	2004 to 2007					-	-	-
8	Scrutinize property tax payments to ensure municipalities are applying rates correctly, and abiding by the rate cap. Experience has shown that dealing with taxation issues while they are minor in nature is less likely to result in costly court challenges and potential changes to tax policy designed to protect municipal revenues.	2004 to 2007					-	-	-
9	Actively involved with a variety of groups specializing in Local Government Taxation. These include the Canadian Property Tax Association, the Vancouver Board of Trade, and the Canadian Energy Pipeline Association. We have been involved in numerous submissions to Provincial and Municipal Governments attempting to promote equity and fairness in the taxation of Business, Industrial, and Utility properties. Most recently we were directly involved in 3 different submissions on the Community Charter.	2004 to 2007					-	-	-
						Totals	$4,253	$4,075	$178

Notes
1 All tax and assessment savings based on the 2003 Actual Assessment and Taxes.
2 Pipeline savings are based on cost avoidance strategies. That is, based on information and calculations of proposals put forward by BC Assessment.
This assumes that involvement by pipeline companies, including Terasen Gas directly affected the final rates.

At the October 15, 2003 Customer Advisory Council meeting, a participant suggested that the level of the property tax incentive (10%) was insufficient to encourage the Company to vigorously pursue savings in this area for customer benefit, and further suggested that the incentive should be increased to 25% of demonstrable savings. The Company agrees that the suggested modifications would provide even greater incentive to pursue such benefits and should be resolved at the Annual Review.

Utility Asset Utilization Proposal

Terasen Gas has been exploring a number of possible opportunities with third parties to improve or expand utilization of its above and below ground active and inactive assets in endeavours generally characterized as multi-utility in nature. These opportunities involve the lease or sale of Terasen Gas assets in order to capture latent value beyond that associated with their primary use as gas distribution assets. Examples of these opportunities include:

- Leasing space in inactive pipelines to telecommunications companies for insertion of fibre optic cables;
- Leasing space in live natural gas pipelines to telecommunications companies for insertion of fibre optic cables;
- Selling inactive pipelines to telecommunications companies for their use in expanding their telecommunications infrastructure;
- Leasing space at Company owned work sites (buildings, muster stations, etc.) for telecommunications or other utility purposes;
- Sale of utility land assets determined to be surplus.

Considerable effort is required to bring to fruition the development of proposals. Economic analysis and business case development of these matters are at preliminary stages and the overall magnitudes of the opportunities are unknown. There are considerable upfront development costs since these are for the most part new ventures that are untested in B.C., They are multi-jurisdictional in nature and involve, in some cases, new and developing technologies. The potential for significant upfront development costs in these ventures is an impediment under the PBR since there is risk that payback and return will not be achieved.

The potential benefits to the customers of Terasen Gas lie in several areas such as:

- future revenue streams from any leasing arrangements that can be brought to completion;
- for asset sales of inactive pipe or surplus land, a source of income through the gain made on the sales; and
- a lower future rate base from sales of any assets that are in rate base at the time of sale.

Given the uncertainties associated with the magnitude of these opportunities and the potential large upfront development costs Terasen Gas proposes the following as an incentive mechanism to seek these asset utilization efficiencies.

- Revenues from transactions of the sorts described above will not be included in the miscellaneous revenue forecast to be updated each year for the Annual Review.
- Revenues from lease arrangements will be subject to 50/50 sharing between customers and shareholders for the term of the lease.
- Revenues from the sale of land determined to be surplus or inactive pipe will be booked as recorded utility revenues in the year the transaction is completed and will thereby be subject to 50/50 sharing with customers through the Earnings Sharing Mechanism in the PBR.
- Incremental development costs associated with arrangements of this nature will be treated as normal O&M expenses and will also be subject to 50/50 sharing through the PBR Earnings Sharing Mechanism.

Individual programs proposed under the load acquisition incentive mechanism will be subject to an economic test to ensure that program participants are not subsidized by non-participants. Each program will have in place a mechanism that measures the level of participation for that program. A typical method would involve an incentive redeemed through a coupon. The net benefit of each program will be shared between the customers and the Company.

In order to overcome the challenge of small loads relative to program and incentive costs, the Company is exploring opportunities to partner with third parties who would also benefit from builders or customers choosing gas for their energy needs. Terasen Gas has had some success in partnering with BC Hydro on Vancouver Island, and looks forward to developing more opportunities in the near future.

Terasen

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October 30, 2003

Randy Jespersen
President
Terasen Gas Inc.
Surrey Operations Centre

Subject: Review of Terasen Gas Inc's Compliance with the BCUC Code of Conduct and Transfer Pricing Policy.

Internal Audit Services has recently completed a review of compliance with the Terasen Gas Inc's Code of Conduct and Transfer Pricing Policy for the Provision of Utility Resources and Services (the BCUC Policies). This review was conducted to enable Terasen Gas Inc. (TGI) to meet the requirements of Part 7 of each of the BCUC Policies. The requirements state that "Terasen Gas Inc. will monitor employee compliance with this Code by conducting an annual compliance review, the results of which will be summarized in a report to be filed with the Commission within 60 days of the completion of this review".

Background

The BCUC Policies were issued in 1997 to provide guidance to Terasen Gas Inc. employees on interactions with Non-Regulated Business ("NRBs"). NRBs are defined as "an affiliate of Terasen Gas Inc. not regulated by the Commission or a division of Terasen Gas Inc. offering unregulated products and services". Since that time TGI has worked to create processes and procedures that would ensure compliance with these policies.

As a result of the 2004 – 2007 PBR Settlement, the Commission will conduct Annual Reviews with TGI and interested parties. TGI will hold its first Annual Review in November of 2003. Prior to the first Annual Review, TGI's external auditor will review the work performed by Terasen Inc.'s Internal Audit Services (IAS). The external auditors will provide a report of Terasen Gas Inc's compliance with the Code of Conduct and Transfer Pricing Policy consistent with section 8600 of the CICA Handbook "Review of Compliance with Agreements and Regulations".

Objectives, Scope and Approach

Consistent with prior year, the objectives of the review were to ensure that the business processes in place facilitate and support compliance with the BCUC Policies.

Our review was made in accordance with Canadian generally accepted standards for review engagements, as detailed in the Canadian Institute of Chartered Accountants Handbook. In addition to enquiries and discussions with relevant personnel, our approach included substantive procedures related to the requirements regarding sharing of customer information, cross charging time to NRBs for services performed and special arrangements provided to TGI customers by NRBs.

Conclusion

Based on the results of our work for the period of January 1, 2003 to September 30, 2003 and subject to our comments below, nothing has come to our attention that indicates Terasen Gas Inc. is not in compliance with the BCUC Policies or does not have appropriate business processes in place to facilitate and support compliance with such policies.

On September 22, 2003 a formal complaint was filed with BCUC by the Heating Ventilating Cooling Industry Association of B.C. alleging TGI's non-compliance with the Commission's February 4, 2003 Decision on the Company's 2003 Revenue Requirements Application. The Commission requested that the Company provide a response to the complaint by November 24, 2003 and a reply from the complainant by December 4, 2003 following which the Commission will further consider the matter.

Management is currently preparing its response in accordance with the Commission's request and believes it can demonstrate compliance with the Commission's Decision.

Results of Work

As part of the review, Internal Audit Services selected a random sample of 65 employees who were asked to respond to a survey on compliance with the BCUC Policies. Every 18th employee on the Terasen enterprise wide listing was selected. The sample size was selected to meet a 95% confidence level that errors in the population would not exceed a 5% threshold. Responses were received from all 65 of the employees surveyed. No compliance violations were identified, although two employees noted exceptions which have been summarised below:

Two employees indicated that they were not aware of the requirements of the BCUC Policies regarding charging time for work performed for NRBs. However, these employees have confirmed that they did not perform any NRB related work during the period in review. In the normal course of their duties, likelihood of these employees being involved in NRB work is low to nil.

Internal Audit Services has addressed these individuals directly at Management's request on the importance of this requirement. In addition, it is Management's intention to tailor another communication directed at employees with low likelihood of performing work for NRBs to ensure awareness across the entity.

In addition to the work described above, IAS noted that TGI Management has implemented or is in the final stages of implementing process improvement recommendations as per the 2002 Review.

Recommendations

Based on the results of the work we performed for this review and discussions with Scott Thomson, Vice President, Finance and Regulatory Affairs, we believe the following process improvements will increase awareness and compliance with the BCUC Policies.

1. TGI to finalize their work on implementing procedure requiring all computer users to acknowledge understanding and compliance with the Code of Conduct and Transfer Pricing on a quarterly basis through a user acceptance screen during the network login process. We have been advised by Management that the implementation date is expected to be the end of November 2003.
2. Managers will be required to acknowledge that they have appropriately conveyed the requirements and significance of the BCUC Policies to all their employees through an annual sign-off.
3. Continue to communicate and reinforce the requirements of the BCUC policies to all employees.

We wish to express our appreciation to all Terasen Gas Inc. employees who participated in this review for their assistance and co-operation during the course of our review. Please contact me if you should have any questions or would like to discuss further the substance of our review.

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Senior Auditor, Internal Audit Services
Terasen Inc.
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REVIEW ENGAGEMENT REPORT

Mr. Scott Thomson
Vice President of Finance and Regulatory Affairs
Terasen Gas Inc.

We have reviewed Terasen Gas Inc.'s compliance as at and for the nine months ended September 30, 2003 with its Transfer Pricing Policy For Provision of Utility Resources and Services (the "Transfer Pricing Policy") and the Code of Conduct For Provision of Utility Resources and Services (the "Code of Conduct"), both dated August 1997. Our review was made in accordance with Canadian generally accepted standards for review engagements and accordingly consisted primarily of enquiry, analytical procedures and discussion related to information supplied to us by the Company, including a review of Terasen Gas' Internal Audit Services report on compliance with the Transfer Pricing Policy and Code of Conduct dated October 30, 2003 and their work performed in connection with the report.

A review does not constitute an audit and consequently we do not express an audit opinion on this matter.

The British Columbia Utilities Commission (the "Commission") has received a complaint filed by the Heating Ventilating Cooling Industry Association of B.C. alleging non-compliance with the Commission's February 4, 2003 Decision on the Company's 2003 Revenue Requirements Application, including its compliance with the Transfer Pricing Policy and the Code of Conduct. The Commission has established a process in order to consider whether the complaint has merit and any further investigation would be subject to its determination on the matter, including whether any instances of non-compliance had occurred.

Except for the effect of adjustments, if any, which we might have determined to be necessary had the Commission completed its review of the complaint, as described in the preceding paragraph, based on our review, nothing has come to our attention that causes us to believe that the Company is not in compliance with the Transfer Pricing Policy and Code of Conduct.

KPMG LLP

Chartered Accountants

Vancouver, Canada
October 30, 2003

Variable Interest Entities

On September 16, 2003 the Accounting Standards Board of the CICA decided to delay the implementation of the accounting guideline issued in June 2003 which would have mandated the consolidation of Variable Interest Entities for the Company effective January 1, 2004. This means that the synthetic lease in place to finance the Coastal Facilities project will need to be recorded in the Company's balance sheet and no longer be treated as an operating lease, effective January 1, 2005 instead of a year earlier as a result of the decision to delay the implementation. The Company expects to end the Coastal Facilities synthetic lease arrangement and plans to file a separate application for Commission approval to include the Coastal Facilities assets in rate base effective January 1, 2005. The impact of this change is not reflected in the financial schedules and projected rates included in this Application, however, when the Coastal Facilities assets are included in rate base an adjustment to customers' rates will be required.

Separation of Terasen Inc.
and Creation of the Corporate Centre

October 31, 2003

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1.0 Introduction

This report sets out the plan to establish a Corporate Centre at Terasen Inc. to provide the functions that are traditionally provided by a corporate head office. The creation of the Corporate Centre will enable Terasen Gas to continue to benefit from the centralization of the highly specialized skills of employees currently providing those services at Terasen Gas. As the Terasen group of companies grows, the Corporate Centre will be able to maintain an optimal level of resources and avoid duplication of work. It also provides greater transparency in separating the operating costs of the Corporate Centre from the Terasen group of companies including Terasen Gas.

Consistent with the direction set out in the 2003 Revenue Requirements Decision, this report has three objectives:

(1) to set out the plan to transfer those Terasen Gas staff, resources and responsibilities from Terasen Gas to the Terasen Inc. Corporate Centre;

(2) to define the services to be provided and the corporate charges for those services; and

(3) to provide a business case for the provision of corporate services to Terasen Inc. by Terasen Gas.

In support of these objectives, the report indicates which assets will be transferred from Terasen Gas to the Corporate Centre and describes the service agreement between Terasen Gas and Terasen Inc. for the provision of corporate services.

The report includes a report prepared by Deloitte & Touche that presents a framework based on generally accepted methods of allocating corporate services costs to subsidiaries. This framework is used as the basis for the allocations of Corporate Centre costs.

1.1 Corporate Centre Overview

A Corporate Centre pools those services performed within organizations that can be defined as non-core activities where significant scale benefits can be achieved from conducting them centrally. Services that are typically provided through a Corporate Centre include: corporate planning and governance functions including strategic planning, internal audit, risk management; corporate financial services such as treasury, investor relations, external reporting and consolidation, and tax; and various other services including legal, insurance services, and human resource compensation and planning.

Separate Corporate Centres are generally established when companies grow sufficiently in size to include businesses operating in different markets, geographic and regulatory jurisdictions such that economies of scale can be realized through centralization. Savings are achieved by avoiding the duplication of resources that would result by replicating service provision at each business. Corporate Centres also achieve greater purchasing power when outsourcing resources by virtue of their larger size and bargaining strength. Furthermore, centralization provides access to highly skilled specialized services that would not be economic to support for a single smaller business. For a regulated utility such as Terasen Gas, these benefits flow-through to customers through lower cost of service requirements and maintaining service quality.

The benefits of scale economies must be balanced against the need for individual operating autonomy and the unique requirements of individual businesses within a corporate group. As the scale and scope of the group of companies grows, the economies of scale benefits of centralizing the provision of certain services through a Corporate Centre are enhanced. In this regard, it is important to note that the economies of scale relating to centralization have already been realized at Terasen Gas since these functions are currently centralized at Terasen Gas. Moving the services to a separate Corporate Centre will neither erode nor add to the economies of scale currently being achieved. However, over time and as the Terasen Inc. group of companies continues to grow, it is expected that additional economies will be realized which would result in a reduction in the charges from Terasen Inc.

In addition to the economy of scale benefits discussed above, Corporate Centres provide greater transparency as to the costs of running each of the businesses within the group of companies. As circumstances change in the future through continued growth across Terasen Inc., this separation will provide greater clarity to Terasen Gas and interested parties as to the services and service levels provided and the value of additional economies of scale.

1.2 2003 Revenue Requirements Application Decision

The 2003 Revenue Requirements Application of Terasen Gas Inc. (then known as “BC Gas Utility Ltd.” and in this report referred to as “Terasen Gas”) was filed in June 2002. That Application sought approval of rates for 2003 and also sought to establish a base year for the negotiation of a multi-year Performance Based Ratemaking (PBR) plan. The British Columbia Utilities Commission (“Commission” or “BCUC”) review process examined the capital and operating costs of Terasen Gas including the charges for corporate services either provided internally or by way of services provided by Terasen Inc. (then known as “BC Gas Inc.” and in this report sometimes referred to as “Inc.”).

The Commission issued its Decision on Terasen Gas’ 2003 Revenue Requirements Application (“Decision”) on February 4th, 2003. In the Decision, the Commission approved the operating and maintenance costs allowed for recovery in rates, which included a reduction to the 2003 Revenue Requirement for Terasen Gas of approximately $600,000 reflecting a reduction in the general allocation of Terasen Inc. General and Administrative costs to Terasen Gas. In addition, the Commission directed Terasen Gas to provide a plan for the separation of the pensions, salaries and expenses of Terasen Inc. staff from the Terasen Gas pensions, salaries and expenses. This would result in certain corporate services functions, which had previously been provided by Terasen Gas and cross-charged to Terasen Inc. and its subsidiaries according to the terms of the Code of Conduct and Transfer Pricing Policy, to be transferred to Terasen Inc. and then contracted back to Terasen Gas through a Corporate Services Agreement. The Decision also directed Terasen Gas to identify any services provided by Terasen Inc. to Terasen Gas, including the cost of the service and to provide a supporting business case for the contract from Terasen Inc. The establishment of a Corporate Centre at Terasen Inc. is consistent with the direction to clearly separate the Terasen Inc. staff and resources from those core to Terasen Gas.

The Decision did not make any determinations as to which specific services should be separated but indicated that it is no longer appropriate for the salaries and related costs of Terasen Inc. employees to be paid by Terasen Gas. In responding to the Decision, Terasen Gas has taken the approach that those services that relate primarily to Terasen Inc. or non-utility functions should be transferred out of Terasen Gas. Further, that any economies of scale achieved through the provision of these services at Terasen Gas should be retained when the services are transferred to Terasen Inc. and contracted back to Terasen Gas. Therefore, the total value of any services transferred from Terasen Gas to Terasen Inc. should be charged back to Terasen Gas at no more than the level of costs approved in the 2003 Revenue Requirement Decision adjusted for appropriate inflation growth and productivity. The transfer of staff and related capital and operating costs does not adversely affect the Terasen Gas cost of service since the transfer of costs to Terasen Inc. is offset by the contract back to Terasen Gas for the continued provision of those services as approved in the 2003 Revenue Requirement. By clearly defining the services currently provided in this report, Terasen Gas is assured that there will be no erosion of services or service levels provided through the Corporate Centre. This approach ensures that in complying with the direction to establish a separate Corporate Centre, there will be no adverse impact on Terasen Gas or its customers.

2.0 Background

In the past, most employees that provided services to Terasen Inc. were employees of Terasen Gas. As Terasen Inc. grew and the activities of its non-regulated and petroleum transportation businesses increased, more Terasen Gas personnel time and resources were spent supporting these activities. In 1993, the Commission approved the creation of a holding company and established a Code of Conduct and a Transfer Pricing Policy for the provision of Terasen Gas resources and services to Terasen Inc. and other businesses. In accordance with these policies, time spent by Terasen Gas employees working on Terasen Inc. and other businesses was charged directly to these subsidiaries. These policies ensured that Terasen Gas customers benefited through the sharing of economies of scale associated with cross charges recovered from those companies for the provision of corporate services. Terasen Gas and the other businesses also benefited as costs and skills expertise were shared amongst them in an efficient manner. The revenues recovered from cross charges to non-Terasen Gas businesses reduced the operating and maintenance costs and revenue requirement of Terasen Gas.

Although some portion of Terasen Gas personnel's time was effectively being outsourced to the holding company and its subsidiaries, these employees continued to provide service to Terasen Gas and as such were first and foremost considered Terasen Gas employees.

When time was spent directly on Terasen Inc. or non-Terasen Gas business, time was directly charged to them. Employees also spent time on activities which benefited both Terasen Gas and Inc. and its subsidiaries and charged this time to the Inc. General & Administrative account. This time was then allocated between Inc. and Terasen Gas using a formula based on the arithmetical average of revenues, earnings and assets. During 1993 to 2000, 80% of this time was allocated back to Terasen Gas. This allocation was reduced to 70% in 2002 and subsequently to 50% in 2003, as directed by the Commission in the 2003 Decision.

As Terasen Inc. has continued to grow and expand its non-Terasen Gas businesses, the time charged for work performed by Terasen Gas employees for Terasen Inc. and the other businesses has increased. This growth has made it increasingly important to increase the transparency and separation of Terasen Inc. and Terasen Gas functions while still retaining the economies of scale that had been achieved through centralization. In 2001, all personnel that were substantially dedicated to Terasen Gas were moved to the Surrey Operations Centre. Employees who performed shared services work for both Terasen Gas and Terasen Inc. and its subsidiaries remained at the downtown office. The functions that stayed at the 1111 West Georgia location were: Office of the CEO, Office of the CFO, Corporate Controller and External Reporting, Treasury, Tax, Financial Planning, Legal, Corporate Secretary, Enterprise Risk Management, Planning & Development, Human Resources, Public and Government Affairs and Internal Audit.

With the subsequent acquisitions of Centra Gas BC and Centra Whistler, the completion of Corridor Pipeline and the acquisition of a share of the Express pipeline system, Terasen Inc. has grown to the extent that a separate centralized corporate services centre is a cost effective approach to delivering services to the operating companies and allows the benefits of scale economies to continue to be realized by Terasen Gas and its customers.

3.0 Description of Corporate Services Required

Terasen Gas has determined that the following corporate centre services are required in order to meet its operating requirements. Many of these services relate to policy, strategy and governance activities in addition to high value skills delivery in specialized areas. Some of these services such as legal services, can be directly allocated based on direct charging of time whereas some of the services such as governance and strategic planning support are more appropriately recovered via an allocation process. These services would be required if Terasen Gas existed as a separate stand-alone entity, however, by virtue of the Corporate Centre, these costs can be spread more broadly across all of the Terasen group of companies to the benefit of Terasen Gas.

The Corporate Centre Services contract includes the following services to be provided by employees of the Corporate Centre:

<u>General Governance & Oversight Services</u>

In addition to the specific services provided for below, Terasen Gas receives the benefit of the expert advice and experience of Terasen Inc. executives who spend their time working on various committees including the Executive Committee (comprised of the CEO and senior vice presidents of Terasen Inc. as well as the heads of each operating company and the General Counsel), the Risk Management Committee and the Operating Committee.

<u>Office of the CEO</u>

The role and function of the Chief Executive Officer to Terasen Gas is provided by the CEO of Terasen Inc. The CEO office provides Terasen Gas with:

(1) All Board of Director governance and liaisons to direct development and implementation of Terasen Gas' strategic, operational and capital plans;

(2) Governance assurance that controls are in place to ensure the assets of the Company are safeguarded and optimized in the best interests of shareholders, customers and other stakeholders;

(3) Alignment and communication of the vision and direction of Terasen to employees and other stakeholders and the role of Terasen Gas in that vision and direction;

(4) Executive level succession planning and development to prepare and maintain exceptional leadership; and

(5) Act as the principal spokesperson in maintaining close communication with government, shareholders, the public and the financial markets.

Office of the CFO

The role and function of the Chief Financial Officer to Terasen Gas is provided by the CFO of Terasen Inc. The CFO office provides Terasen Gas with:

(1) Policy direction and oversight of services related to key financial areas including Treasury, Investor Relations, External Reporting, Financial Planning, Taxation and Internal Audit;

(2) Develop and implement required financing plans;

(3) Oversee the understanding, communication and adherence to accounting and securities disclosures, policies and practices;

(4) Maintain key contact relationships with debt and equity investors and investment bankers; and

(5) Lead financial elements of regulatory processes.

Treasury and Cash Management

(1) Finance Terasen Gas by preparing financing plan and recommend timing of debt and equity financing;

(2) Provide derivative management advice;

(3) Maintain investment banker and debt investor relationships;

(4) Maintain treasury related controls and compliance;

(5) Cash management, and cash forecasting;

(6) Ensure availability of short-term funds;

(7) Maintain banking and money market relationships;

(8) Arrange short term credit facilities and negotiate banking service fees;

(9) Provide education and related materials from training courses and seminars attended by Treasury staff;

(10) Maintain capital structure and provide access to financing alternatives; and

(11) Provide interest rate and foreign exchange rate forecasting.

Investor Relations

(1) Equity analyst communication;

(2) Investor and Shareholder communication;

(3) Assist in preparation of quarterly information packages, as required; and,

(4) Quarterly press release coordination.

External Reporting and Consolidation

(1) Consolidation and preparation of monthly financial statements for Terasen Gas and preparation of quarterly interim reports and annual audited financial statements;

(2) Preparation of monthly reporting journal entries (consolidation, tax, accruals, etc.), analytical reviews of accounts and monthly financial review package

(3) Preparation of analysis required for prospectus and other security filing documents as requested by Treasury Department and senior management;

(4) Preparation of quarterly report to the Audit Committee;

(5) Compilation of information in response to a variety of enquiries from operations, senior management and external bodies, such as the BCUC, external auditors and government agencies;

(6) Research current and emerging accounting policies in Canada and US;

(7) Direct response to accounting authorities in both Canada and US with respect to exposure drafts;

(8) Provide accounting policy advice for such issues as consistency of presentation, alternative treatments and resolution of complicated accounting policies and ensure compliance with Generally Accepted Accounting Principles;

(9) Representation in the CGA accounting task force where matters of national accounting standards and regulated company operations are considered and assessed; and

(10) Accounting advice and assistance as required.

Corporate Financial Analysis and Capital Management

(1) Preparation and maintenance of the five year forecasting model used for strategic planning process and in the annual budgeting process

(2) Provide financial analysis support during regulatory initiatives and evaluation of projects and new initiatives; and

(3) Provide project management and /or due diligence support where required.

Taxation Services

(1) Prepare year-end and quarterly tax provisions including preparing tax calculations and working papers for current and FIT expense, preparing the necessary journal entries, assisting auditors with external audit review, preparing tax notes to the financial statements and analyzing the taxes payable/receivable account;

(2) Prepare tax returns and all tax compliance work for Terasen Gas including identification and research technical issues, filing necessary elections and agreements, requesting post filing adjustments, and reviewing assessments and interest calculations;

(3) Calculate corporate tax installments and arrange payment;

(4) Prepare tax calculations in support of rate cases and annual reports to the BCUC;

(5) Manage GST and PST, including reviewing and filing returns, identifying issues and researching technical enquiries, coordinating filing of necessary elections, responding to queries on the application of GST or PST to particular transactions, training employees on the application of GST or to revenues and disbursements and advising employees of GST changes;

(6) Manage tax implications of payroll and employee benefits including researching and advising on taxable benefits, CPP, UIC, payroll tax issues, company pension plan issues, and preparing or reviewing taxable benefits calculations;

(7) Identify research & development and prepare and file forms;

(8) Coordinate tax audits (federal income tax, LCT, GST, provincial SST, and CCT), provide auditors access to data, research and provide answers to auditor's requests and negotiate beneficial resolution of proposed adjustments

(9) Prepare and file Notices of Objection and Appeal Letters and coordinate legal appeals with internal or external counsel;

(10) Devise and ensure adherence to tax policies;

(11) Conduct in-depth year end reviews of tax provisions and Terasen Gas tax returns;

(12) Write memos on tax issues and tax law changes;

(13) Interpret impact of industry issues on tax;

(14) Participate in industry group tax committees such as Canadian Gas Association and make joint submissions to government bodies on issues relevant to the industry; and

(15) Provide an overall tax leadership – plan research, provide training, file advance ruling application, co-ordinate Provincial and Federal tax.

<u>Internal Audit</u>

(1) Develop, plan and conduct audits/reviews of areas or processes of particular interest or of identified risk and prepare internal audit reports;

(2) Conduct annual risks assessment process in conjunction with the Enterprise Risk Management group;

(3) Monitor and evaluate the effectiveness and efficiency of controls throughout the year and summarize results to the Audit Committee of the Board of Directors;

(4) Ensure that the Terasen Gas Code of Conduct compliance management is effective by conducting annual compliance reviews and acting as a resource when issues arise with respect to the Code of Conduct;

(5) Provide annual reports summarizing Internal Audit activities and findings to the BCUC as well as other reports of regulatory compliance

(6) Conduct post implementation reviews of major capital projects and acquisitions and report results to the Audit Committee;

(7) Provide assistance to the external auditors in completing their external financial audits;

(8) Coordinate activities of various internal and external assurance providers to ensure proper coverage and minimize duplication of efforts; and

(9) Undertake work at the request of the BC Utilities Commission regarding the activities and operations of Terasen Gas.

<u>Risk Management and Insurance Services</u>

(1) Ensure compliance with the TSX requirements on risk management by ensuring that the Board of Directors understand the principal risks of all aspects of the business in which Terasen Gas is engaged in and ensuring that there are systems in place which effectively manage and monitor those risks with a view to the long term viability of the Terasen Gas;

(2) Arrange for coverage based on assessed potential risk of damage or loss in asset values, disruptions in operations or potential legal liabilities;

(3) Advise dollar value of coverage required, most appropriate coverage and proper services required;

(4) Provide a single insurance program to achieve economies of scales and cost reductions;

(5) Work with broker in negotiating renewals and adequacy of coverage;

(6) Ensure competitive terms and consider all available options;

(7) Establish procedures and provide assistance and guidance in the reporting, handling, compiling, negotiating and settlement of claims;

(8) Provide mechanism for appropriate and timely local resolution of third party damage claims below a given threshold, and payment of same;

(9) Conduct review of contractual agreements to protect Terasen Gas from unnecessary assumption of risks;

(10) Coordinate Risk Management's group participating in industry associations and education seminars;

(11) Establish loss control standards to help ensure consistent and high degree of loss; prevention in all operating units and minimize impact when they do occur;

(12) Ensure familiarity with policies and wordings;

(13) Encourage and establish procedures for loss control;

(14) Administer Certificates of Insurance;

(15) Preparation of management reports;

(16) Provide additional insurance for individual construction projects, as required; and

(17) Provide bonding as required.

Strategic Planning & Development

(1) Coordinate the annual update of the Corporate and Business Unit Strategic plan including Terasen Gas;

(2) Monitor the industry and business trends that influence Terasen Gas;

(3) Provide support to any major initiative which requires senior project management skills (for example, future Lease In Lease Out (LILO) transactions; and

(4) Organize management and Board strategy sessions that involve Terasen Gas.

Corporate Secretary's Office

(1) Ensure all governance activities required by external regulators and third parties are appropriately carried out, including Securities filings; and

(2) Manage the relationship with the Board of Directors, with specific accountability for the Corporate Governance Committee of the Board.

Legal Department

(1) Provide all legal services to Terasen Gas;

(2) Direct the provision and management of outside legal services to Terasen Gas;

(3) Provide management of all enterprise litigation;

(4) Provide direct, as agreed to, legal counsel on regulatory matters;

(5) Ensure legal compliance for press release, financial reports and other disclosure documents;

(6) Review, as required, legal issues that may arise including claims, actions, legal transfer, contracts, and regulatory matters; and

(7) Provide general miscellaneous legal support and advice to management.

Government Relations and Public Affairs

(1) Maintain network of contacts with elected officials and their staffs at the provincial, federal and municipal levels;

(2) Participate in industry bodies such as BC Business Council and Canadian Gas Association in determining positions to be taken on public policy issues;

(3) Provide policy advisory role on Aboriginal affairs and work on relations with Tribal Councils and Bands;

(4) Approve and review communications going to the public;

(5) Report on public opinion research;

(6) Assist in the preparation of letters to stakeholders and other communication by senior management;

(7) Oversee the development and implementation of the community investment strategy; and

(8) Oversee responses to corporate social responsibility and sustainability surveys and develop a proposal for a new sustainable development policy.

Human Resources Compensation and Planning

(1) Consult with management on the maintenance, development and governance of employee and retiree benefit programs, pension plans, employee savings plans and employee assistance programs;

(2) Provide assistance on annual wage and salary increases, providing labour market comparisons, establishing and implementing ad hoc increases for long term disability and pension recipients;

(3) Ensure that employment practices are in compliance with applicable regulations and legislation through development and administration of appropriate corporate policies and procedures;

(4) Consulting and direction on disability management guidelines and policy;

(5) Oversee the annual preparation of the executive succession plan and present the plan to the Management Resources Committee and to the Board of Directors;

(6) Corporate governance and direction regarding benefits carriers, benefits and pension consultants, financial services providers;

(7) Corporate reporting to legislative bodies, CCRA, Statistics Canada, Pension Standards, as required;

(8) Corporate direction and governance on policy development and maintenance;

(9) Provide support, training and development of staff on Corporate initiatives, systems, and policy;

(10) Provide support on Labour and Employee relations issues;

(11) Corporate governance of salary and benefits administration, including executive and management compensation; and

(12) Ensure that effective management practices are in place.

4.0 Separation of Terasen Inc.

This section of the report sets out the resources and assets currently included in the Terasen Gas cost of structure that will be transferred to the Corporate Centre by separating the Terasen Inc. functions from Terasen Gas.

4.1 Transfer of Employees, Salaries, Pensions and Expenses

With the creation of the Corporate Centre, the 47 employees on the Terasen Gas payroll who perform the head office functions noted above, and their related costs will be transferred from Terasen Gas to Terasen Inc. There will be 36 employees located at the downtown Vancouver head office location and 11 employees at the Surrey Operations Centre. The amount of salaries, pension and other expenses that previously remained and were recorded in Terasen Gas will now be incurred by Terasen Inc. The total amount of these expenses is $ 8,270,000 as set out below. With the transfer of the 47 employees to the Terasen Inc. payroll, Terasen Gas' direct labour and other expenses will be reduced by $7,321,000 and facilities and IT costs will be further reduced by $950,000 which will be recovered from Terasen Inc. Terasen Gas will then incur a corporate service charge from Terasen Inc. for the professional and management services to be provided by the Corporate Centre to Terasen Gas.

Total annual labour costs for the 47 employees (comprised mainly of professional staff), which include salaries and all benefits other than pensions and other post employment benefits ("OPEBs") being transferred from Terasen Gas amounts to $4,385,000. The pension expense and other post employment benefits related to these 47 employees has been calculated at $725,000 with the assistance of Towers Perrin for the defined benefit plans and the Terasen pension administrator for the defined contribution plans. This amount does not include the bonus portion of the pension expense which was not included in Terasen Gas' cost of service. The pension expense related to executive bonuses will be incurred by Terasen Inc. and not allocated to Terasen Gas. Other Expenses of $2,211,000 is comprised mostly of allocated shareholder expenses and allocated directors' compensation totaling $656,000 and consulting and contractor fees mainly for benefits, compensation and labour relations consultants, accounting and taxation consultants, and external legal counsel totaling $890,000. Employee expenses, other administrative expenses, overhead recoveries and the labour costs for 5 Terasen Gas union employees who will be 100% contracted to Terasen Inc. to perform external reporting, taxation and claims management services make up the remaining balance. The labour charge for the 5 Terasen Gas employees noted above is charged to Inc. in accordance with the Transfer Pricing Policy.

Terasen Inc. has contracted Terasen Gas to manage Terasen Inc.'s facilities and Information Technology infrastructure. Terasen Gas will charge Terasen Inc. $471,000 for the rent for the 24th floor of 1111 West Georgia, $264,000 for Information Technology maintenance expenses, and $108,000 for the cost of software licenses related to Terasen Inc. employees. Further, Terasen Gas will charge Terasen Inc. an additional $107,000 per annum for the use of space in the Surrey Operations Centre for eleven workstations used by the eleven Terasen Inc. employees noted above and an additional three workstations in Surrey utilized by the Corporate Centre employees. In an effort to contain costs, improve service levels to Terasen Gas and limit the space required at 1111 West Georgia, the employees from the Internal Audit, Enterprise Risk Management and Human Resources Benefits group will be located at the Surrey Operations Centre. The total Facilities and IT recoveries by Terasen Gas from Inc. will amount to $950,000.

The total transfer of budgeted direct O&M costs in Terasen Gas in 2004 is summarized as follows:

Salaries and benefits	$	4,385,000
Pensions and OPEBs		725,000
Other expenses		2,211,000
	$	7,321,000
Facilities and IT recoveries/charges		950,000
	$	8,270,000

4.2 Transfer of Assets

Assets associated with the Corporate Centre will be transferred to Terasen Inc. at their net book value which is estimated to be equivalent to fair market value. These assets are comprised mainly of leasehold improvements, computer hardware, computer software, office furniture, office equipment, and communications equipment. The net book value of these assets calculated at December 31, 2003 is estimated to be $1,465,000. A detailed listing of assets transferred is included in Attachment A to this report.

Transferring the assets to Terasen Inc. at net book value will result in a reduction in rate base. The impact on the revenue requirement is calculated as follows:

Reduction in depreciation expense	$ (305,000)
Increase in tax expense (loss of CCA)	144,000
Return on asset	(138,000)
Net impact in revenue requirement	$ (299,000)

4.3 Transfer of Liabilities

Liabilities related to the Corporate Centre employees to be transferred such as pensions, other post employment benefits and accrued vacation will also be transferred to Terasen Inc. The net pension and OPEB liability for these employees have been estimated to be $212,000 as per the Towers Perrin report calculations. The total vacation accrual for these employees is currently estimated at $323,000. These amounts will be adjusted to reflect the actual amount of the liability at December 31st, 2003 when they are transferred from Terasen Gas to Terasen Inc.

4.4 Impact of Separating Terasen Inc.

In summary, the separation of Inc. results in the following:

(a) 47 employees from the Terasen Gas payroll will be transferred to Terasen Inc.

(b) Total expenses related to these employees and their areas of service, including pensions and other post employment benefits total $7,321,000 which will be transferred to Terasen Inc.

(c) Total facilities and IT recoveries to be charged to Terasen Inc. total $950,000.

(d) Assets transferred to Terasen Inc. are estimated to be $1,465,000, and will be reflected as a reduction in rate base. The effect of the transfer of assets on the revenue requirement is $299,000.

(e) Liabilities associated with the 47 employees will also be transferred to Terasen Inc. This is estimated to be $207,000 for pensions and OPEBs and $323,000 for accrued vacation.

(f) The total amount of revenue requirement associated with the resources and assets in the separation of Terasen Inc. from Terasen Gas prior to the corporate services charge is calculated to be $8,570,000 as shown in the summary table below:

Transfer of 47 employees expenses and related costs	$ 7,321,000
Facilities and IT recoveries	950,000
Transfer of assets	299,000
	$ 8,570,000

5.0 Cost Allocation Study of Corporate Centre Costs

In order to ensure the reasonableness of the allocation of Corporate Centre costs to Terasen Gas, a cost allocation study was undertaken.

Deloitte & Touche LLP were engaged to assist in developing an approach to allocate shared corporate services costs from Terasen Inc. to its regulated and non-regulated subsidiaries. A copy of this report is attached in Attachment B. Based on the recommendations in that report, a combination of methods was utilized to determine the allocation of the shared corporate service costs to Terasen Gas. These are summarized as follows:

(1) Direct costs represent specific time and services provided by individuals to support activities of Terasen Gas. Employees will charge specific time to charge orders of Terasen Gas. Accordingly, time sheet specific direct allocations will account for a significant amount of the budgeted charges to Terasen Gas.

(2) Indirect costs which cannot be directly attributable will be allocated using the formula approach based upon the Massachusetts formula as discussed in the Deloitte & Touche report.

(3) Corporate sustaining costs which refer to activities undertaken to support the organization as a whole and benefit all the business units will also be allocated using the Massachusetts formula approach.

(4) Costs that do not impact Terasen Gas, such as time and resources spent on major projects such as acquisitions, or on non-Terasen Gas business, will be fully and directly allocated to Terasen Inc. or one of its subsidiaries. This includes the bonus component of the pension expense which is fully allocated to Terasen Inc.

The formula approach refers to the method of charging indirect and corporate sustaining costs to a common pool and then allocating them to the subsidiaries using a mathematical formula. The Massachusetts Formula is in extensive use in industry and is composed of the arithmetical average of (1) operating revenue, (2) payroll, and (3) average net book value of tangible capital assets plus inventories. The use of these factors represents the total activity of all business segments as a means to allocate costs that cannot be directly assigned. The Commission's Decision allowed a maximum of 50% of common costs to be allocated to Terasen Gas. Using the Massachusetts Formula, Terasen Gas would be allocated 53% of the common costs of the Corporate Centre. The Nebraska formula method was also considered, but this formula only utilized two of the above parameters (it excludes operating revenue) and its use would have resulted in a slightly greater charge to Terasen Gas as it calculates a 54.1% allocation to Terasen Gas.

The table below shows a summary of the results based on 2004 estimates:

			Terasen Gas		Inc. and subs		Total
A	Operating Revenues	$	500,000	$	480,122	$	980,122
			51.0%		49.0%		100.0%
B	Payroll	$	66,226	$	64,048	$	130,274
			50.8%		49.2%		100.0%
C	Avg. NBV of tangible capital assets + inventories	$	2,400,000	$	1,788,564	$	4,188,564
			57.3%		42.7%		100.0%
	Massachussets Method - avg of A,B,C						
A	Operating Revenues		51.0%		49.0%		100.0%
B	Payroll		50.8%		49.2%		100.0%
C	Avg. NBV of tangible capital assets + inventories		57.3%		42.7%		100.0%
			53.0%		**47.0%**		**100.0%**
	Kansas/Nebraska Formula - avg of B,C						
B	Payroll		50.8%		49.2%		100.0%
C	Avg. NBV of tangible capital assets + inventories		57.3%		42.7%		100.0%
			54.1%		**45.9%**		**100.0%**

Using both the direct and formula based cost allocation methodologies, Terasen Gas would be charged $9,158,000 for the services to be provided by the Corporate Centre group. This is comprised of two components: $5,820,000 of direct charges for labour and overheads for work performed directly on Terasen Gas and an allocated amount of $3,338,000 as its share of the common costs incurred by Terasen Inc. based on the Massachusetts formula. This amounts to 52.1% of the total Corporate Centre costs.

However, as previously stated during the current PBR settlement, Terasen Gas' cost of service will not be increased due to establishment of a Corporate Centre. The current amount embedded in Terasen Gas' cost of service for all the corporate centre services is $8,570,000 as noted in Section 4.4. Therefore, the management fee for the professional services provided by Terasen Inc. to Terasen Gas will be set at $8,570,000 which represents the amount currently included in the Terasen Gas cost of service for these services. This results in an allocation of 48.8% of the total Corporate Centre costs to Terasen Gas.

The table below summarizes our results:

	Results from Allocation Study			Proposed Management Fee		
		Charges to Terasen Gas	% of Inc total charges		Charges to Terasen Gas	% of Inc total charges
Direct Charges	$	5,820	51.6%	$	5,446	48.3%
Common Costs		3,339	53.0%		3,124	49.6%
Total Charges	$	9,158	52.1%	$	8,570	48.8%

6.0 The Corporate Services Fee

Based on the cost allocation study which uses a combination of direct charges and formula based allocation of common costs, the corporate services fee from Terasen Inc. to Terasen Gas would be set at $9,158,000. However, as noted in Section 1.2 of the report, the total charge for services transferred from Terasen Gas to Terasen Inc. will be charged back at the same level of costs as approved in the 2003 Revenue Requirements Decision, adjusted for inflation, growth and productivity in accordance with the PBR model. For 2004, this amount was determined to be $8,570,000 as noted in Section 4.4. Accordingly, the amount to be charged to Terasen Gas in 2004 for the corporate services provided is $8,570,000.

7.0 Corporate Centre Services - Business Case

This section of the report addresses the requirements expressed in the Decision at page 52 that "BC Gas Utility is to identify any services that it has contracted for from BC Gas Inc. in the next revenue requirements filing and should include information on the cost of service and business case supporting the contract." The alternative means available to provide such services through in-sourcing at Terasen Gas or by contracting such services externally are discussed below. The comparison establishes the business case to Terasen Gas for the provision of services from Terasen Inc. relative to Terasen Gas' other alternatives.

In order to assess the value of the Corporate Services arrangement to Terasen Gas, the corporate services fee was compared to an estimate of the cost of in-sourcing the activities within Terasen Gas or outsourcing them to third parties. Because many of the services relate to governance, policy or strategy and reflect the economies of scale from a corporate centre approach, it is more reasonable to look at the in-sourcing alternative (or replication of such services on a stand alone basis) rather than outsourcing even where estimates of market costs for resources of a similar level (i.e. from professional services providers) can be obtained.

The focus of this analysis was on whether the bundle of services, contained in the proposed Corporate Services contract, is cost effective for Terasen Gas and its customers. The cost of the stand-alone alternative was built up in stages beginning with labour requirements. Each service was reviewed for the required incremental staffing complement needed to meet the service demand. For some services it was possible to reduce the level of professional expertise as a way of minimizing labour costs and substitute contract services from professional services providers. However, insourcing would result in the loss of scale economies.

The total number of Corporate Centre related employees amounts to 52 full time equivalents (FTEs). In determining the directly attributable costs time sheet estimates were utilized and based on the 2003 planned chargeable hours relating to Terasen Gas by individual. A total 32.9 FTEs were included in these estimates. A review of the number of employees that would be required to replicate the services of the Corporate Centre within Terasen Gas was completed on a functional area basis.

The direct costs associated with employees required on a stand alone basis were estimated based on the existing compensation and benefits levels of the incumbents in these roles. Standard estimates were made for personnel supporting costs such as IT, telecom, facilities, fees and dues, office supplies, employee expenses, pensions and OPEB costs, etc. These costs would be expected to be very similar to those incurred in the corporate centre on a per employee basis.

Consulting and contractor costs were also estimated on a stand alone basis and would be generally consistent with costs incurred by the Corporate Centre except to the extent that some groups (e.g. Taxation) would be expected to contract for certain expertise rather than in-source it whereas the corporate centre would actually have a resource on staff.

A summary of the review conducted by functional area is provided below.

CEO

The Chief Executive Officer's functions are currently not performed within Terasen Gas by the President which fulfills the role of a chief operating officer which is a full time role. Historically, when the Terasen group of companies was smaller, the utility executive group was larger with a combined President/CEO role and a Senior Vice President of Operations who in turn had a number of operating vice presidents reporting to him. As the size of the corporate group expanded, Terasen Gas streamlined its executive and the duties of the President/CEO and Senior VP of Operations position were redistributed resulting in the current structure and division of responsibilities.

If the duties of the chief executive were moved back into Terasen Gas on a stand alone basis, the President would be unable to absorb them. It is unlikely that two separate positions for CEO and President would be maintained, but an additional senior executive position would be required in order to reabsorb and redistribute the responsibilities performed respectively by the CEO, the CFO and the Terasen Gas President roles in the current organization structure (see further discussion under CFO below). This would likely result in expanding the President's current responsibilities.

The requirement to take on greater responsibility in a stand alone Terasen Gas by the President/CEO would result in off loading of responsibilities onto a newly created senior executive position and the existing Terasen Gas executive. The CEO's area currently includes 3 FTEs including the CEO and two support staff of which the directly attributable time amounts to 1.4 FTEs (0.3 of which relates to the CEO). It was estimated that Terasen Gas would require approximately one FTE of time associated with the additional support staff relating to the expanded executive duties. The analysis also took into consideration that compensation adjustments and costs associated with an additional executive resource would be required under the stand alone structure

CFO & External Reporting

The corporate centre will have six FTEs providing services to the Terasen Group of companies of which 3.3 FTEs can be directly attributed to Terasen Gas' requirements. It is estimated that on a stand alone basis one manager and two accounting analysts would be required. The duties performed by the current CFO on behalf of Terasen Gas would still be required on a stand alone basis and could not be absorbed by the VP Finance & Regulatory Affairs. While this would not be expected to result in the addition of another VP level role, it would necessitate a restructuring of the existing position and responsibilities and result in the requirement for one additional senior resource beyond that in the existing structure.

Corporate Communications and Government Affairs

The corporate centre will have two staff of which 1.3 FTEs can be directly attributed to Terasen Gas. It is estimated that on a stand alone basis two employees would be required. Consulting costs would be similar to those currently allocated.

Corporate Secretary

This group consists of 3 individuals including the General Counsel. The majority of their time is attributable to the utility or 2.4 FTEs. However corporate centre provides significant economies of scale in this area as the costs of the board, shareholder, annual report and auditing expenses are allocated from this area. On a stand alone basis, Terasen Gas would have to bare virtually all these cost versus sharing them amongst the Terasen group of companies.

Risk Management and Insurance Services

This group includes four employees, all of whom would have to be replicated within the utility on a stand alone basis or certain expertise contracted in at a higher cost. Currently only 2.2 FTEs are directly attributable to Terasen Gas.

Corporate Financial Analysis and Capital Management

This group includes two senior financial analysts and a director of which approximately 1.6 FTEs are attributable to Terasen Gas requirements. On a stand alone basis it is estimated that Terasen Gas would have to replace two of these individuals to continue to meet Terasen Gas' needs.

Internal Audit

The internal audit group is resourced with six staff including a director of internal audit, four internal auditors and an administrative assistant for the group. Approximately 4.1 FTEs are attributable to Terasen Gas related audit services. Although some of the skill sets are transferable, it would not be shared with the finance group in order to maintain their independence. It is estimated that Terasen Gas would need 5 employees in a stand alone internal audit group.

Human Resources

The corporate group consists of seven individuals to manage pension, benefit and compensation programs of which 5.2 FTEs are directly attributable to the requirements of the utility. Due to the size of the organization and the requirements of the collective bargaining related processes it is estimated that six full time employees would be required in the utility on a stand alone basis including a senior executive position. The stand alone costs include consulting/contractor related costs that are consistent with those costs incurred on behalf of the utility in the corporate centre group.

Legal

The corporate group has seven staff including four lawyers and 3 legal secretaries. The majority of the time spent by the group is directly attributable to the requirements of the utility (5.8 FTEs). In addition, external legal support would continue to be required by Terasen Gas for specialized services. It is estimated that Terasen Gas would reduce the current staff levels and only require to 3 lawyers and two support staff on a stand alone basis supplemented by additional contracted legal services for more complex requirements

Strategic Planning and Development

This group consists of 3 employees including a senior executive, a senior financial professional and an administrative assistant. Currently approximately 0.8 FTEs is directly attributable to utility requirements. On a stand alone basis it is estimated that one employee would be required in the utility to provide these services supplemented by external consulting support.

Taxation

The corporate centre has 5 FTEs including four tax professionals with increasing levels of expertise as well as an administrative assistant. Currently approximately 3.0 FTEs of time are attributable to Terasen as requirements. On a stand alone basis Terasen Gas would still require 3 staff supplemented with expert tax advice from a professional services firm.

Treasury and Cash Management

The treasury group consists of 3 individuals, the assistant treasurer and two analysts of which approximately 2.0 FTEs is attributable to utility requirements. On a stand alone basis it is estimated that two employees could satisfy the requirements. Contract and consulting costs would be consistent with those currently shared amongst the group of companies.

As indicated above, while staff related costs could be expected to be consistent with those incurred in the Corporate Centre, the total number of FTEs Terasen Gas would require is greater than the number provided through the Corporate Centre in most areas. This is driven by the requirement to hire full time positions as opposed to utilizing a shared resource. This represents an increase of more than 6 FTEs net to replicate corporate services on a stand-alone basis. In addition, certain skill requirements would have to be supplemented with contracted services from professional services firms.

It is estimated that the cost to replicate the Corporate Centre services within Terasen Gas is approximately $9,500,000 on an annual basis. This cost estimate does not consider the start-up costs required to establish a stand-alone alternative, such as recruitment costs and learning curve considerations, or the incremental contract management resources needed to manage corporate services that would be outsourced to third parties.

In addition, Terasen Gas currently benefits from economies of scale resulting from participating in joint insurance and employee benefit programs as part of a corporate group. The cost of these programs would be greater if these were to be sourced for Terasen Gas on a stand alone basis rather than as corporate programs under a Terasen Inc. umbrella because fixed administrative costs would not be shared over as large a number of employees and risk diversification/buying power would not be as great driving higher insurance related costs. A more detailed assessment would be required to quantify these additional cost impacts but they would be additive to the already more costly stand alone alternative.

Based on the discussion above, the $9,500,000 cost estimate for the stand-alone alternative is approximately $900,000 or 11% higher than the planned Corporate Service fee from Terasen Inc. for a similar suite of services. Since the planned management fee is well below both the estimated cost of the stand alone alternative and the amount that would be determined utilizing direct costing and the industry accepted allocation methods (Massachusetts and Nebraska methods), Terasen Gas believes it represents good value to the Terasen Gas and its customers. Moreover, because the planned fee is consistent with the cost of service built into rates for these activities and limited future increases based on the PBR formula, the fee incorporates productivity benefits.

8.0 Corporate Services Agreement

Terasen Gas will enter into an annual Corporate Centre Services agreement with Terasen Inc. for the services it requires and will receive from Terasen Inc. The services will be paid for through an annual corporate services fee. The contract will be effective January 1, 2004.

The Corporate Services Agreement (CSA) will describe the services relating to the provision of management and professional services to be provided by Terasen Inc. to Terasen Gas as set out in this report.

To satisfy the dual objectives of simplicity and fairness, the contract will represent a maximum charge that is consistent with the following:

(1) The total charge for 2004 will be $8,570,000, which is the amount actually incurred in 2003 adjusted for inflation, growth and productivity per the PBR formula. This ensures that the Terasen Gas revenue requirement remains unchanged through the separation of these functions..

(2) The contract is of take or pay nature. This is consistent with the treatment of the current and ongoing Continuing Services contracts between Terasen Gas and its affiliates. These contracts cover services provided by Terasen Gas employees to the non-regulated affiliated companies. However, it caps the level of cost for the prescribed service under the CSA in the event that the actual time spent exceeds the estimates used in the underlying costing assumptions. This differs from the continuing services contracts, where Terasen Gas recovers the costs of incremental service delivery beyond that contracted for. The fixed fee arrangement is of value to Terasen Gas in that it provides certainty of cost effective corporate services while providing protection to the provider of such services since Terasen Inc. must maintain personnel and incur the related cost to meet the contracted level of service.

(3) The charges must be in accordance with the services agreed to in the contract. Any services not previously contemplated should be provided in a separate supplement to the agreement.

(4) If any services are not provided by Inc. in accordance with the agreement, then appropriate credit should be given to Terasen Gas for such deficiency of services based upon a reasonable estimate of allocated cost.

The pricing terms of the Corporate Services Agreement are based on an annual corporate services fee. The fee is subject to review each year and subject to adjustments following the PBR formula.

The term of the agreement is for one year, subject to annual renewals. The annual corporate services fee will be subject to renegotiation for any change in services. To allow for increases or decreases in associated staffing levels, notification for termination of or changes to the contract or service requirements must be given with six months’ written notice.

9.0 Continuing Services

Terasen Gas will continue to provide certain support services to Terasen Inc. in accordance with the Code of Conduct and Transfer Pricing Policy. Services to be provided by Terasen Gas include payroll processing, facilities management, information technology and enterprise resource planning, web site administration, mailroom support, and accounts payable. Total charges to be recovered by Terasen Gas from Terasen Inc. for 2004 are estimated at $300,000.

Terasen Gas will also charge Terasen Inc. for the 5 union employees that will be fully contracted out to Terasen Inc. in accordance with the Transfer Pricing Policy.

10.0 Summary

This report sets out a plan for separating Terasen Inc. resources and responsibilities from Terasen Gas by establishing a Corporate Centre for the provision of specified corporate services to Terasen Gas and other Terasen Inc. subsidiaries. The Corporate Centre maintains the economies of scale presently being achieved through the centralization of these services at Terasen Gas and provides greater transparency in separating the operating costs of the Corporate Centre from the Terasen group of companies including Terasen Gas.

The report indicates which assets and resources will be transferred from Terasen Gas to the Corporate Centre as well as certain services that will continue to be provided to Terasen Inc. by Terasen Gas. In addition, the report details the specific corporate services to be provided from the Corporate Centre to Terasen Gas by functional area.

The proposed Corporate Services fee that will be specified in the Corporate Services agreement will be neutral in terms of revenue requirements impact based on the allowed cost of service resulting from the 2003 Revenue Requirement proceeding and as adjusted according to the PBR formula. For 2004, this amount has been determined to be $8,570,000.

An allocation of corporate centre costs among the various subsidiaries based on generally accepted costing methodologies is presented in the report. This allocation indicates that $9,158,000 of costs can be attributed to Terasen Gas. This analysis supports a Corporate Services fee higher than the $8,570,000 fee recommended in the report and as reflected in the current costs allowed in the Terasen Gas revenue requirement. This reinforces the reasonableness of the existing allocation from a Terasen Gas perspective. In order to further validate the Corporate Services fee, a business case comparison was performed comparing the Corporate Services fee to the cost of replicating these services on a stand-alone basis. This analysis shows that the cost would be $9,500,000 if Terasen Gas were to provide these services on a stand-alone basis. This also supports the conclusion that the Corporate Services fee is reasonable and provides value to Terasen Gas and its customers.

The Corporate Centre and the associated Corporate Services agreements will be put in place January 1, 2004.

Attachment A

Detailed Listing of Assets Transferred

Terasen Gas Inc.
Calculation of Assets held at Head Office for Terasen Inc. at December 31, 2003

Quantity	Description	Est. Avg.Age	Estimated value per unit	Total Cost	Accum. Dep'n	NBV	Annual Dep'n
	Leasehold Improvements						
1	Leasehold improvements	0	660,100.00	660,100.00	0.00	660,100.00	72,011.00
	Computer Hardware						
26	Computers (desktop)	3	4,000.00	104,000.00	62,400.00	41,600.00	20,800.00
40	Computers (laptop)	3	5,000.00	200,000.00	120,000.00	80,000.00	40,000.00
4	Servers	3	13,500.00	54,000.00	32,400.00	21,600.00	10,800.00
			22,500.00	358,000.00	214,800.00	143,200.00	71,600.00
	Computer Software						
66	Software	3	1,000.00	66,000.00	24,750.00	41,250.00	8,250.00
	Office Furniture						
5	Executive Offices	10	25,000.00	125,000.00	62,500.00	62,500.00	6,250.00
4	Medium Offices	10	10,000.00	40,000.00	20,000.00	20,000.00	2,000.00
14	Small Offices	10	7,000.00	98,000.00	49,000.00	49,000.00	4,900.00
28	Workstations (desk, chair, file cabinet)	5	6,000.00	168,000.00	42,000.00	126,000.00	8,400.00
62	File Cabinets	5	1,400.00	86,800.00	21,700.00	65,100.00	4,340.00
1	Meeting Room -BC	10	50,000.00	50,000.00	25,000.00	25,000.00	2,500.00
1	Meeting Room - Inland	10	15,000.00	15,000.00	7,500.00	7,500.00	750.00
1	Meeting Room - Seymour	10	10,000.00	10,000.00	5,000.00	5,000.00	500.00
1	Other Meeting Rooms	10	5,000.00	5,000.00	2,500.00	2,500.00	250.00
56	Meeting Room Chairs	10	1,100.00	61,600.00	30,800.00	30,800.00	3,080.00
15	Whiteboards	5	1,500.00	22,500.00	5,625.00	16,875.00	1,125.00
1	Lunch Room	5	1,400.00	1,400.00	350.00	1,050.00	70.00
1	Reception Desk	5	20,000.00	20,000.00	5,000.00	15,000.00	1,000.00
8	Reception Area Chairs	5	3,000.00	24,000.00	6,000.00	18,000.00	1,200.00
6	Coffee tables	5	1,200.00	7,200.00	1,800.00	5,400.00	360.00
2	AV Cart	5	550.00	1,100.00	275.00	825.00	55.00
1	Mail Slots	5	300.00	300.00	75.00	225.00	15.00
			158,450.00	735,900.00	285,125.00	450,775.00	36,795.00
	Office Equipment						
25	Printer	3	4,000.00	100,000.00	15,000.00	85,000.00	5,000.00
4	Fax Machine	5	2,000.00	8,000.00	2,000.00	6,000.00	400.00
1	AV Equipment (BC Room)	5	10,000.00	10,000.00	2,500.00	7,500.00	500.00
4	Photocopier	5	15,000.00	60,000.00	15,000.00	45,000.00	3,000.00
2	Scanners	3	800.00	1,600.00	240.00	1,360.00	80.00
			31,800.00	179,600.00	34,740.00	144,860.00	8,980.00
	Communications Equipment						
55	Standard Phone	10	800.00	44,000.00	22,000.00	22,000.00	2,200.00
1	Switchboard	10	5,000.00	5,000.00	2,500.00	2,500.00	250.00
			5,800.00	49,000.00	24,500.00	24,500.00	2,450.00
	Total of Purchased Assets			**2,048,600.00**	**583,915.00**	**1,464,685.00**	**200,086.00**

Summary

Class	Description	Depn Rate	Cost	Accm Depn	NBV	Annual Dep'n
48230	Leased Premises BC Gas Centre	10.00%	660,100.00	0.00	660,100.00	72,011.00
48310	Computer Hardware	20.00%	358,000.00	(214,800.00)	143,200.00	71,600.00
48320	Computer Software	12.50%	66,000.00	(24,750.00)	41,250.00	8,250.00
48330	Office Equipment	5.00%	179,600.00	(34,740.00)	144,860.00	8,980.00
48340	Office Furniture	5.00%	735,900.00	(285,125.00)	450,775.00	36,795.00
48810	Communications Telephone Equipment	5.00%	49,000.00	(24,500.00)	24,500.00	2,450.00
	Total		2,048,600.00	(583,915.00)	1,464,685.00	200,086.00

Attachment B

Deloitte & Touche Report

Deloitte & Touche

Terasen Inc.

Regulatory Cost Allocation Study

Final Report

October 29, 2003

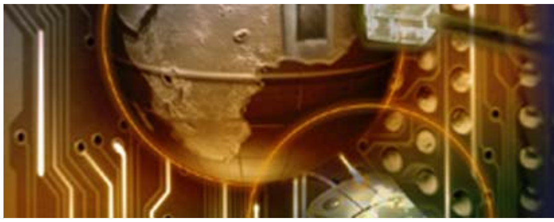

Table of Contents

1 Executive Summary

Deloitte & Touche LLP (D&T) was engaged to assist Terasen Inc. in developing an approach to allocate corporate service costs from the holdings company (Terasen Inc.) to the Regulated and Non-Regulated Businesses. The total cost for these corporate services is between $15 million and $20 million.

I. Determining the Allocation Method

Prior to the implementation of any cost allocation methodology, it is first necessary to define objectives against which to evaluate each method. There are four objectives applicable to cost allocation in a regulatory environment. The approach should a) demonstrate a causal link between activities undertaken and the “cost object” that is causing that activity to take place; b) be both supportable and reasonable; c) be efficient to administer; and d) be flexible and responsive to organizational and environmental change.

The next steps are to:

- Identify and understand the various costs which must be allocated;
- Determine how these costs should be measured; and
- Determine how the costs should be charged.

Determining costs be allocated - Costs can be grouped into three major categories: **direct, indirect** and **corporate** sustaining. These costs have a hierarchy of linkage to the activity, which is causing them to be incurred. The decision whether or not to allocate them becomes less clear as they become further removed from the delivery of products and services.

Measurement of costs - The most common units of measure include **incremental / marginal cost, fully embedded cost, and market cost.** There are several influencing factors in determining the best unit of measure such as; the primary reason for the activity to be conducted, and whether an external market for the service exists whereby the company could be purchasing the same or similar service from a third party. Answers to these and other influencing questions may affect the measure to be used.

Method of charging - There are three principal approaches used to allocate costs in the regulatory environment. These are the **formula, time sheet based and the volumetric drivers approaches**. These approaches aim to drive costs to business units in relation to consumption. The formula based method uses broad measures such as revenue or salaries as a proxy for how much consumption of a given activity may take place. The time sheet approach is very specific for the labour element of the costs to be allocated and the “volumetric driver” approach breaks costs down by activity performed and attaches a specific driver to each activity commensurate with how that activity is consumed. For instance, payroll processing may be allocated based on the number of payroll cheques produced and Information Technology costs may be allocated based on the number of computers in use.

II. Recommendation

In reviewing each cost allocation method against the defined objectives and taking into account the characteristics of the cost categories, it appears that the most appropriate solution is one that combines allocation methods. These results are summarized in the table below.

COST TYPE	UNIT OF MEASURE	ALLOCATION METHOD
DIRECT COSTS		
Clearly Attributable	▪ Fully embedded	▪ Timesheet
Repetitive & Consistent	▪ Fully embedded	▪ Volumetric Driver
INDIRECT COSTS	▪ Fully embedded	▪ Formula
CORPORATE SUSTAINING COSTS	▪ Fully embedded	▪ Formula

2 Introduction / Nature of the Engagement

Terasen Inc. is a leading energy distribution and transportation company as well as a provider of services related to energy and water distribution that are both regulatory and non-regulatory in nature.

Deloitte & Touche LLP (D&T) was engaged to assist the company in developing an approach to allocate costs from the holdings company (Terasen Inc.) to the Regulated and Non-Regulated Businesses. The total cost for these corporate services is between$15 million and $20 million.

The intent of this report is not to provide specific recommendations around which costs should be included as part of corporate costs and the allocation method, which should be used, but rather, it provides a framework that can be incorporated into Terasen's internal decision-making processes for cost allocation.

3 Determining the Method of Allocation

In determining the best method of allocating common costs, it is first necessary to determine objectives against which to evaluate each method. The next step is to identify and understand the various costs, which should be considered for allocation. These costs then need to be measured and allocated. Each of these elements is discussed in the sections, which follow.

I. Objectives of Cost Allocation Principles

In applying a costing methodology, a variety of objectives need to be considered. There are four objectives applicable to costing approaches in a regulatory environment:

- The approach should demonstrate a causal link between activities and the "cost object" that is causing that activity to take place;
- The approach must be both supportable and reasonable;
- The approach must be efficient to administer; and
- The approach must be flexible and responsive to organizational and environmental change.

Causal Link between Activities and Cost Objects

The underlying principle for the allocation of costs must be based on what is causing that cost to be incurred. The driver of that cost can be viewed in many different ways: head count, number of customers, volume of vouchers or even square footage. As such, the allocation of costs to cost objects based on their linkage should be performed at the activity level through the use of appropriate cost-drivers.

Supportable and Reasonable

In addition to establishing a link between activities and products or services, the approach of cost allocation must be both supportable and reasonable. This will provide a framework that can trace a resource (labour, expenses, occupancy, etc.) from its root to the final product or service cost. Reasonability is achieved when the approach a) produces results that are consistent with expectations, and b) demonstrates a clear understanding of the products and services each business unit provides and what products and services (if any) they support in any other areas of the organization.

Ease of Administration

Cost allocation models can become overly complex and extremely time consuming and costly to administer. A properly developed cost allocation approach and resulting model should not become a burden on the organization, but rather should involve minimal time to update and administer.

Flexible and Responsive

The need for a cost allocation approach that is flexible and responsive to organizational and environmental change is important. Without flexibility and responsiveness, the methodology will continually have to be modified and updates to the modeling tool will result. This becomes inefficient and brings into question the completeness and appropriateness of the approach if it does not have the ability to apply to changing circumstance.

II. Identification of Cost Objects

Cost objects can be defined as any activities for which a separate measurement of cost is desired. Once the pool of costs has been identified, they then need to be reviewed by major cost or activity type. Cost types can be broken down into three major groupings. There is a hierarchy associated with these costs. The decision whether or not to allocate the cost type becomes less clear as they become further removed from the delivery of the product. The three major cost categories are as follows:

- Direct Costs
- Indirect Costs
- Corporate Sustaining Costs

Direct Costs

Direct costs are those that can be clearly attributed to one product / service; or one business segment; or one specific operation in the process. In addition, direct costs are often repetitive and consistent over time in relation to the level of effort per unit of service provided.

Some examples of direct costs include:

CLEARLY ATTRIBUTED	REPETITIVE & CONSISTENT OVER TIME
▪ Legal services	▪ Accounts Payable
▪ Financial Analysis	▪ Payroll
▪ Taxation	▪ Call Centre

Indirect Costs

Indirect costs can be defined as those costs, which are further, removed from and cannot be directly attributed to specific products, organizational units or activities, but may support activities associated with those products and / or organizational units. Examples of indirect costs are administrative costs, rent, and information technology. These costs, while they do not demonstrate the strongest causal link to a specific product or process, directly support the direct costs described above and often, the direct cost activities could not take place without these indirect costs being incurred.

Corporate Sustaining Costs

Corporate sustaining costs refer to activities undertaken to support the organization as a whole and benefits all business units. Examples of corporate sustaining costs include investor relations, director fees, internal audit, executive salaries and audit fees.

Inherent in its definition, direct costs must demonstrate a clear link between cost and a product / service, business segment or process. This being the case, the decision to allocate direct costs is clear. The question then becomes which indirect and corporate sustaining costs should be allocated. In determining this, it is necessary to understand whether the indirect or corporate sustaining costs support or aid in the delivery of product/service or whether the costs are incurred as a result of doing business.

III. Measurement of Cost

There are many different ways to measure effort. The most common units of measure include Incremental / Marginal Cost, Fully Embedded Cost, and Market Based Cost.

Incremental or marginal cost is essentially variable cost. It is the additional cost involved in taking a particular course of action, such as increasing production levels.

Fully Embedded Costs layer semi-variable and fixed cost elements onto the marginal or variable costs.

Market Based Cost is the cost that would be incurred if a third party were to provide the service i.e. outsourced payroll processing.

There are several influencing factors in determining which unit of measure to use. Some of these factors include:

I. the primary reason for the activity to be conducted; and

II. whether an external market for the service exists whereby the company could be purchasing the same or similar service from a third party.

Regardless of these influencing factors, regulators generally maintain the position that the underlying principle to be used in determining unit of measure is that the ratepayer not subsidize the activities of non-regulated businesses.

IV. Cost Allocation Methods

There are three principal approaches that can be used to allocate costs. These are the ***Formula, Time Based*** and ***the Volumetric Drivers Approaches***. These three approaches are all methods to drive costs to business units in relation to consumption. As such, each uses a form of **cost driver** as its basis. Each of these approaches is discussed below, focusing in greater detail on their objectives, advantages, and descriptions of their application.

1. Formula Approach

The formula approach was developed in order to provide a means of allocating common costs (i.e. those that cannot be directly charged). These costs are grouped into one cost pool and are charged to the various business segments on the basis of a mathematical formula. One such formula, the **Massachusetts Formula**, is in extensive use in the industry. This formula allocates costs based on the arithmetical average of: (1) operating revenue, (2) payroll, and (3) average net book value of tangible capital assets plus inventories. The rationale for the inclusion of revenues, payroll, and capital assets in the calculation, is that collectively, these factors represent the total activity of all business segments. In addition, the use of these factors takes into account different business environments i.e. capital intensive and labour intensive businesses. The Massachusetts Formula has been modified by several utilities in the United States resulting in the **Kansas/Nebraska Formula.** This formula is identical to the Massachusetts Formula, except that it excludes operating revenue in the calculation of the average.

Benefits and Disadvantages

The most significant advantage of the formula approach is that it is easy to implement and administer the allocation of common costs. All that is required is that the pool of common costs be kept to a minimum. Furthermore, the use of a formula removes the use of judgment and thus eliminates any subjectivity, which might enter into cost allocation decisions.

The most significant drawback of the formula approach is that it is mathematical. Mathematical approaches do not take into account special business circumstances when allocating common costs. There may be specific circumstances where a different factor or factor weighting (i.e. other than proportionate) is justified thereby generating drastically different results. A second drawback is the formula approach does not allow corporations to recognize that certain business activities, even if not directly attributable to a business segment, may be viewed as supporting one business segment or another to a degree not properly reflected by a mathematical formula. This situation is fairly common and is one of the reasons why other methodologies (i.e. time sheets and volumetric drivers) have been developed. Finally, the formula approach suffers from the fact that it cannot be readily changed to suit changing circumstances.

2. Time Sheet Approach

The time sheet approach typically only applies to the labour component of cost and requires the following components:

- a listing of business segments which will be allocated common costs;
- periodic (e.g. weekly, monthly) completion of time sheets by employee or department; and
- accumulation of time sheets by the accounting department for the calculation of period charges to each segment.

Some time sheet based systems include budgeted allocations allowing for comparisons to actual time spent performing activities for a business unit. In addition, some utilities use a reporting mechanism that provides employees with information about cumulative reported and/or budgeted time by segment, allowing for reasonability checks and an opportunity to improve future time reporting.

The principal objective of the time sheet approach is to use employee input in the cost allocation process. In this way, an audit trail is also developed to provide the "how and why" behind cost allocations.

Benefits and Disadvantages

The primary benefit of the time sheet approach is the increased accuracy of cost allocation. Having employees track time spent on major activities (e.g. legal or tax services) for various business segments, demonstrates a clear linkage between activity and cost. A second advantage to this approach is that it allows the organization the flexibility to allocate costs on a budgeted or real time basis (e.g. weekly).

Time sheet based allocation systems do have significant drawbacks. Most time sheet systems require a feedback loop in order to provide the benefits of recording and maintaining detailed time reporting information. Often, comprehensive feedback reporting systems are costly to implement, and perhaps even more costly to maintain. Time sheet approaches rely on the employee to track time and expenses and enter them on a regularly basis allowing for clerical error. Organizations must then review and verify input, and generate reports. This often requires extensive payroll, data input, information systems and other support staff involvement.

3. Volumetric Driver Approach

The volumetric driver approach operates on the principle of identifying a link between specific types of expenses or activities and business segments. The methodology requires that costs similar in behaviour are grouped and that volume drivers be defined. The costs within a cost pool can then be charged to business segments based on a volumetric driver. This approach is best suited to service organizations which process standard transactions as opposed to service organizations, which primarily provide labour, based services. Cost pools and drivers must be established with two thoughts in mind: the driver volumes must reflect the effort spent by staff on specific activities; and the use of drivers must fairly attribute costs to business segments. Costs not consumed in a consistent manner do not lend themselves to this approach.

Examples of Volumetric Drivers

The following table illustrates examples of selected cost centres and lists potential drivers for all or part of each cost centre.

COST CENTRE	TYPICAL ACTIVITIES OR EXPENSES	POTENTIAL COST DRIVERS
Accounting department	▪ Accounts Payable	▪ Estimated number of accounts payable vouchers
Customer service	▪ Billing	▪ Number of customers
Accounting department	▪ Payroll	▪ Head count
Accounting department	▪ Processing journal vouchers	▪ Number of journal vouchers
Administration	▪ Property maintenance	▪ Head count
Information systems	▪ Systems Development	▪ Allocated to departments based on application and then allocated based on the composite ratio for that department

Benefits and Disadvantages

The key benefit of the volumetric driver approach is that it is entirely objective. Once in place, the volumetric driver calculates the proportion of each department's cost that is attributable to each business segment based strictly upon the transaction volumes of the pre-set drivers.

The most significant drawback of this approach is the effort required to set it up. Cost drivers must be defined and cost pools created. However, once these elements are defined automated systems can be used to capture this information thus reducing effort required for ongoing maintenance. Finally, the volumetric driver approach must be monitored on a periodic basis in order to ensure that the volumetric drivers themselves remain current and reasonable. This can be accomplished through discussions with department managers to ensure that individual drivers adequately measure costs.

4 Evaluation & Recommendation

In reviewing each cost allocation method against the objectives initially defined (see table below), it appears that the volumetric driver approach emerges as a preferred approach.

		COST ALLOCATION METHOD		
		FORMULA BASED	TIME SHEET	VOLUMETRIC DRIVER
OBJECTIVES	Causal link between activities and cost objects		✓	✓
	Supportable and reasonable	✓	✓	✓
	Ease of administration	✓		✓
	Flexible and responsive			✓

Evaluating the allocation methods without taking into account the various characteristics of the cost categories would not be complete. When reviewing the methods of allocation against each of the cost pools, it appears that a combination of allocation methods is a more appropriate solution. These results are summarized in the table below and then discussed in further detail.

		COST ALLOCATION METHOD		
		FORMULA BASED	TIME SHEET	VOLUMETRIC DRIVER
COST CATEGORIES	Direct Costs		✓	✓
	Indirect Costs	✓		
	Corporate Sustaining Costs	✓		

Direct Costs

Direct costs can be further segregated into those that can be clearly attributed and those that are repetitive and consistent over time as to level of effort per unit of service provided. Those labour costs that can be clearly attributed to a specific activity, process or business segment are usually measured using the marginal or fully embedded costing approach. This cost type lends itself to **time reporting** as the best method of cost allocation. As well, this method provides a strong level of detail and support and provides the strongest causal link.

Direct costs, repetitive and consistent in nature, are best driven by **volumetric measures** that are causing the activity to be performed and therefore the cost to be incurred. The formula approach is too broad brush for this application and the time sheet approach does not provide a better result and is more costly and time consuming to administer. These cost types are best measured in the application of a fully embedded costing philosophy.

Indirect Costs

As these activities and related costs typically directly support other activities, they are usually best handled in the same proportion as the activities, which they are supporting. This normally takes the form of a composite ratio **(formula)** of the allocation split of the activities that are being supported. These cost types are more commonly measured utilizing a fully embedded costing philosophy.

Corporate Sustaining Costs

The corporate sustaining cost category is best suited to a **formula based** cost allocation approach, as these costs are normally consumed based on high-level factors such as revenues, rate base and salaries. This cost pool is typically only allocated, if at all, in the application of a fully embedded costing philosophy. The true relationship between activity and cost object is not very clear using this approach, however, a more detailed cost driver would have no more validity and therefore would not produce a more supportable result.

TERASEN GAS INC.

2004 – 2007 MULTI-YEAR PERFORMANCE BASED RATE PLAN
MISCELLANEOUS INFORMATION PERTAINING TO THE SETTLEMENT

The following material deals with two matters:

- Responses to issues and questions raised at the October 15, 2003 Customer Advisory Council meeting.
- An application to be filed with respect the Company's Gas Supply Core Market Administration budget

Customer Advisory Council Meeting Follow-up

Established by the July Settlement Agreement, the Customer Advisory Council is a forum for customer groups and Terasen Gas to meet twice yearly for the purpose of communicating and resolving customers' concerns that may have arisen during the year. The first of these meetings was held on October 15, 2003 at the Terasen Centre, 1111 West Georgia, Vancouver, BC.

The issues discussed at the meeting were as follow:

- Customer Care Issues
  - Customer Satisfaction
  - "Meter to Cash" Process
- Potential Load Building Initiatives
- Regulatory Update
- Utilities Strategy Project – Terasen Gas Inc. and Terasen Gas (Vancouver Island) integration
- Other Items

Minutes of the meeting were recorded and copies forwarded to all attendees as well as to those invited but unable to attend. Several questions arose in the meeting for which full responses were not available at the time. Terasen Gas now offers the following responses to those questions:

1. Question: What is the ratio of lock-offs for residential vs. commercial customers?

   Response: At this time, Terasen Gas does not have this information available. The data collected on lock-offs does not distinguish by customer class. The Company will endeavour to provide more details on this issue at the next Customer Advisory Council meeting.

2. Question: What is the number of security deposit requests that relate to brand new customers v. reconnect customers?

Response: Currently Terasen Gas is reviewing ways to improve the statistical reporting process in the area of collections so as to provide better trend analysis. Once this is part of the standard reporting package, the Company will be in a better position to share such information with customers at the next Customer Advisory Council meeting.

3. Question: Does Terasen track family breakups as a leading indicator for credit problems.

Responses: To collect such data from customers would be difficult, as customers may not wish to report their personal circumstances. Also, such collection of information may not be allowed under privacy legislation. It may be more practical to track trends between disconnection of services and some external economic indicators which may assist in better understanding customer actions and reactions and preparing for forecast changes in volumes.

4. Question: Does it seem fair to discontinue the GCRA exit fee rider when the GCRA balance reaches zero?

Response: The GCRA Exit Rider was first introduced in January 2000 after significant gas price volatility in 1999 had caused the GCRA balance to swing from a surplus to a deficit during 1999. The need to retain the GCRA Exit Rider was exacerbated by the large GCRA deficit accumulation in 2000 for which the Commission ordered a three-year recovery period. While three years later gas price volatility remains a concern, the regular quarterly commodity and GCRA review process implemented by the Commission in 2001 (BCUC Letter No. L-5-01) has assisted in managing the GCRA balance down close to zero in the three-year time frame. Going forward the quarterly review process coupled with discretion for the Company to apply for rate adjustments at other times, the Company anticipates the GCRA balance will be kept at modest levels and will just as likely be a deficit or surplus balance. The introduction in 2004 of commodity unbundling for commercial customers will introduce further impetus to keep gas cost deferral accounts to a minimum. With the potential for greater numbers of customers moving between sales, transportation service and other rate offerings the process of administering an exit rider will become very complicated. The GCRA Exit Rider expired on September 30, 2003. With smaller future GCRA balances diminishing the likelihood of migrating customers over or underpaying commodity costs while on sales rates and to avoid the administrative complexities of maintaining a GCRA exit rider going forward, the Company does not intend to renew the exit rider at this time.

5. Comment: Terasen should continue to refine its education around PBR because there exists some confusion for customers about the relationship between PBR and Unbundling.

Response: Terasen Gas will provide information addressing this issue in its next quarterly newsletters to all commercial customers.

Gas Supply 2004 Core Market Administration Budget

In keeping with the intent of the 2004 – 2007 PBR Settlement to keep customers informed of the Company's activities, Terasen Gas is hereby advising stakeholders of its intent to file an application with respect to its 2004 Core Market Administration ("CMA") budget. The CMA budget is related to the gas supply function and is included in customers' rates by way of a small charge as part of the gas cost recovery charges.

In 2003 the gross CMA budget is $1.7 million. The amount included in the gas cost recovery charges of Terasen Gas Inc. customers is $1.6 million since payments received from Terasen Gas (Vancouver Island) ("TGVI") for managing TGVI's gas supply are netted against the gross CMA budget.

For 2004 Terasen Gas will apply to increase the gross CMA budget by about $130,000 to cover the annual licensing fees for new energy management and planning software systems. In addition to providing energy management services for TGVI, Terasen Gas has recently received BCUC approval of another energy management services agreement with Pacific Northern Gas. In spite of the application seeking an increase in the gross 2004 CMA budget the net amount to be charged to Terasen Gas' customers for 2004 will decrease because the additional energy management services income will more than offset the $130,000 increase.

Terasen Gas is seeking further opportunities to market energy management services to third parties and would like to establish an incentive to generate such fees similar to the 50/50 sharing arrangement for O&M efficiencies under the 2004 – 2007 PBR Settlement.

Terasen Gas

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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www.terasen.com

November 17, 2003

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

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

Dear Sir:

RE: Terasen Gas Inc.
2004 – 2007 Performance Based Rate Plan
2003 Annual Review - November 21, 2003
BCUC Order No. G-66-03
Response to BCUC Staff Information Request No. 1

Enclosed please find 15 copies of Terasen Gas' responses to BCUC Staff Information Request No. 1 relating to the Annual Review advance material, filed on October 31, 2003. Please note that the response to Question 1.1 is not yet complete, but will be provided to the Commission and Annual Review interested parties as soon as it is available.

We trust the enclosed is satisfactory. Should further information and/or clarification be required, please contact the undersigned or Dave Perttula at (604) 592-7470.

Yours very truly,

TERASEN GAS INC.

Original signed by Scott Thomson

Scott Thomson

Encl.

c. 2004 – 2007 PBR NSP Participants
Interested Parties

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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November 19, 2003

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

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

Dear Sir:

RE: Terasen Gas Inc.
2004 – 2007 Performance Based Rate Plan
2003 Annual Review - November 21, 2003
BCUC Order No. G-66-03
Response to BCUC Staff Information Request No. 1

The response to Question 1.1 of BCUC Staff Information Request No. 1 was not completed for filing with the remainder of the responses on November 17, 2003. The response is now complete and has been inserted into the original document that contains the balance of the responses.

Since adding in the response to Question 1.1 has altered the page numbering of the original document, Terasen Gas now resubmits the entire responses to BCUC Staff Information Request No. 1. The only difference between this submission and the November 17, 2003 submission is the inclusion of the response to Question 1.1 and all other responses provided in the earlier filing remain unchanged. Please replace the responses submitted on November 17, 2003 with the attached responses.

Yours very truly,

TERASEN GAS INC.

Original signed by Dave Perttula
on behalf of Scott Thomson

Scott Thomson

Encl.

c. Registered Participants

1.0 Customer Additions – Rates 1, 2, 3/23 Total Year End Customer Additions Table Tab A-4, p. 3-4

1.1 *Please restate the Total Year End Customer Additions Table to provide the components of customer additions for each year of 2000 to 2002 (actual), 2003 (projected) and 2004 (forecast) in the following format:*

		Projection 2003
Residential –	gross additions	
	disconnections	
	reconnections	
	Net Total	8,700
Commercial-	gross additions	
	disconnections	
	reconnections	
	Net Total	-890
Total Customers Year End		**777,863**

Response

The table below sets out estimates of the requested customer additions components from 2000 to 2004. Please note that the table in Tab A-4, Page 4 on which the question is based pertains to residential and commercial rate classes only (Rates 1, 2, 3 and 23) so the information in the table below also only applies to these classes.

Terasen Gas does not have historical information in all of the requested categories identified in the question. The Company has historical information on the net customer additions and the disconnections. The other two items, gross additions and reconnections, have been estimated using reasonable assumptions. Terasen Gas has historical information for the interior of the province supporting a reconnection rate of 97% of disconnected customers. The Company considers it reasonable to assume that historically the Lower Mainland reconnection rate was at a similar 97% level. The decrease in 2003 to a 92% reconnection rate is believed to be a one-time phenomenon linked to the factors described in the paragraphs below. For 2004 Terasen Gas expects the reconnection rate to return to a level approximating the historical experience of 97%. The reconnection rates of 92% in 2003 and 97% for the other years have been used to estimate the reconnections from the known annual disconnections. The gross customer additions were estimated by working up from the known net customer additions, the known disconnections and the estimated reconnections. The results in the table are reasonable but since some of the line items have been estimated the overall results should be considered directional.

The main contributors to the Company's expectation that the reconnection rate will drop in 2003 to 92% are the repatriation in July 2002 of Lower Mainland customers from the BC Hydro billing system and the credit and collections management program undertaken by Terasen Gas in 2003.

Repatriation of the Lower Mainland customer base introduced a number of significant changes in terms of billing and collections management for both customers and the Company. After July 1, 2002 Lower Mainland customers began receiving for the first time separate gas and electricity bills. The frequency of gas bills was changed from bi-monthly for the combined gas/electricity bill to monthly for the gas only bills from Terasen Gas. The Company believes that seeing gas charges on a completely separate basis for a number of the low-volume non-essential use customers has triggered many of the disconnections where reconnections are not expected. Also, under the combined billing arrangement BC Hydro had the leverage of being able to disconnect the electricity with the secondary effect of cutting off gas since furnaces and other gas appliances do not operate without electricity. Many of the gas disconnections under BC Hydro were these so-called “soft” disconnections where Terasen Gas did not physically shut off the gas flow. BC Hydro did not provide Terasen Gas with information on the numbers of this type of disconnection but it is, nevertheless, a significant reason why disconnection activity in the Lower Mainland has risen significantly since repatriation.

In addition to the repatriation changes affecting Lower Mainland customers, the Company in 2003 has been engaged in a bad debt management program across its service territory in which its credit and collections policies have been more diligently and consistently applied. Terasen Gas believes there will be some moderation of disconnection/reconnection activity as customers adjust to the Company's policies. Also, Terasen Gas currently expects rate decreases in 2004 which should assist in reducing the level of credit management activities. The current high levels of disconnection/reconnection activity are not unique to Terasen Gas. The Company has been advised that gas and electric LDCs in other jurisdictions have also experienced large increases in these activities.

TERASEN GAS INC.

Customer Additions (Rates 1, 2 and 3/23)

	2000 Actual	2001 Actual	2002 Actual	2003 Projected	2004 Forecast
Gross Additions	7,400	5,300	8,300	7,800	9,400
Disconnections	(10,900)	(12,200)	(17,500)	(50,000)	(30,000)
Reconnections	10,600	11,800	17,000	46,000	29,100
Net Additions	7,100	4,900	7,800	3,800	8,500
Year-end Customers	757,400	762,300	770,100	773,900	
Rate 2 Adjustment				(1,300)	
Revised Year-end Customers				772,600	781,100

As Terasen Gas does not track disconnections or reconnections by rate class, it is not possible to provide a breakout of the components of customer additions by residential and commercial customers.

1.2 *Please explain the Reconnection Adjustment of -4,000 (Year 2003) in the Table*.

Response

This adjustment represents the number of "locked off" residential and commercial customers not expected to reconnect to the distribution system. It was calculated by applying the estimated September 2003 year-to-date reconnection rate of 92% to 50,000 affected customers. Although the reconnection rate remains high, the large number of impacted customers implies that a higher number of accounts will not renew their accounts in 2003.

As this loss stems from changes in customer behavior associated with the repatriation of Lower Mainland customers from the BC Hydro billing system and more consistent application of collection procedures, it is considered a one time adjustment. The expected Total Customer Count at year end 2003 is therefore revised to 772,580 from 777,863 – including the Lower Mainland Rate 2 Repatriation Adjustment.

1.3 *Please comment on the additions/disconnections trends from 2000 to 2003 and explain the trend assumptions used in the 2004 forecasts.*

Response

The 2002 disconnection experience in the Interior was used to estimate the normal rate of reconnection following customer disconnection at approximately 97%. After the first 9 months of 2003, this figure was revised downward to 92%.

These revisions in the reconnection rate result from changes in customer behavior associated with the repatriation of Lower Mainland customers and more consistent application of collection procedures. Once these changes were implemented in 2002, the number of customer lock-offs grew. Projections for 2003 now exceed 50,000 – a five-fold increase from the year 2000. If the October 2003 reconnection rate of 92% is applied to this number, only 46,000 disconnected customers will return by year end. This leaves an estimated deficit of some 4,000 customers.

To illustrate the impact of these policy changes on net accounts, historical data on lock-off disconnections is presented in Table 1.3 below.

Table 1.3

Year	Interior	Lower Mainland	Total
2000	8,071	2,824	10,895
2001	8,679	3,498	12,177
2002	10,717	6,816	17,533
2003P	16,218	34,231	50,449

1.4 *Please comment on the characteristics of customer disconnections over the years (e.g. customers switching to alternative supply, seasonal disconnections only, business closure or migration from the service area, etc.)*

Response

Although Terasen Gas does not systematically identify every reason for customer connection and disconnection, there has been a tendency for some residential and commercial customers to “seasonally disconnect” in the spring and “seasonally reconnect” in late fall. This behavior is presumably motivated by a desire to avoid administrative charges during the summer months – although customers actually derive no real economic benefit from the practice. When reconnection charges and interest on unpaid accounts are considered, it is generally cheaper to maintain service throughout the year. With customer education and more effective management of bad debt, this behavior is expected to diminish. Marketing managers at Terasen Gas are actively seeking ways to inform the public and control costs.

Migration between service areas does not normally affect the net customer count since old account numbers are reactivated with each reconnection – unless that migration includes a change of rate classification.

Disconnections due to business closure and fuel switching no doubt increase as natural gas commodity prices rise and economic hardship increases, but these effects are already reflected in the models used by Terasen Gas to forecast residential and commercial account growth.

2.0 Customer Additions – Industrial Tab A-4, p. 7

Please prepare a table in the same format as IR 1.1 for industrial customer additions from 2000 to 2004. Please identify the incremental changes, both in the total customers and total PJ per annum for the industrial rate classes.

Response

Terasen Gas does not record the disconnection and reconnection of Industrial Customers. Only the total number of customers and energy consumption is tracked, and this information is provided below in Table 2.0.

The largest contributor to account growth in Industrial Customers is Rate Schedule 25. The total number of Rate 25 customers in 1999 was 165 compared to the 2003 year end projection of 505. Only 8 additional customers in Rate Classes 7, 22 and 27 account for the remaining increase.

Note that Rate 22 includes Rate 22A and 22B. Rate 5 is treated elsewhere as firm load and therefore excluded.

TABLE 2.0

Year	Total Customers (7, 22, 25, 27)	Absolute Variance	Total Energy (PJ)	Absolute Variance
1999	318	-	61.7	-
2000	353	35	60.6	-1.1
2001	475	122	56.0	-3.4
2002	656	181	60.1	+4.1
2003P	666	10	58.1	-2.0
2004F	666	0	57.8	-0.3

3.0 Use per Customer-Table on Historic and Forecast Usage, Tab A-4, pp. 4-6

3.1 *Please restate the table on page 6 to also show the average annual gas charge for a typical customer in each rate class for each year from 1999 to 2004.*

Response

The table below shows the average annual gas charge for a normalized use customer in Rates 1, 2 and 3 for each year from 1999 to 2004. Rate 23 customers are transportation service customers and therefore have no commodity related charge. The annual gas charge for each year consists of the gas cost recovery charge and the GCRA rider 6 multiplied by the average annual GJ. Rate changes occurring during the year were pro-rated by the applicable monthly volumes for each rate class. The 2004 gas cost charge consists of the existing 2003 gas cost recovery charge and GCRA rider 6 multiplied by the forecast annual 2004 usage. A separate gas cost flow-through application will be made in early December 2003 for any changes to the gas cost recovery charge and GCRA rider 6 that would be effective on January 1, 2004. At this time it is expected that the gas cost recovery charge and GCRA rider 6 will be reduced when the next gas cost flow-through application is made.

Average Annual Gas Charge for a Normalized Use Customer - Rates 1, 2, 3 & 23

	1999	2000	2001	2002	2003	2004
Rate 1						
Typical Use Rate (GJ)	116.7	111.7	100.5	105.6	100.4	104.7
Average Annual Gas Charge	$382	$573	$837	$697	$763	$867
Rate 2						
Typical Use Rate (GJ)	339.4	324.6	305.4	301.8	291.4	300.1
Average Annual Gas Charge	$1,146	$1,706	$2,579	$2,035	$2,244	$2,516
Rate 3						
Typical Use Rate (GJ)	3,981.5	3,659.5	3,332.1	3,378.1	3,326.5	3,342.4
Average Annual Gas Charge	$12,003	$17,666	$26,801	$21,559	$24,646	$26,886
Rate 23						
Typical Use Rate (GJ)	6,945.2	6,446.8	5,802.4	5,281.1	4,930.6	5,301.2
Average Annual Gas Charge	$0	$0	$0	$0	$0	$0

3.2 *Please clarify the statement on page 4 that "To maintain an overall neutral impact, the use per account has been adjusted concurrent with the reduction in Rate 2 customer numbers starting in 2004." Please explain what neutral impact is being referred to in that statement. Please explain why adjustments for this impact are not being made to the 2003 projected use per customer*.

Response

During repatriation of the BC Hydro Billing System in 2002, it was discovered that 1,283 Rate 2 customers had been double-counted in prior years. To ensure that the calculation of forecasted Commercial Rate 2 usage for the 2003 Revenue Requirement was consistent with consumption history, the double-counted customers were retained in estimates for 2002 and 2003. This maintained a neutral impact by eliminating the effect of the double-counted customers on the estimated year over year change in total Rate 2 energy. Recall that total energy is estimated by multiplying forecasted accounts by usage.

For similar reasons, an adjustment for this impact was in fact made for 2003 Rate 2 usage by removing the over-counted customers. This adjustment was necessary because 2004 usage is based on 2003 year end results which if left unadjusted would render 2004 use per account artificially low.

The error will be permanently removed December 31, 2003 in accordance with the intentions outlined in Section F, Pages 5 and 6 of the Terasen Gas 2004 – 2008 Multi-Year PBR Application.

3.3 *Please confirm that the historical usage for Rate 2 customers prior to 2004 in the Table on page 6 are all underreported because of the error in recording 1,283 transportation customers as Rate 2 customers. If yes, please provide the true historical Rate 2 usage from 1999 to 2003 to facilitate comparison with the 2004 adjusted forecast use rate.*

Response

It is confirmed that all the reported amounts are understated for Rate 2. However as was covered in the submission noted in the response to 3.2 above, both the forecast use per account used for rate setting purposes and the calculated actual use per account that was used for RSAM purposes were based on the same underlying customer counts.

Rate 2 historical use per customer prior to 2004 is underreported. Estimated "true" usage can be calculated by removing 1,283 double-counted customers for the years 1999 through 2002. The results are presented in Table 3.3 below. Note that values are weather normalized, and that 2003 usage is already adjusted for the error in customer accounts.

Table 3.3

Year	Estimated "True" Usage (Terasen Gas RS 2)
1999	346.8
2000	329.0
2001	310.6
2002	305.9
2003	291.4

4.0 Rates 1, 2, 3 and 23, Tab A-4, pp. 4-6

4.1 *The material on page 5 states that further downward pressure in residential use rates could be related to strata developments that shift residential consumers into large commercial or industrial rate groupings. Please comment on the estimated impact for each rate class.*

Response

Terasen Gas believes that downward pressure on usage by residential customers is reasonable given that many Housing Strata contain smaller, non-detached units. But when householders collectivize under Rate Classes 3, 5, 23 or 25, the estimation of usage by residence becomes extremely difficult. Without separate meters for each Strata member, Terasen Gas cannot properly compare or aggregate results with customers who remain in Rate Class 1. So although it is reasonable to assume that overall residential usage will fall, Rate Class 1 usage could rise if multiple housing estates opt for Commercial-Industrial Rate Classes. This would bias Rate Class 1 toward higher usage single detached houses and render it unrepresentative of residential customers as a whole. .

At present it is too early to define what the long-term impact of residential usage in Commercial and Industrial Rate Classes will be. A proper analysis of residential usage of this kind requires knowledge of Strata membership since housing estates may contain anywhere from a few dozen to several hundred residents. As Terasen Gas does not have this information (it requires a special survey), the impact of residential usage on specific Rate Classes cannot be calculated as yet.

4.2 *Terasen forecasts on page 6 that Rate 1 usage will rise from the currently projected 100.4 GJ (2003) to 104.7 GJ (2004). Please provide the underlying forecast assumptions for (i) electricity rate increase for 2004 and (ii) the natural gas commodity price change from 2003 prices.*

Response

Terasen Gas makes no specific assumption about electricity rates, but does believe that some sort of increase is probable in 2004 based on statements from Hydro itself concerning its impending rate filing. A more definitive assessment of the possible impacts awaits that filing, but Terasen believes that it will moderate some of the competitive impacts felt in recent years.

Regarding the outlook for commodity prices, Terasen Gas expects total costs to be slightly lower for firm customers in 2004. Compared to the forecast submitted in support of the 2003 Annual Review, gas costs charged to customers are expected fall during 2004. Although the exact amount is yet to be determined, reduction may be as high as 10% if commodity prices continue at current levels.

4.3 *Please clarify the statement on page 5 that describes adjusting use rates in Rates 2, 3, and 23 where the "Aggregated mean usage for these customers is therefore expected to be about 2.3 percent above 2003." Please describe how the 2.3 percent is calculated.*

Response

This calculation is an average change in the combined use for Rates 2, 3, and 23 between the 2003 Year End Projections and the 2004 Forecast. It is calculated by summing all the energy consumed by Commercial Rate Classes and dividing by the annual average number of accounts.

The 2.3% calculation is based on the numbers presented below in Table 4.3. Note that, for proper comparison, the 1,283 double-counted Rate 2 customers are added back into the account total for 2004.

	2003P	**2004F**	**Variance**
Total Energy	43,000.0	44,100.0	
Average Accounts	78,400	78,600	
Consolidated Usage	548.5	561.1	2.3%

5.0 DSM

Tab B-3, p. 8 and BC Gas 2003 Revenue Requirements Application Exhibit 21 (attached Tab 2, p. 5)

5.1 *Please provide the underlying analysis (i.e., cost and benefits for each program) for the Total Resource Cost Test net benefit result of $6.9 million (as reported in Tab B-3, p. 8). Please link the analysis and result to the table on page 8 that summarizes participants and savings by program.*

Response

The following table illustrates the projected costs and benefits associated with each program in the 2003 DSM portfolio as presented in the DSM Status report, page 8.

2003 DSM PROGRAMS - Forecast Costs and Benefits ($000)					
	Heating System Upgrade	*Fireplace Pilot	Utilization Advisory	Destination Conservation	Total Program Portfolio
Total Participant Costs	$3,136	$1,100	$675	$92	$5,003
Total Program Costs (direct)	$561	$50	$35	$0	$646
NPV Avoided Costs	$9,316	$1,148	$1,729	$398	$12,591
TRC Net Benefit	$5,619	-$1	$1,019	$306	$6,943

* Implementation of the Fireplace Upgrade Pilot Program to be delayed to the first quarter of 2004.

5.2 *Exhibit 21 includes an attached Tab 2, p.5 that reports a TRC net benefit of $691,000 for 2001 programs. Please describe the incremental program changes or other factors that explain the tenfold increase to the TRC net benefit in 2003.*

Response

As shown in the response to Question 5.1 above, the major contributor to the portfolio TRC Net Benefit for 2003 is the Heating System Upgrade program. This program, with certain variations, was also offered in 2001 and 2002. The TRC Net Benefit is generally proportional to customer participation rates each year with the exception that utility program costs (that are included as part of the TRC test) may not be proportional to customer participation rates. The $691,000 TRC Net Benefit projected and reported in the referenced report for 2001 reflected significantly lower participation rates than those projected for 2003:

Year	Projected Participants	Actual Participants
2001	800	1423
2002	2000	2785
2003	4000	-

The projection for 2003 is therefore five times the projected 2001 level. Program costs per participant have also been reduced significantly through economies of scale and through contributions of partners, most notably NRCan in both 2002 and 2003. Other program changes since 2001 such as the re-introduction of Destination Conservation and the increased number of participants in the Utilization Advisory program have also made positive contributions to the 2003 TRC Net Benefit as indicated in the response to Question 5.1 above.

6.0 BC Gas 2003 Revenue Requirements Decision, p. 34

6.1 *Please provide a summary of total actual and projected DSM expenditures from 1999 through 2003. Where possible, please provide this information broken down by DSM program. Please discuss the underlying trend in these expenditures*.

Response

Overall, annual DSM operating and customer incentive expenditures have remained relatively constant since 2000 (see table below). Terasen Gas has been able to moderate its costs through partnering with other interested parties. For example, in its 2003 Heating System Upgrade Program, Terasen is partnering with Natural Resources Canada, BC Hydro, Aquila Networks and 15 heating system suppliers. In addition, the additional customer incentives offered by program partners help to encourage growth in program participation, which in turn increases the cost effectiveness of the programs overall.

In 2000 the Company launched a major awareness campaign based on the ‘Hot Tips’ booklet to help residential customers cope with rapidly rising commodity costs. In 2001 there was a return to incentive based programs which have since been the emphasis of DSM in the residential sector.

DSM Operating Expenditures 1999-2003 ($000)

	1999	2000	2001	2002	Ytd Oct 2003
Evaluation and Research	$ 10	$ 92	$ 11	$ 62	$ 50
Education and Awareness	$ -	$ 803	$ 95	$ 66	$ 33
Load Research	$ 147	$ 163	$ 147	$ 145	$ 109
Residential Programs* (Tune-up, Heating System Upgrade and Weatherization)	$ 85	$ 3	$ 1,109	$ 857	$ 273
Heatsaver Program	$ 92	$ -	$ -	$ -	$ -
Efficient Boiler Program	$ 62	$ 69	$ 42	$ 20	$ -
Commercial Utilization Advisory	$ -	$ -	$ -	$ 22	$ 35
Firm to Interruptible	$ 7	$ -	$ -	$ -	$ -
Destination Conservation	$ 30	$ 69	$ 2	$ -	$ 69
Other (Administration, Program Development)	$ 194	$ 135	$ 218	$ 268	$ 287
Actual Operating Expenditures (including labour and expenses)	**$ 627**	**$ 1,334**	**$ 1,624**	**$ 1,439**	**$ 856**
Forecast Operating Expenditures	**$ 796**	**$ 1,342**	**$ 1,627**	**$ 1,627**	**$1,400**

*Program costs for residential program activities have been aggregated in some years due to offers running concurrently. In 1999 and 2000, the expenditures reflect the High Efficiency Heating System Upgrade program only; whereas in 2001, costs reflect 3 programs - the Furnace Tune-up, the High Efficiency Heating System Upgrade and Weatherization program; and, 2 programs in 2002: the Furnace Tune-up and High Efficiency Heating System Upgrade. In 2003, the High Efficiency Heating System Upgrade is the only program offered.

DSM Customer Incentive Expenditures 1999-2003 ($000)

	1999	2000	2001	2002	Ytd Oct 2003
Actual Customer Incentive Expenditures	**$ 1,151**	**$ 1,578**	**$ 1,380**	**$ 1,227**	**$ 133**
Forecast Customer Incentive Expenditures	**$ 1,703**	**$ 836**	**$ 1,393**	**$ 800**	**$850**

6.2 *Please provide a supporting basis for setting a 2004 benchmark amount of total DSM expenditures equal to the maximum $1.5 million amount provided for under the DSM deferral account for incentive grants.*

Response

The following table sets out the DSM program customer incentive forecast for 2004:

Forecast DSM Incentive Requirements for 2004

Program	Participants	Incentive forecast ($000)
Energy Star Heating System Upgrade	4500	$680
New Construction Energy Star Heating Systems	2000	$300
Residential Fireplace Upgrade Pilot	1000	$100
Commercial Boiler Upgrade	15	$240
Customized Measure Support	10	$150
Destination Conservation	20	$30
Total DSM Portfolio	**7,545**	**$1,500**

7.0 Deferral Accounts

Reference: Section A, Tab 3, p. 11.1; Section A, Tab 4, pp. 9 and 14.1; Section A, Tab 8, p. 4.1 and BCUC IR 8.2 and 8.3 TGI 2004-2008 PBR Application

The deferral accounts in Section A, Tabs 3 and 8 show 2003 and 2004 gross addition debits to SCP Net Mitigation Revenues and SCP PG&E Contract Cancellation as listed below:

Deferred Charges-Gross Additions	**2003**	**2004**
SCP Net Mitigation Revenues	916,000	639,000
SCP PG&E Contract Cancellation	1,400,000	3,000,000

For 2004, SCP Third Party firm revenues of $7.8 million are forecast and additional SCP Mitigation Revenue Margin remains at $1 million per year on Section A, Tab 4, page 9. The 2004 SCP Third Party Revenues on Section A, Tab 4, page 14.1 has revenue and gross margin of $8,820,000.

Please update the tables provided in BCUC IR 8.2 and 8.3 of the TGI 2004-2008 PBR Application to show the SCP Net Mitigation Revenues and SCP PG&E contract cancellation for 2003 and forecast for 2004 in the 2003 Annual Review material.

Response

The table below shows the calculations of the projected gross additions in 2003 for the SCP deferral accounts. The table also includes the details of the projected 2003 SCP Third Party Revenues.

2003 SCP DEFERRAL ADDITIONS
($000)

SCP Net Mitigation Revenues

Spot Revenues included in Test Year	$1,300
Less: Projected Spot Revenues	(384)
Total Deferral Additions (Sec A, Tab 8, Pg 4.1, Line 52)	$916

SCP PG&E Contract Cancellation

PG&E – SCP Third Party Firm Revenues in Test Year	$3,600
Less: Projected Mitigation Revenues using PG&E Capacity	(2,200)
Total Deferral Additions (Sec A, Tab 8, Pg 4.1, Line 54)	$1,400

PROJECTED 2003 SCP THIRD PARTY REVENUES
($000)

PG&E Revenues	$3,600
B.C. Hydro Firm Contract	3,600
Subtotal	7,200
Spot Revenues	1,300
Total	$8,500

The table below shows the calculations of the forecast gross additions in 2004 for the SCP deferral accounts. The table also includes the details of the Forecast 2004 SCP Third Party Revenues.

2004 SCP DEFERRAL ADDITIONS
($000)

SCP Net Mitigation Revenues

Spot Revenues included in Forecast Revenue Requirements	$1,000
Less: Forecast Spot Revenues	(361)
Total Deferral Additions (Sec A, Tab 3, Pg 11.1, Line 50)	$639

SCP PG&E Contract Cancellation

PG&E – SCP Third Party Firm Revenues in Revenue Requirements	$3,000
Less: Forecast Mitigation Revenues using PG&E Capacity	0
Total Deferral Additions (Sec A, Tab 3, Pg 11.1, Line 52)	$3,000

FORECAST 2004 SCP THIRD PARTY REVENUES
($000)

PG&E Revenues (Jan 1 to Oct 31, 2004) [BCUC Letter No. L-48-02]	$3,000
Replacement Contract (Nov 1 to Dec. 31, 2004)	1,220
B.C. Hydro Firm Contract	3,600
Subtotal	7,820
Spot Revenues	1,000
Total (Sec A, Tab 4, Pg 14.1, Line 26)	$8,820

Scott A. Thomson
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November 28, 2003

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

Attention: Mr. R.J. Pellatt
Commission Secretary

Dear Sirs:

RE: Terasen Gas Inc. ("Terasen Gas")
2003 Annual Review – BCUC Order No. G-66-03
Additional Information Requested at the
November 21, 2003 Annual Review Meeting

Participants in the November 21, 2003 Annual Review meeting requested additional information with respect to residential and commercial use rate decreases and related revenue forecast changes, and possible effects on future revenue requirement increases. An assessment of the revenue margin to cost ratios for various rate classes was also requested.

Terasen Gas indicated that it would provide the requested information for various use rate scenarios in order to cover the range of likely outcomes.

The attached tables provide the resulting revenue requirement changes and other information for high, low and intermediate use rate base cases. A fourth case provides an alternate version of the low use case where the use rate declines are phased in over the remaining three years of the 2004 – 2007 PBR Plan. For ease of reference the scenarios are identified by the residential use rate assumption, but in each case corresponding adjustments have been applied also to the use rates of the commercial classes.

The following cases have been evaluated:

- Base case – use rates at applied-for 2004 levels (104.7 GJ/year for residentials) for the four-year PBR period.
- High use rate – residential use rate increases to 106.4 GJ/year in 2005 and remains through to 2007.
- Low use rate - residential use rate decreases 96.6 GJ/year in 2005 and remains through to 2007.
- Low use rate phase-in - residential use rate decreases in equal increments from 104.7 GJ/year in 2004 to 96.6 GJ/year in 2007.

Background for Case Selection

In response to the Annual Review request, Terasen undertook to provide an analysis of the impact of scenarios taken from the most probable range of use rate forecasts.

The high and low use rate cases were established based on a statistical probability range of plus or minus 15% (i.e. a 70% confidence interval with 15% of results above the high case and 15% below the low case). The base case, which maintains the 2004 use rates throughout the four-year period of the PBR, is near the middle of the probability range. The statistical range is only part of the story.

Intuitively, there is a short-term resistance level that tends to create a floor for use rates. This floor occurs because periods of perceived high prices encourage customers to quickly implement available technologies that reduce gas demand. Further decreases are then lagged by the time required to develop and adopt new innovations. Based on the experience of 2001 and 2003, this short-term floor level appears to be around 100 GJ per year for Rate 1 customers.

On the other hand, improvements in the price competitiveness of natural gas relative to electricity or improvements in the economic climate are unlikely to result in significant increases in gas use by residential or small commercial customers. While there is some potential for an upward movement in gas use as customers relax their use of “blankets and sweaters” to provide comfort on colder or damper days, customers are unlikely to reverse investment in energy saving devices and equipment. The largest unknown is the amount of reduction in gas consumption attributable to increased electric space heating (baseboard and other) and the impact that switching back to natural gas might have.

Discussion of Results

The requested information is provided in three tables attached to this letter. Table 1 provides the estimated revenue requirement increases of the various cases and also demonstrates the effect of use rate changes through comparisons of the various cases to the base case. Table 2 provides a summary of the factors contributing to the year-to-year revenue requirement changes for the base case. Table 3 provides a short-cut estimate of the revenue to cost ratios for the firm service classes under the various scenarios over the term of the PBR.

The results in the base case represent a reasonable outlook for future revenue requirement rate changes at the current allowed return on equity. After 2004 the rate changes average about 1% per year which is in line with previous estimates of the rate increases to fall out of the Settlement. It should be noted that these rate changes do not include any benefit of PBR earnings sharing which the Company anticipates will affect rates positively.

The Company considers the low case to provide a fair limit on the rate increases arising from continued use rate declines. The residential consumption level decrease to 97 GJ/year would add an additional 4.3% to the delivery rate increases under the PBR. If use rate decreases continued to the degree indicated by the low case it is more likely the effect would be phased in over the three years and would add about 1.4% per year to the rate changes from other factors.

Use rate increases above the 2004 forecast levels are likely to be smaller in magnitude than the potential decreases. The high use case in Table 1 (with the residentials at 106.4 GJ/year) would reduce revenue requirements in 2005 by $11.2 million equivalent to a 2.3% margin decrease.

The margin to cost ratios on Table 3 should be viewed as directionally indicative only since a number of simplifying assumptions were made in order to provide these estimates in a one-week period. A full cost of service study normally takes much longer to complete even for a single scenario. With those caveats the margin to cost ratios are generally stable across the multi-year period and across the varying use rate assumptions. While margin to cost ratios of the industrial and general firm service classes appear higher than after the last rate design proceeding, it is not certain if these are the result of the simplified approach or actual changes arising differences in the underlying cost structure and customer class composition.

Summary

In summary, the effect of further use rate changes on future revenue requirements in the 2004 – 2007 PBR term is likely to fall in the range of -2.3% to +4.3%. There is a reasonable chance that future use rate changes from those applied for in 2004 will not be large.

I trust these comments and attached tables provide the information sought by Annual Review participants.

Yours very truly,

TERASEN GAS INC.

Original signed by Scott Thomson

Scott A. Thomson

encl.

c. 2003 Annual Review Registered Participants

TERASEN GAS INC.
REVENUE REQUIREMENT SCENARIOS UNDER VARIOUS RESIDENTIAL AND COMMERCIAL USE RATE ASSUMPTIONS

Table 1

Line No.	Particulars	Forecast Revenue Requirement Changes				Change from Base Case			
		2004	2005	2006	2007	2004	2005	2006	2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Base Case (Residential Use Rate at 104.7 GJ/Year Throughout)**								
2									
3	Annual Revenue Requirement Increase/(Decrease)								
4	Amount ($000)	$19,150	$1,518	$9,249	$4,337				
5	% of Gross Margin	4.3%	0.3%	2.0%	0.9%				
6									
7	Cumulative Revenue Requirement % Increase	4.3%	4.6%	6.7%	7.6%				
8									
9									
10	**High Use Rate Case (Residential Use Rate at 106.6 GJ/Year for 2005 - 2007) ***								
11									
12	Annual Revenue Requirement Increase/(Decrease)								
13	Amount ($000)	$19,150	($9,684)	$9,276	$4,345	$0	($11,202)	$27	$8
14	% of Gross Margin	4.3%	-2.0%	2.0%	0.9%	0.0%	-2.3%	0.0%	0.0%
15									
16	Cumulative Revenue Requirement % Increase	4.3%	2.2%	4.2%	5.1%	0.0%	-2.4%	-2.5%	-2.5%
17									
18									
19	**Low Use Rate Case (Residential Use Rate at 96.6 GJ/Year for 2005 - 2007)***								
20									
21	Annual Revenue Requirement Increase/(Decrease)								
22	Amount ($000)	$19,150	$20,754	$9,277	$4,361	$0	$19,236	$28	$24
23	% of Gross Margin	4.3%	4.6%	2.0%	0.9%	0.0%	4.3%	0.0%	0.0%
24									
25	Cumulative Revenue Requirement % Increase	4.3%	9.1%	11.3%	12.3%	0.0%	4.5%	4.6%	4.6%
26									
27									
28	**Low Use Rate Case (Use Rate Decreases Phased In)***								
29									
30	Annual Revenue Requirement Increase/(Decrease)								
31	Amount ($000)	$19,150	$7,931	$15,795	$11,180	$0	$6,413	$6,546	$6,843
32	% of Gross Margin	4.3%	1.7%	3.4%	2.3%	0.0%	1.4%	1.4%	1.4%
33									
34	Cumulative Revenue Requirement % Increase	4.3%	6.1%	9.7%	12.2%	0.0%	1.5%	3.0%	4.6%
35									
36									
37	* Corresponding adjustments have also been made to commercial use rates								

Table 1

TERASEN GAS INC.
EXPLANATION OF REVENUE REQUIREMENT DEFICIENCIES
BASE CASE (RESIDENTIAL USE RATE AT 2004 RATE OF 104.7 GJ/YEAR THROUGHOUT)
($ Millions)

Table 2

Line No.	Particulars	Application 2004	2005	2006	2007
	(1)	(2)	(3)	(4)	(5)
1	Volumes/Revenue Related				
2					
3	Lower use rate for rates 1/2/3/23	$13.6	-	-	-
4	Customer growth and industrial revenue changes	(2.0)	($3.7)	($4.2)	($4.8)
5		11.6	(3.7)	(4.2)	(4.8)
6	O & M Related				
7					
8	Higher O&M per formula	10.1	3.3	2.9	3.0
9					
10	Higher Property Tax	(1.8)	1.3	1.2	1.1
11					
12	Higher Depreciation & Amortization	8.2	2.7	7.5	1.1
13		16.5	7.3	11.6	5.2
14					
15	Higher Other Operating Revenue	-	(3.0)	-	-
16					
17	Other Items	(8.9)	0.9	1.8	3.9
18					
19	Total Revenue Deficiency	$19.2	$1.5	$9.2	$4.3

TERASEN GAS INC.
ESTIMATED MARGIN TO COST RATIOS
FOLLOW-UP TO NOVERMBER 21, 2003 ANNUAL REVIEW

Table 3

Line No.	Particulars	Residential Rate 1	Small Commercial Rate 2	Large Commercial Rate 3 / 23	General Firm Service Rate 5 / 25	Firm Large Volume Service Rate 22
	(1)	(2)	(3)	(4)	(5)	(6)
1	**BASE CASE**					
2	2004	94%	107%	124%	126%	127%
3	2005	94%	107%	123%	126%	125%
4	2006	94%	108%	124%	125%	123%
5	2007	94%	107%	123%	125%	122%
6						
7	**HIGH USE RATE CASE**					
8	2004	94%	107%	124%	126%	127%
9	2005	93%	108%	124%	127%	125%
10	2006	93%	108%	124%	126%	123%
11	2007	93%	108%	123%	126%	122%
12						
13	**LOW USE RATE CASE**					
14	2004	94%	107%	124%	126%	127%
15	2005	94%	108%	123%	125%	125%
16	2006	94%	108%	123%	124%	123%
17	2007	94%	108%	123%	124%	122%
18						
19	**LOW USE RATE PHASED IN CASE**					
20	2004	94%	107%	124%	126%	127%
21	2005	94%	108%	123%	126%	125%
22	2006	94%	108%	123%	125%	123%
23	2007	94%	108%	123%	124%	122%

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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December 2, 2003

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

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

Dear Sirs:

RE: Terasen Gas Inc. ("Terasen Gas")
2003 Annual Review – BCUC Order No. G-66-03
November 28 Filing of Additional Information requested in the November 21, 2003 Annual Review Meeting
Revision of Table 3 – Margin to Cost Ratios

Terasen Gas' November 28 submission regarding additional information requested in the November 21, 2003 Annual Review meeting included a table of estimated margin to cost ratios for the various scenarios of residential and commercial use rates and revenue requirement rate changes. Upon further review of the margin to cost ratios an error in the calculations was discovered which mainly affects the firm Rate Schedule 22, 22A and 22B margin to cost ratios. The daily firm demand of one Rate 22 customer was omitted from the calculations and therefore the allocated cost to this group was understated. Making this correction has the effect of reducing the estimated firm Rate 22 margin to cost ratios by 6% to 7%. The other rate groups presented on Table 3 such as the residential and commercial classes are much larger in terms of customer numbers, overall demand and volumes, so the additional costs allocated to Rate 22 do not change the margin to cost ratios of the other classes appreciably. Beyond the correction to the Rate 22 the commentary on margin to cost ratios in the November 28, 2003 filing remains valid.

Please find attached a revised Table 3 for substitution in the November 28, 2003 filing of additional information.

Please accept our apologies for any inconvenience caused by this correction.

Yours truly,

TERASEN GAS INC.

Original signed by Scott Thomson

Scott A. Thomson

Encl.
c. 2003 Annual Review Registered Participants

TERASEN GAS INC.
ESTIMATED MARGIN TO COST RATIOS
FOLLOW-UP TO NOVEMBER 21, 2003 ANNUAL REVIEW

Table 3
(Rev.)

Line No.	Particulars	Residential Rate 1	Small Commercial Rate 2	Large Commercial Rate 3 / 23	General Firm Service Rate 5 / 25	Firm Large Volume Service Rates 22 / 22A / 22B
	(1)	(2)	(3)	(4)	(5)	(6)
1	**BASE CASE**					
2	2004	94%	108%	124%	126%	120%
3	2005	94%	107%	124%	126%	118%
4	2006	94%	108%	124%	125%	116%
5	2007	94%	107%	123%	125%	116%
6						
7	**HIGH USE RATE CASE**					
8	2004	94%	108%	124%	126%	120%
9	2005	93%	108%	124%	127%	119%
10	2006	93%	108%	124%	126%	117%
11	2007	93%	108%	124%	126%	116%
12						
13	**LOW USE RATE CASE**					
14	2004	94%	108%	124%	126%	120%
15	2005	94%	108%	123%	125%	119%
16	2006	94%	108%	123%	124%	117%
17	2007	94%	108%	123%	124%	116%
18						
19	**LOW USE RATE PHASED IN CASE**					
20	2004	94%	108%	124%	126%	120%
21	2005	94%	108%	124%	126%	118%
22	2006	94%	108%	124%	125%	117%
23	2007	94%	108%	123%	124%	116%