Terasen Gas

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

16705 Fraser Highway
Surrey, B.C. V3S 2X7
Tel: (604) 592-7784
Fax: (604) 592-7890
Email: scott.thomson@terasen.com
www.terasengas.com

January 16, 2004

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. Commodity Unbundling and Customer Choice Phase 1 Cost Allocation Application

Terasen Gas Inc. ("Terasen Gas"), the British Columbia Utilities Commission ("Commission"), and other stakeholders have undertaken to implement a Commodity Unbundling Service for Commercial Customers effective November 1, 2004 and to implement a Stable Commodity Rate Residential Service effective January 1, 2005. As part of this ongoing process, Terasen Gas submits, for Commission approval, the enclosed Commodity Unbundling and Customer Choice Phase 1 Cost Allocation Application.

As first outlined in its July 18, 2003 Report on Commodity Unbundling and Customer Choice Phase 1 ("July 18 Report"), and further outlined in the Application dated October 27, 2003 ("October 27 Application"), and in the revisions to that Application dated December 4, 2003 ("December 4, Revised Application"), Terasen Gas requires the approval of proposed cost recovery mechanisms and rates to be effective April 1, 2004 in order to meet the Commodity Unbundling implementation milestones.

In its application, Terasen Gas is seeking Commission approval for the Midstream and Commodity rates for bundled sales Rate Schedules 1, 2, 3, 4, 5, 6, 6A, 7, as well as the two new Commodity Unbundling Rate Schedules 2U and 3U, to be effective April 1, 2004. Terasen Gas is also seeking approval of the mechanism to be used for the review and approval of future changes to the Commodity rates and the Midstream rates, as well as the amortization and disposition of the deferral accounts related to Commodity Unbundling and the Stable Commodity Rate Residential Service. Terasen Gas is also proposing that a Commodity Unbundling Standing Committee of interested parties be formed as part of the regular process to review Midstream rates each year.

In its Application, Terasen Gas is also seeking approval of costs related to two Scope Changes to the Client Services Agreement with CustomerWorks Limited Partnership. In addition two items of contention, the Bad Debt Factor to be applied to marketer charges and the Transaction Fee associated with processing manual Historical Consumption Release requests were raised in the process dealing with the October 27 Application, which Terasen Gas committed to addressing in this Application. Terasen Gas requests approval of a Bad Debt Factor of 0.3% to be effective November 1, 2004 and a Transaction Fee for the Historical Consumption Request set at $30, as set out in Rate Schedule 36.

In order to facilitate a smooth implementation of the new Commodity and Midstream rates, Terasen Gas is requesting that no cost of gas related rate changes occur on April 1, 2004, even if the quarterly flow-through mechanism indicates that a change would be required. Terasen Gas proposes a potential change could be deferred to the next quarterly flow through, or May 1, 2004 if deemed necessary.

Included in this Application is an analysis of operating cost amounts that differ based on certain key assumptions. The primary driver of operating costs for Commodity Unbundling and the Stable Commodity Rate is level of participation by customers and marketers. Terasen Gas wishes to reinforce that the cost levels included are for illustrative purposes only. Actual operating expenses incurred for the programs will vary based on participation and Terasen Gas will be requesting full recovery of those costs consistent with the directive in Commission Letter No. L-25-03, dated June 6, 2003 stating “Terasen Gas shareholders will not be at risk for the costs of implementing and maintaining the service, or for any assets stranded by unbundling.”

It is Terasen Gas' understanding that the next step in the approval process will be a Commission led Workshop on January 26, 2004 that will provide the forum to discuss each of the items being submitted in this Application. Terasen Gas anticipates receiving Commission approval for the above noted items by March 1, 2004 in order to allow sufficient time to implement the new rates into the Customer Information System.

If there are any questions regarding the content of this letter or the enclosed Application related to Commodity Unbundling and Customer Choice Phase I program implementation, please contact Tom Loski at 604-592-7464.

Yours very truly,

TERASEN GAS INC.

Original signed by Scott Thomson

Scott Thomson

/gj
Enclosures

Commodity Unbundling
and
Customer Choice Phase 1
Cost Allocation Application

Terasen Gas Inc.

January 16, 2004

TABLE OF CONTENTS

1. BACKGROUND 1

2. COST RECOVERY OF GAS COSTS FOR COMMODITY UNBUNDLING 2

2.1 COMMODITY COST RECONCILIATION ACCOUNT AND MIDSTREAM COST RECONCILIATION ACCOUNT 3
2.2 COMMODITY AND MIDSTREAM RATES EFFECTIVE APRIL 1, 2004 4
2.3 CCRA AND MCRA REPORTING AND RATE SETTING 6
2.4 COMMODITY AND MIDSTREAM COST RECONCILIATION ACCOUNTS / PORTFOLIO TRANSITION ISSUES / RATE VOLATILITY 6

3. COST RECOVERY OF CAPITAL IMPLEMENTATION COSTS 10

3.1 TREATMENT OF IMPLEMENTATION COSTS 11
3.2 RECOVERY OF IMPLEMENTATION COSTS 12

4. COST RECOVERY OF OPERATING AND MAINTENANCE COSTS 13

4.1 OPERATING AND MAINTENANCE COSTS ESTIMATES 14
4.2 RECOVERY OF OPERATING AND MAINTENANCE COSTS 16
4.3 MARKETER BAD DEBT DEDUCTION 19

5. TERASEN GAS STABLE COMMODITY RATE OFFERING 21

5.1 OVERVIEW OF STABLE COMMODITY RATE RESIDENTIAL SERVICE 21
5.2 CAPITAL IMPLEMENTATION COSTS 21
5.3 ANNUAL OPERATING COSTS 21
5.4 COST RECOVERY 22

6. SCOPE CHANGE FOR COMMERCIAL COMMODITY UNBUNDLING & STABLE RATE OPERATING AGREEMENTS 25

6.1 COMMERCIAL UNBUNDLING AND STABLE RATE 25

7. POST-IMPLEMENTATION REVIEW & NEXT STEPS 29

APPENDIX 1 COST ALLOCATION FROM GCRA TO CCRA / MCRA 31

APPENDIX 2 GAS COST RATE SCHEDULES 32

APPENDIX 3 RATE SCHEDULE 36 APPENDIX "B" 35

APPENDIX 4 NUMERICAL EXAMPLE OF STABLE COMMODITY RATE ACCOUNTING – BASE SCENARIO 36

APPENDIX 5 NUMBERICAL EXAMPLE OF STABLE COMMODITY RATE ACCOUNTING – SCENARIO #1 37

APPENDIX 6 SCHEDULE "F" 38

APPENDIX 7 SCHEDULE "G" 44

1. BACKGROUND

This Application is in part an ongoing process undertaken by Terasen Gas Inc. (“Terasen Gas”), the British Columbia Utilities Commission (“Commission”) and other stakeholders to implement Commodity Unbundling Service for Commercial Customers ("Commodity Unbundling") effective November 1, 2004 and to implement a Stable Commodity Rate Residential Service ("Stable Commodity Rate") effective January 1, 2005.

The Essential Services Model and the business rules for Commodity Unbundling were approved by the Commission as Appendix A to Commission Letter No. L-25-03 dated June 6, 2003. Terasen Gas, in its July 18, 2003 Report on Commodity Unbundling and Customer Choice Phase 1 (“July 18 Report”), outlined an implementation plan for Commodity Unbundling to meet the November 1, 2004 target date. The first significant step in that implementation plan was the need for Tariffs and Agreements, a Code of Conduct for Gas Marketers, Rules for Marketers and a Customer Education Program which were the subject of the Terasen Gas Application dated October 27, 2003 (“October 27 Application”) and in the Terasen Gas Revisions to the October 27 Application, dated December 4, 2003 (“December 4 Revised Application”). These items were approved by the Commission in Order G-90-03, dated January 9, 2004.

The second significant aspect of the implementation plan requiring Commission approval relates to cost allocations and recovery. In its December 4 Revised Application, Terasen Gas indicated that in order to meet its implementation milestones as set out in the July 18 Report, it would submit an application by January 16, 2004. To meet the 2004 implementation milestones, Terasen Gas requires that the approval process for this Application be completed by the end of February, 2004 in order to meet the April 1, 2004 effective date for rate re-design changes, and the subsequent and dependent milestone dates.

In this Application, Terasen Gas is requesting approval of:

a) the assignment of existing Gas Cost Reconciliation Account (“GCRA”) components to either the Commodity function or the Midstream function, as outlined in Section 2 of this Application,

b) the Commodity Cost Recovery Rates for Rate Schedules 1, 2, 3, 4, 5, 6, 6A, 7, 2U and 3U, and a new deferral account, the Commodity Cost Recovery Account (“CCRA”), to be effective April 1, 2004 as outlined in Section 2 of this Application,

c) the Midstream Cost Recovery Rates for Rate Schedules 1, 2, 3, 4, 5, 6, 7, 2U and 3U, and a new deferral account, the Midstream Cost Recovery Account (“MCRA”), to be effective April 1, 2004 as outlined in Section 2 of this Application,

d) the discontinuation of the use of the GCRA deferral account as of March 31, 2004 and the transfer of the balance in that account as at March 31, 2004 to the MCRA , as outlined in Section 2 of this Application,

e) the mechanism used to review the CCRA and MCRA deferral accounts and approve future changes to the commodity rates and the midstream rates, as outlined in Section 2 of this Application,

f) the deferred of any potential Gas Cost flow-through Rate change determined for April 1, 2004 to July 1, 2004 resulting from application of the existing quarterly GCRA review mechanism, as outlined in Section 2 of this Application,

g) transfer of any balance in the CCRA deferral account as at October 31, 2004 to the MCRA deferral account, as outlined in Section 2 of this Application,

h) deferral account treatment and cost recovery methodology, including 3 year amortization period and inclusion of AFUDC, of the program development costs incurred in the implementation of the Commodity Unbundling program, as outlined in Section 3 of this Application,

i) cost recovery of ongoing Operating and Maintenance costs related to providing the Commodity Unbundling program, as outlined in Section 4 of this Application,

j) a Transaction Fee of $30.00 for the Historical Consumption Release service to marketers, to be included in the approved Rate Schedule 36, Appendix B, to be effective April 1, 2004, as outlined in Section 4 of this Application,

k) a Bad Debt Factor of 0.3%, to be effective November 1, 2004, as outlined in Section 4 of this Application,

l) deferral account treatment and cost recovery methodology for the implementation costs and annual operating costs of providing the Stable Commodity Rate Service program, as set out in Section 5 of this Application,

m) the operating costs related to scope changes to the Client Services Agreement with CustomerWorks Limited Partnership for the Commodity Unbundling program and the Stable Commodity Rate program, effective April 1, 2004, as outlined in Section 6 of this Application, and

n) the post-implementation review process as outlined in Section 7 of this Application.

2. COST RECOVERY OF GAS COSTS FOR COMMODITY UNBUNDLING

Terasen Gas purchases gas on behalf of its sales customers and passes these costs through to sales customers without mark-up. Costs are recovered from customers through gas cost recovery rates. As these gas cost recovery rates are based on forecast costs and actual costs invariably differ from forecast costs, the GCRA is used to accumulate the difference between the cost incurred by Terasen Gas to purchase the gas commodity and the revenue collected by Terasen Gas through the gas cost recovery component of rates.

Currently, all gas supply costs related to the Commodity and Midstream functions are captured in the GCRA deferral account and recovered through the Gas Cost Recovery

Charge. The current gas cost recovery mechanism utilizes quarterly reviews of the gas purchase costs to determine if changes to the charges need to be revised.

Under the Essential Services Model, it is necessary to separate the commodity costs from the midstream costs; accordingly, there will be a need for two separate deferral accounts. One will be required to accumulate the commodity related costs and the other to accumulate the midstream related costs. These accounts will herein be referred to as the CCRA and the MCRA. The July 18 Report provided additional detail surrounding the new CCRA and MCRA, and further discussions within this Application are consistent with the information provided in that report.

2.1 Commodity Cost Reconciliation Account and Midstream Cost Reconciliation Account

To support the November 1, 2004 start date for the Commodity Unbundling program and to facilitate the separation of the commodity and midstream costs, the CCRA and MCRA will be established effective April 1, 2004. Any outstanding GCRA imbalance as at April 1, 2004 will be transferred to the MCRA and the CCRA will have a zero balance at that date.

The purpose of the CCRA is to accumulate any commodity price variances so that these may be assigned to the appropriate customers. The CCRA will capture the costs incurred by Terasen Gas to purchase its portion of the baseload gas requirements and the revenue collected by Terasen Gas through gas commodity rates. Terasen Gas, in its role as Commodity provider ("Terasen Gas Commodity"), will be supplying baseload gas, on a 100% load factor basis, as per the forecast annual supply requirements. Terasen Gas' cost for this baseload gas will be charged to the CCRA, and the revenue collected by Terasen Gas for the commodity portion of the applicable customer sales will be credited to the CCRA. On an annual basis, there will be a difference between the baseload supply requirement and the actual consumed quantity. This volume-related variance is the responsibility of Terasen Gas in its role as Midstream services provider ("Terasen Gas Midstream") and as such will be transferred to the MCRA. Commodity price-related variances will be collected in the CCRA and will be taken into account when determining commodity rate changes. Costs collected in the CCRA will not be incremental to the costs that customers are paying today, as these variances currently accumulate in the GCRA. Customers remaining on the Terasen Gas standard sales rate schedules will continue to pay the Terasen Gas commodity rate. Eligible commercial customers choosing to obtain marketer provided commodity will pay the marketer set commodity rate instead of the Terasen Gas commodity rate.

As marketers begin to participate in the Commodity Unbundling program, portions of the baseload gas requirements will be allocated to them. Similar to Terasen Gas Commodity, the marketers will be supplying baseload gas, on a 100% load factor basis, as per the forecast annual supply requirements for their customer groups. The marketer supplied commodity will be managed through separate Marketer Clearing Accounts (“MCA”) and will not contribute to the costs and volumes accounted for within the CCRA. On an annual basis, there will be a difference between the baseload supply requirement and the actual consumed quantity. This volume-related variance is the responsibility of the Midstream and will be transferred from the MCA to the MCRA. As the Commodity provided by the Marketer is purchased by Terasen Gas at the same price at which it is sold, there should be no price-related variances within the MCA.

The MCRA is designed to capture all the costs associated with the Midstream function and the revenue collected by Terasen Gas through midstream rates. The commodity providers, both Terasen Gas Commodity and marketers, will deliver baseload volumes, including any fuel in-kind, at the three receipt points. Terasen Gas Midstream will then deliver gas to gate stations to meet daily firm customer demands. The Midstream will use the pipeline, storage resources, spot and peaking purchases, and sale activities as approved in the Annual Contracting Plan to manage load variability. The MCRA will collect any resultant cost variances, including any volume-related variances due to differences between the forecast and actual consumption. All customers who are currently on commodity sales rate schedules will continue to pay for the midstream resources, the same as they do today. For the existing transportation rate schedules, there will be no impact as the result of these changes.

2.2 Commodity and Midstream Rates Effective April 1, 2004

The Commission in its Letter No. L-25-03 dated June 6, 2003, confirmed that the current allocation methodology utilized with the GCRA is appropriate for the CCRA and MCRA. Appendix 1 contains a summary of the allocation methodology used for the costs and recoveries associated with the GCRA and demonstrates that a consistent methodology will be applied to the costs and recoveries associated with the CCRA and MCRA. In general, costs are broken down into fixed versus variable, with the fixed costs allocated to the rate schedules based on that rate class load factor and the variable costs allocated based on consumption.

As part of this application, Terasen Gas is requesting approval of the new Commodity and Midstream rates, effective April 1, 2004, as summarized in the following table. The rates effective April 1, 2004 only split the existing bundled commodity rate into the commodity and midstream components. There will be no change in the total rates paid by customers as a result of this rate application. However, there is the possibility that pricing changes in the natural gas market in the first quarter of 2004 may necessitate a gas cost rate adjustment on April 1, 2004 based on the gas cost flow-through mechanism. Based on preliminary analysis, as of the date of this Application, Terasen Gas does not anticipate a need for a rate adjustment. Terasen Gas will be bringing forward analysis at the upcoming January 26 workshop for review and discussion on this issue. Furthermore, Terasen Gas is requesting that no rate change be made in April 1, 2004 to facilitate a smooth transition to the new rates structure. This is described in more detail in Section 2.4.3.1.

Terasen Gas Inc. - Gas Cost Recovery Charges By Service Area By Rate Schedule

Lower Mainland Service Area							
	Rate Schedule						
Description	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6	Rate 7
Commodity Rate	**$ 6.020**	**$ 6.048**	**$ 5.960**	**$ 5.879**	**$ 5.879**	**$ 5.780**	**$ 5.879**
Midstream Rate	**1.147**	**1.204**	**1.032**	**0.872**	**0.872**	**0.680**	**0.872**
Total Bundled Rate	**$ 7.167**	**$ 7.252**	**$ 6.992**	**$ 6.751**	**$ 6.751**	**$ 6.460**	**$ 6.751**
Current Bundled Commodity Rate	$ 7.167	$ 7.252	$ 6.992	$ 6.751	$ 6.751	$ 6.460	$ 6.751

Note: The Rate 2U and 3U Midstream Rates equal the Rate 2 and 3 Midstream Rates, respectively.

Inland Service Area							
	Rate Schedule						
Description	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6	Rate 7
Commodity Rate	**$ 6.020**	**$ 6.048**	**$ 5.960**	**$ 5.879**	**$ 5.879**	**$ 5.780**	**$ 5.879**
Midstream Rate	**1.040**	**1.093**	**0.935**	**0.788**	**0.788**	**0.615**	**0.788**
Total Bundled Rate	**$ 7.060**	**$ 7.141**	**$ 6.895**	**$ 6.667**	**$ 6.667**	**$ 6.395**	**$ 6.667**
Current Bundled Commodity Rate	$ 7.060	$ 7.141	$ 6.895	$ 6.667	$ 6.667	$ 6.395	$ 6.667

Note: The Rate 2U and 3U Midstream Rates equal the Rate 2 and 3 Midstream Rates, respectively.

Columbia Service Area							
	Rate Schedule						
Description	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6	Rate 7
Commodity Rate	**$ 6.020**	**$ 6.048**	**$ 5.960**	**$ 5.879**	**$ 5.879**	**$ 5.780**	**$ 5.879**
Midstream Rate	**1.176**	**1.231**	**1.067**	**0.915**	**0.915**	**0.615**	**0.915**
Total Bundled Rate	**$ 7.196**	**$ 7.279**	**$ 7.027**	**$ 6.794**	**$ 6.794**	**$ 6.395**	**$ 6.794**
Current Bundled Commodity Rate	$ 7.196	$ 7.279	$ 7.027	$ 6.794	$ 6.794	$ 6.395	$ 6.794

Note: The Rate 2U and 3U Midstream Rates equal the Rate 2 and 3 Midstream Rates, respectively.

Appendix 2 contains the back-up sheets showing the Commodity and Midstream Recovery Rates.

2.2.1 Commodity Unbundling Rate Schedules (Rate Schedules 2U and 3U)

Rate Schedule 2U applies to Commodity Unbundling service for small commercial customers and Rate Schedule 3U applies for large commercial customers. In this Application, Terasen Gas is seeking approval of the specific charges, effective April 1, 2004, the revised Table of Charges for these Rate Schedules will be submitted for approval after the rates are approved.

2.2.2 Revisions to Remaining Bundled Sales Rate Schedules

The customer bill for Rate Schedule 2 (small commercial) customers and Rate Schedule 3 (large commercial) customers will display the Midstream Cost Recovery Charge and Commodity Gas Recovery Charge separately. In this Application, Terasen Gas is seeking approval of the specific charges, effective April 1, 2004, the revised Table of Charges for these Rate Schedules will be submitted for approval after the rates are approved.

The customer bill will not display the Midstream Cost Recovery Charge and Commodity Gas Recovery Charge separately for bundled sales customers other than commercial customers. In this Application, Terasen Gas is seeking approval of the specific charges, effective April 1, 2004, the revised Table of Charges for these Rate Schedules will be submitted for approval after the rates have been approved.

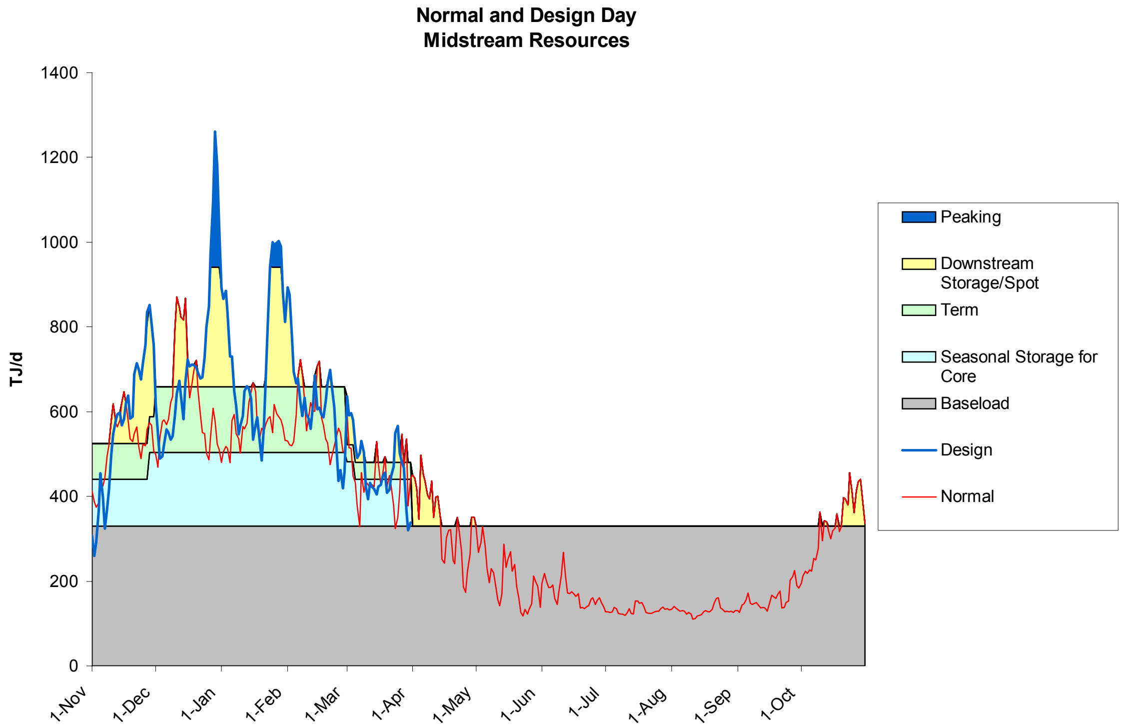
2.3 CCRA and MCRA Reporting and Rate Setting

Terasen Gas proposes that the gas cost recovery review mechanism and process currently in place should continue to be used for the midstream and commodity deferral accounts. The commodity cost recovery rate for the standard rate schedules will continue to be reviewed and adjusted on a quarterly basis. For midstream costs however, an annual review and adjustment process is more appropriate due to the annual load balancing. An annual adjustment process would provide stability to the midstream component of gas costs for customers. In addition, it would synchronize with the annual delivery margin adjustment process on January 1st of each year, helping to streamline communications with customers regarding rate adjustments. Furthermore, an annual review process for midstream resources would be consistent in timing with the current annual process for developing the Annual Contracting plan.

2.4 Commodity and Midstream Cost Reconciliation Accounts / Portfolio Transition Issues / Rate Volatility

The GCRA is designed to capture and account for all costs and recoveries associated with the gas portfolio for all Terasen Gas firm sales customers. With unbundling effective April 1, 2004, the GCRA will be divided into a Commodity (CCRA) account designated as the default baseload supply and for all of Terasen Gas' sales customers, and a Midstream (MCRA) account comprised of the remaining resources required to meet design peak day. While the baseload commodity will be removed from the rest of the gas portfolio, associated guiding principles and contracting objectives of both accounts will remain unchanged. Terasen Gas will still be required to follow the mandatory regulatory approval process including developing Commodity and Midstream annual contracting plans, seeking Commission approval and implementing these plans within the specified approved guidelines.

The following chart illustrates the Midstream resources and baseload volume deliveries used to meet forecasted normal and design load requirements. Given that the Annual Contracting Plan for 2004 has yet to be approved, the stack of resources depicted in the chart is for illustration purposes only.



2.4.1 Midstream Planning

Terasen Gas Midstream's primary responsibility will be to develop a portfolio of pipeline, storage and commodity contracts aimed at satisfying the primary objectives of the Annual Contracting Plan that include:

- Ensure secure and reliable natural gas deliveries to meet Core customer design peak day.
- Optimize the costs associated with providing load balancing and transport services for all customers.
- Portfolio asset mix and price diversity which incorporates contracting flexibility for both short and longer term.
- Provide resources above baseload supply.

Terasen Gas Midstream group will continue to, subject to satisfying the objectives identified above, identify and evaluate the resources available to meet Lower Mainland and/or Interior loads by examining three key characteristics.

- Supply availability. Since the Interior and Lower Mainland have differing resource availabilities, one must account for any physical limitations or access to Duke, Northwest Pipeline (NPC) and Alberta sources along with what the market has to offer in any given year.

- Cost. Cost not only includes the estimated forecasted price but also any related physical market premiums or resale costs.
- Associated risks of a resource or supply source. Price volatility and liquidity make up the primary associated risks and are key determinants in limiting daily exposure at illiquid trading hubs during the winter months.

Baseload commodity providers including Terasen Gas Commodity will deliver baseload volumes at three receipts points plus fuel in-kind. Terasen Gas Midstream will develop the percentage of baseload deliveries at each of the locations; Station 2, Alberta, and Huntingdon, based on the portfolio resource mix in any given year.

Terasen Gas Midstream will use the pipeline, storage resources, spot and peaking purchases, and sale activities as approved in the Annual Contracting Plan to manage load variability and resultant cost variances.

2.4.1.1 Key MCRA Cost Drivers

The MCRA is made up of the key cost drivers and variances that were outlined in detail in the July 18, 2003 report. These cost variances have been summarized into six distinct groups:

1. Fixed Charges – includes pipeline and storage demand charges, and administrative charges.
2. Term/Peaking – includes the required term, spot and peaking gas purchases.
3. Storage Commodity – includes the summer injected commodity cost.
4. Other – includes all other variable charges such as fuel, company own use fuel, unaccounted for gas, etc.
5. Resale – includes the recoveries from the resale of excess supply.
6. Asset Mitigation – includes all mitigation of pipe and storage assets.

The cost components above take into account weather-related demand and cost variances for firm customers. In addition, Terasen Gas also manages marketer group allocation demand and any resultant cost variances occurring in the lag time between marketer group re-allocation timelines. This re-allocation variance is not expected to be significant and will be managed using the same resources described above.

Weather demand and pricing volatility have the largest impact on the MCRA's overall costs in any given year. Given that cost variability is likely to occur in order to avoid accumulating large deferral accounts Terasen Gas is seeking approval for the MCRA rate setting process to be evaluated and adjusted yearly without the use of threshold percentages. Terasen Gas is proposing a consultative process whereby a standing committee would be set up to meet on an annual basis and review the yearly Midstream plan.

2.4.2 CCRA Account

Terasen Gas Commodity will be the default commodity supplier of the baseload supply requirements with the same primary objectives as it has today.

- Managing impacts on customer rates due to commodity price volatility.
- Optimizing and diversifying gas pricing for term purchases.
- Focusing price risk management activities on remaining competitive with other energy sources, primarily electricity.

Baseload supply requirements have been defined as the core annual normalized load that will be supplied by both Terasen Gas Commodity and marketers. Terasen Gas will still be required to follow the mandatory regulatory approval process including developing a Commodity annual contracting plan, seeking Commission approval for and implementing the plan within the specified approved guidelines. Terasen Gas is also seeking approval to review the CCRA rate on a quarterly basis and continue to apply the same rate mechanism that currently has been set out by Commission.

2.4.3 Transitional Issues

Terasen Gas recognizes there are a number of issues related to implementing the Commodity Unbundling program, for the April 1, 2004 through October 31, 2004 timeframe, that it considers as transitional in nature.

2.4.3.1 Freezing Rates for April 1, 2004

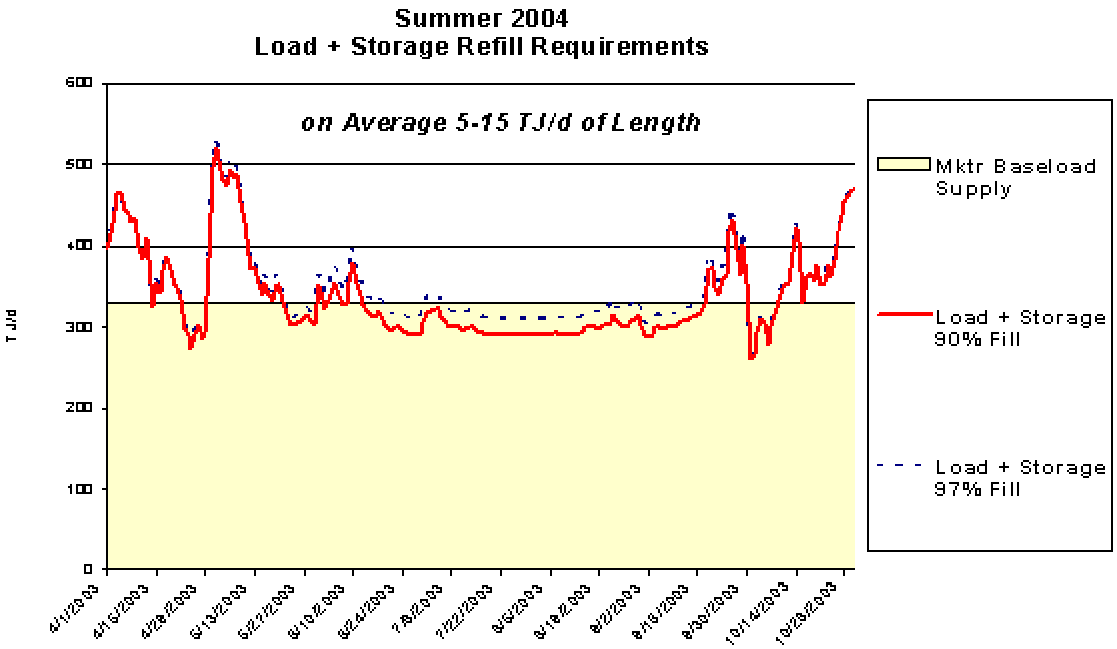
As mentioned under Section 2.2, Terasen Gas requests approval to defer any potential Gas Cost flow-through rate change determined for April 1, 2004 to July 1, 2004, resulting from application of the existing quarterly GCRA review mechanism. This will provide stability to Commercial customers and enhance the customer education effects. It will also facilitate a smooth transition to the new rate structure for implementation in the customer information system. Although at this point in time Terasen Gas does not expect there to be rate change resulting form the mechanism, it will provide additional information at the January 26, 2004 Workshop. In the event that it is determined that deferring a potential rate change to July 1, 2004, Terasen Gas will consider making a change May 1, 2004.

2.4.3.2 CCRA Build from April 1, 2004 to October 31, 2004

Terasen Gas requests approval to transfer any CCRA balance as at October 31, 2004 over to the MCRA effective November 1, 2004. Eliminating any CCRA balance as at October 31, 2004 will provide for a level playing field for marketers to enter the marketplace and also eliminate the need for exit fees for those customers that exercise their choice to switch to a gas marketer. Terasen Gas anticipates that no exit fee will be required in the future using the existing commodity rate setting process as it presently provides for a timely flow-thru of commodity gas costs incorporating price changes in the marketplace.

2.4.3.3 Gas Supply portfolio issues April 1st to October 31st

Transitioning the gas portfolio for April 2004, given unbundling commences in the middle of the gas contracting year, does not impact Terasen Gas' existing implementation plans. Receipt of the levelized summer supply by Terasen Gas Midstream will be injected into storage, used for core load requirements and/or optimized as synthetic storage for winter requirements. The chart below illustrates the core load and estimated summer injection profile compared to the levelized summer supply under unbundling. The estimated 5-15 TJ/d of excess supply will be optimized either through resale or used to create a synthetic winter storage arrangement by selling off excess summer supply and buying winter supply.



3. COST RECOVERY OF CAPITAL IMPLEMENTATION COSTS

The Commission in its Letter No. L-25-03, provided direction on the allocation of costs to the utility commercial customers who have the opportunity to participate in the unbundling program and to the marketers involved. Specifically the Letter stated "The implementation and maintenance costs will be recovered from customers in those rate classes that are eligible for the service. Annual operating costs (fixed and transactional related costs) should be recovered, to the extent possible, from marketers. Terasen Gas shareholders will not be at risk for the costs of implementing and maintaining the service, or for any assets stranded by unbundling."

Although the rider amounts are not specifically being requested in this Application, the total implementation costs approved in Commission Order No. G-57-03 dated September 15, 2003 totals $7.15 million, have been used in the analysis to show the impact to rates.

3.1 Treatment of Implementation Costs

The following table summarizes the approved implementation costs.

Implementation Costs	
Capital Expenditures	
Computer Hardware	$100,000
Computer Software	$6,650,000
Education & Business Rule/Tariff Development	$400,000
Total Capital Expenditures	$7,150,000

Further, Terasen Gas has conducted analysis to show the results of treating the capital implementation costs under both the Plant in Service and the Deferred Account methodologies. Under the Plant in Service methodology, the Computer Hardware and Software are treated as additions to gas plant in service and the respective impact on the cost of service is calculated. Under the Deferred Account methodology, the Computer Hardware and Software are charged to a deferral account and cost is amortized over three years. Under both methodologies, the Customer Education and Business Rule / Tariff Development costs are charged to a deferral account and the after tax cost is amortized over three years. The following table summarizes the differences in the accounting treatment between charging the Computer Hardware and Software costs to gas plant in service or to a deferred charge account.

Plant in Service versus Deferred Account Method	
Plant in Service	
Computer Hardware	$100,000
Depreciation Rate (1 year lag)	20% - 5 Years
Computer Software	$6,650,000
Depreciation Rate (1 year lag)	12.5% - 8 Years
CIAOC: Tax Savings	Direct Cost x Tax Rate
Amortization Rate	12.5% - 8 Years
Cost of Service Present Value: 9 Yrs	$6,570,550
Levelized Average Annual Cost of Service: 9 Years	$1,032,450
Deferred Account	
Computer Hardware	$100,000
Amortization (no lag)	3 Years
Computer Software	$6,650,000
Amortization (no lag)	3 Years
Cost of Service Present Value: 3 Years	$6,678,420
Levelized Average Annual Cost of Service: 3 Years	$2,570,680

Discount Rate is 7.555% from the 2004 Annual Review – Return on Rate Base.

The present value of the cost of service is higher under the Deferred Charge treatment over the Gas Plant in Service treatment by approximately $110,000 with the levelized average annual cost of service also significantly higher under the Deferred Charge treatment of costs. The significant difference in the levelized average annual cost of service is due to the time difference in which the costs are recovered; nine years for Gas Plant in Service versus three years for Deferred Charge treatment.

Terasen Gas is seeking approval for the Deferred Charge methodology. The useful life of the Commercial Unbundling program assets is considered to be three years. Therefore treating the costs as Deferred Charges with a three year amortization provides a better matching of cost recovery than treating the costs as Gas Plant in Service which requires a nine year recovery period. Furthermore, tracking of costs in a deferral account would be administratively easier to accomplish than having to track the costs separately in the Gas Plant in Service accounting ledger for assigning cost responsibility to the commercial customers.

Although the rider amounts are not specifically being requested in this Application, the latest estimates of the implementation costs and the analysis showing the impact to rates are discussed within the next section. The examples provided are meant to be illustrative of the best estimates available at this time. Terasen Gas seeks approval to collect costs related to the implementation of the Commercial Commodity Unbundling program in a deferral account that will attract AFUDC, and to amortize these cost over a three year period and recover these costs from all commercial customers eligible for the program via a rate rider. Terasen Gas will submit an application in the fourth quarter of each year to set the rider that will be effective January 1st of the following year.

3.2 Recovery of Implementation Costs

Terasen Gas proposes the use of a rider to recover the implementation costs. By having the implementation costs attract AFUDC and the recovery of the amortization of the implementation costs by a rider, the utility's rate base and cost of service is unaffected by the Commercial Unbundling program.

The following table summarizes the estimated required recovery for the implementation costs under the Deferred Account method.

Deferred Account			
	2005	**2006**	**2007**
Amortization of Implementation Costs	$2,336,000	$2,336,000	$2,336,000
Total Cost of Service	$2,029,000	$2,134,000	$3,668,000
Present Value of Annual Cost of Service	$6,678,420		
Levelized Annual Cost of Service (first 3 years)	$2,570,680		
Average Annual Cost of Service (first 3 years)	$2,610,333		
Average Number of Customers	76,286	76,286	76,286
Annual Volumes (TJ)	39,758	39,758	39,758

Average Cost / Customer / Year	$26.60	$27.97	$48.08
Average Cost / GJ	$0.051	$0.054	$0.092
3 – Year Average Cost / Customer / Year	$34.21		
3 – Year Average Cost / GJ	$0.065		

(Average # of customers and volumes exclude Revelstoke and Fort Nelson customers).

Based on this scenario and a three year recovery of the implementation costs, the total impact on commercial customers is expected to be, on average, less than $35 per year per customer, assuming a fixed fee recovery. If the costs were to be recovered on a variable per GJ basis, the cost would be approximately $0.065 per GJ.

The July 18th Report included estimates of the implementation costs related to the Commercial Commodity Unbundling program and the impact on customer rates. The assumptions and estimates in this section reflect the most current information available and will therefore vary slightly from the information previously presented.

Terasen Gas anticipates that the customers most likely to participate in the unbundling program will be the larger volume commercial customers who are most likely to benefit from arranging commodity requirements supplied by a marketer. Under this assumption, Terasen Gas suggests it would be more equitable to charge a variable rate rider to recover the deferral costs as larger volume customers would contribute more to the recovery than smaller volume users. Terasen Gas proposes that the costs be recovered over a three-year period commencing January 2005, by way of a per GJ rider for all commercial customers eligible for the Commodity Unbundling, excluding those being served under Rate Schedule 23.

Terasen Gas is seeking approval in this Application to collect costs related to the implementation of the Commercial Commodity Unbundling program in a deferral account that will attract AFUDC, and amortize and recover these costs from all commercial customers eligible for the program via a rate rider. Terasen Gas will submit an application in the fourth quarter of 2004 to set the rider that will be effective January 1, 2005, and reset the rider each following year during the three year amortization period.

4. COST RECOVERY OF OPERATING AND MAINTENANCE COSTS

Although the rider amounts are not specifically being requested in this Application, the latest estimates of the operating and maintenance costs and the analysis showing the impact to rates are discussed within this section. The cost and recovery examples provided are meant to be illustrative of the best estimates available at this time. Terasen Gas seeks approval to collect all operating and maintenance costs and marketer transaction fee recoveries in a deferral account, and to recover the deferral account balances from all commercial customers eligible for the Commercial Commodity Unbundling program, through the use of a rate rider.

4.1 Operating and Maintenance Costs Estimates

Consistent with the approach adopted within the July 18th Report, the operating and maintenance costs have been developed by each of the three functional teams on the project (Gas Supply, Forecasting, and Customer Care) utilizing a common approach to create a bottom-up estimate. Each team defined the work directly related to the processes and business rules within their respective areas, and determined the effect of activity levels on the variable costs. Operating costs were estimated for the various units of work identified using estimated labour rates and Information Technology (IT) support costs. The operating costs are both fixed and variable to some degree and, in general, the Customer Care costs were found to vary more with changes in activity levels than the Forecasting and Gas Supply costs due to the manual nature of the processes. The basis for this variability is described in Section 6. For the purposes of this analysis, anticipated IT sustainment costs described under Section 6.1.2.1 have been included. Terasen Gas is currently in negotiations with its customer care service provider with respect to the operating costs estimates and, as such, these estimates are subject to change.

Maintenance costs are primarily hardware related and are not expected to vary by the number customers enrolled or the number of groups.

Two scenarios representing a low case and a high case are presented.

The following table summarizes key assumptions and the estimated operating and maintenance expenses for calendar 2004 through 2006 for the low case example, entitled Scenario #1.

Scenario #1 – O&M Costs			
	2004	**2005**	**2006**
Key Assumptions			
Cumulative No. of Marketers	2	4	4
Additional No. of Marketer Groups per Marketer	2	4	4
No. of Enrolment periods	1	3	4
Annual number of enrolments received	10,000	10,000	10,000
Rejected enrolments (15% in 2004, 10% thereafter)	1,500	1,000	1,000
Customer Finalizations at 10% per year	850	1,665	2,399
Number of enrolled customers at year end	7,650	14,985	21,586
Operating Expenses			
Forecasting, including IT Support	$2,500	$6,000	$6,000
Gas Supply, including IT Support	$10,000	$12,000	$12,000
Customer Care (CustomerWorks), including IT Support	$120,014	$178,204	$178,204
Total Operating Costs	$132,514	$196,204	$196,204
Maintenance Costs			
Forecasting	$12,000	$12,000	$12,000
Gas Supply	$12,000	$12,000	$12,000

Total Maintenance Costs	$24,000	$24,000	$24,000
Total Operating and Maintenance Costs	$156,514	$220,204	$220,204

Note - based on calendar years

A second set of assumptions, which could be considered a more aggressive scenario in terms of customer enrolment is included to represent a high case example and is entitled Scenario #2.

Scenario #2 – O&M Costs			
	2004	**2005**	**2006**
Key Assumptions			
Cumulative No. of Marketers	3	6	8
Additional No. of Marketer Groups per Marketer	2	6	8
No. of Enrollment periods	1	3	4
Annual number of enrolments received	20,000	20,000	20,000
Rejected enrolments (15% in 2004, 10% thereafter)	3,000	2,000	2,000
Customer Finalizations at 10% per year	1,700	3,330	4,797
Number of enrolled customers at year end	15,300	29,970	43,173
Operating Expenses			
Forecasting, including IT Support	$2,500	$6,000	$6,000
Gas Supply, including IT Support	$10,000	$12,000	$12,000
Customer Care (CustomerWorks), including IT Support	$171,298	$251,244	$303,520
Total Operating Costs	$183,798	$269,244	$321,520
Maintenance Costs			
Forecasting	$12,000	$12,000	$12,000
Gas Supply	$12,000	$12,000	$12,000
Total Maintenance Costs	$24,000	$24,000	$24,000
Total Operating and Maintenance Costs	$207,798	$293,244	$345,520

Note - based on calendar years

As evidenced by the two preceding scenarios, the operating expenses can vary significantly based on the success of the program and the resulting participation levels. Customer Care related cost increase proportionately with the level of customer participation. Gas Supply and Forecasting costs do not change significantly with the level of customer participation. Even with an aggressive set of assumptions resulting in more than half the commercial customers selecting Commodity Unbundling, the total operating and maintenance costs are still estimated to be less than $0.4 million. If participation in the program is less than the scenarios depicted herein, then it would follow that customer related operating costs would be lower.

4.2 Recovery of Operating and Maintenance Costs

As directed in Commission Letter No. L-25-03 operating costs, to the extent possible, are to be recovered from marketers. Any operating costs not recovered from marketers will be accumulated in a deferral account and are expected to be recovered from all commercial customers who have access to the program, through the use of a rate rider.

4.2.1 Consumption Release Service

With the Commission's recent approval of the consumption release service pursuant to Order Number G-90-03 where Terasen Gas will provide customer usage information to marketers prior to customer enrolment provided that the customer has signed a "Release of Information" form, Terasen Gas hereby requests approval of a transaction fee to recover the costs of providing the service.

Terasen Gas is proposing to implement a "manual" solution for the provision of historical consumption data. This manual solution will require a release and consent form for each premise to be signed by the customer and faxed to Terasen Gas. Accenture Business Services for Utilities, Terasen Gas' outsource provider for call center related activities, would log the receipt of the consent form for tracking and audit purposes, and locate and verify the appropriate premise on the Energy system. The historical information would be printed and faxed to the marketer. The manual solution provides an immediate option to meet the needs of the marketers with little incremental implementation effort and, should demand fail to materialize, this service can be easily discontinued with little cost.

The cost to implement the "manual" solution is estimated to be between 15 to 20 workdays with operating costs of $30 per information request for each premise. Terasen Gas requests approval for a transaction fee in the amount of $30 per information request for each premise supplied to a marketer which will serve to recover the operating costs of $30 per information request for each premise incurred by Terasen Gas to provide the service.

As with the other operating costs and marketer recoveries related to the Commercial Unbundling program, Terasen Gas requests deferral account treatment for the costs and marketer recoveries associated with the consumption release service. Infrequent use of this service will result in insufficient transaction fees to cover the incremental costs of the service. Terasen Gas agrees to provide a report to the Commission by October 31, 2004 to determine if this manual consumption release service should continue or whether marketers are satisfied with the Terasen Gas Account Online Service.

4.2.2 Marketer Recoveries

Terasen Gas has received approval to charge two Transaction Fees outlined in Rate Schedule 36 which was recently approved by the BCUC Order G-90-03 in order to recover certain operating costs directly from marketers. In this Application, Terasen Gas is now requesting approval for setting the amount of each Transaction fee. These Transaction Fees would be charged on a monthly basis to marketers by netting the charges against the remittances made to marketers each month.

The first Transaction Fee of $0.40 per month would be charged to marketers for each bill sent to customers in the marketers groups. The second Transaction Fee of $150 per month would be charged to marketers for each active marketer group to offset costs related to the manual set-up of rates within the Energy system.

Also, as discussed in Section 4.2.1, Terasen Gas is requesting approval for a Transaction Fee related to the provision of historical consumption data. The estimated costs and recoveries associated with this service have been included in calculating the net operating and maintenance costs.

The following table summarizes key assumptions and the estimated Transaction Fee recoveries for calendar 2004 through 2006 for the low case example, entitled Scenario # 1.

Scenario # 1 – Marketer Recoveries			
	2004	**2005**	**2006**
Key Assumptions			
Cumulative No. of Marketers	2	4	4
Additional No. of Marketer Groups per Marketer	2	4	4
No. of Enrolment periods	1	3	4
Annual number of enrolments received	10,000	10,000	10,000
Rejected enrolments (15% in 2004, 10% thereafter)	1,500	1,000	1,000
Customer Finalizations at 10% per year	850	1,665	2,399
Number of enrolled customers at year end	7,650	14,985	21,586
Average annual number of customers	1,275	11,318	18,286
Cumulative number of groups at year end	4	20	36
Average annual number of groups	0.67	12	28
No. of Historical Gas Consumption Requests	100	100	100
Transaction Fee / Customer / Month	$0.40	$0.40	$0.40
Transaction Fee / Group / Month	$150	$150	$150
Transaction Fee / Historical Consumption / Request	$30	$30	$30
Customer-related Transaction Fee Recovery	$6,120	$54,326	$87,773
Group-related Transaction Fee Recovery	$1,200	$21,600	$50,400
Historical Consumption Transaction Fee Recovery	$3,000	$3,000	$3,000
Total Transaction Fee Recoveries	$10,320	$78,926	$141,173

Note - based on calendar years

The following table summarizes key assumptions and the estimated Transaction Fee recoveries for calendar 2004 through 2006 for a more aggressive scenario and represents a high case example, entitled Scenario # 2.

Scenario # 2 – Marketer Recoveries			
	2004	**2005**	**2006**

Key Assumptions			
Cumulative No. of Marketers	3	6	8
Additional No. of Marketer Groups per Marketer	2	6	8
No. of Enrollment periods	1	3	4
Annual number of enrolments received	20,000	20,000	20,000
Rejected enrolments (15% in 2004, 10% thereafter)	3,000	2,000	2,000
Customer Finalizations at 10% per year	1,700	3,330	4,797
Number of enrolled customers at year end	15,300	29,970	43,173
Average annual number of customers	2,550	22,635	36,572
Cumulative number of groups at year end	6	42	106
Average annual number of groups	0.67	24	74
No. of Historical Gas Consumption Requests	500	500	500
Transactional Fee / Customer / Month	$0.40	$0.40	$0.40
Transactional Fee / Group / Month	$150	$150	$150
Transaction Fee / Historical Consumption / Request	$30	$30	$30
Customer-related Transaction Fee Recovery	$12,240	$108,648	$175,543
Group-related Transaction Fee Recovery	$1,200	$43,200	$133,200
Historical Consumption Transaction Fee Recovery	$15,000	$15,000	$15,000
Total Transaction Fee Recoveries	$28,440	$166,848	$323,743

Note - based on calendar years

4.2.3 Customer Recoveries

Terasen Gas proposes that the operating and maintenance costs, including the marketer recoveries, be accumulated in a deferral account and that, at the end of each calendar year, these costs would be charged to all eligible Rate Schedule 2 and 3 customers via a rider, effective January 1 of each year.

The following table summarizes the estimated required recovery and the amount of the rider for each of the years 2005 through 2007 under the low case example, entitled Scenario # 1.

Scenario # 1 – Customer Recoveries			
	2005	**2006**	**2007**
Net O&M Balance for Recovery from Customers	$146,194	$141,278	$79,031
Average Number of Customers	76,286	76,286	76,286
Annual Volumes (TJ)	39,758	39,758	39,758
Average Cost / Customer / Month	$0.16	$0.15	$0.09
Average Cost / GJ	$0.004	$0.004	$0.002
3 – Year Average Cost / Customer / Month	$0.13		
3 – Year Average Cost / GJ	$0.003		

(Average # of customers and volumes exclude Revelstoke and Fort Nelson customers).

The following table summarizes the estimated required recovery and the amount of the rider for each of the years 2005 through 2007 under the high case example, entitled Scenario # 2.

Scenario # 2 – Customer Recoveries			
	2005	**2006**	**2007**
Net O&M Balance for Recovery from Customers	$179,358	$126,396	$21,777
Average Number of Customers	76,286	76,286	76,286
Annual Volumes (TJ)	39,758	39,758	39,758
Average Cost / Customer / Month	$0.20	$0.14	$0.02
Average Cost / GJ	$0.004	$0.003	$0.001
3 – Year Average Cost / Customer / Month	$0.12		
3 – Year Average Cost / GJ	$0.003		

(Average # of customers and volumes exclude Revelstoke and Fort Nelson customers).

Based on an annual recovery of the operating and maintenance costs, the total impact on commercial customers is expected to be, on average, less than $2.00 per year per customer, assuming a fixed fee recovery. If the costs were to be recovered on a variable per GJ basis, the cost would be approximately $0.003 per GJ.

The July 18th Report included estimates of the operating and maintenance costs related to the Commercial Commodity Unbundling program and the impact on customer rates. The assumptions and estimates in this section reflect the most current information available.

4.3 Marketer Bad Debt Deduction

In Terasen Gas' December 4 Revisions to the October 27, 2003 Application filing, Terasen Gas outlined it's position that charging marketers a bad debt deduction on their sales to customers is appropriate as the bad debt incurred relates directly to the marketers' customers. Terasen Gas proposed that a portion of the proceeds from the marketer bad debt deduction should be allocated back to Rate Schedule 2 and 3 customers to offset some of the operating costs of the unbundling program. As it was a contentious issue, Terasen Gas indicated that it would continue to evaluate and analyze the issue and provide further comments on the subject in this Application.

Terasen Gas researched other jurisdictions that have progressed further down the path of unbundling to determine what they have done in regards to the issue. The table below summarizes the results of the research efforts and also presents for comparative purposes each stakeholder's position on the marketer bad debt deduction issue.

	British Columbia				Other Jurisdictions		
FACTORS	Premstar	Direct Energy	CEG Energy	Terasen Gas	Georgia	Alberta	Ontario
Marketer bills	No	No	No	No	Yes	Yes	No
Marketer pays bad debts	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Bad debt methodology	Customer specific	Aggregate %	Fixed %	Deferral Accounting ~ 0.3%	Determined by Marketer	Determined by Marketer	Utility

"Early" stages of unbundling "Advanced" stages of unbundling

In the jurisdictions of Georgia and Alberta, billing of customers is performed by the marketer instead of the utility. Marketers are responsible for the collection of customers' bills including the management of bad debts. In Ontario, the utilities Enbridge Gas Distribution Inc and Union Gas Limited ("Union Gas") continue to be responsible for the billing function. For Union Gas, a bad debt allowance is recovered from the marketers through the administration fee levied. The utility determines what the bad debt allowance should be.

The common thread for what current stakeholders are proposing and what other jurisdictions have implemented is that marketers pay for bad debt in an unbundling environment. The challenge then is coming up with a bad debt deduction methodology that encourages the appropriate behaviour by marketers, treats customers equitably but does not act as a deterrent to unbundling.

Given the similar positions of the stakeholders on this issue, Terasen Gas believes then that the bad debt deduction methodology as originally proposed is still appropriate. Under the proposed methodology, marketers will be charged a % bad debt reduction on gross sales to their customers. As outlined in the Rate Schedule 36 Section 18.01 Bad Debt Factor, and as recently approved by BCUC Order G-90-03, the Bad Debt Factor will be fixed effective November 1st each year based on the overall bad debt recovery forecast used for the purposes of the Terasen Gas annual budget for the calendar year that includes such November 1st and shall remain unchanged until the next November 1st.

For calendar year 2004, Terasen Gas seeks approval to set the Bad Debt Factor to be used at 0.30% based on the 2003 historical experience (i.e. for Rate 2 and 3 customers; 0.26% Interior, 0.31% Lower Mainland). The 0.30% Bad Debt Factor will be used to calculate the bad debt reduction from marketers for the period November 1, 2004 to October 31, 2005.

The proceeds of the bad debt reduction will be credited to the deferral account utilized for the recovery of the capital implementation costs to offset some of the costs. Where Terasen Gas can justify the overall bad debt experience increases significantly as a result of unbundling, a portion of these proceeds would be allocated to offset the additional bad debt exposure.

Terasen Gas believes the proposed methodology properly aligns the interests of the stakeholders involved. Marketers are motivated to assist in the managing of bad debts as their efforts will have an impact on the overall bad debt ratio experienced by the utility. Commercial customers who will be paying for the capital implementation costs will benefit as the proceeds from the bad debt deduction charge will help mitigate some of the impact of the implementation costs. Also, it is unlikely that a 0.3% bad debt deduction charge would act as a significant barrier to customers contemplating participating in the Commercial Unbundling program. Finally, Terasen Gas' shareholders are not exposed to the risk of increased bad debt related to unbundling if Terasen Gas can demonstrate and identify the amount of any increased bad debt. Funds will have been set aside through the marketer bad debt deduction to potentially offset some of the increase bad debt exposure. Where there is no increased bad debt related to unbundling, Commercial customers will then receive the benefit of the marketer bad debt deduction.

5. TERASEN GAS STABLE COMMODITY RATE OFFERING

In this Application, Terasen Gas requests approval for the proposed deferral account treatment and the proposed cost recovery methods for the estimated capital implementation costs and the annual operating costs of providing the Stable Commodity Rate Residential Service effective.

5.1 Overview of Stable Commodity Rate Residential Service

By participating in the Stable Commodity Rate service, residential customers will be able to pay a fixed price for the gas commodity consumed, providing them with stability and predictability in their gas costs. To minimize the costs of implementation and avoid the potential confusion for residential customers that could arise from splitting the gas commodity from the midstream component, the fixed price provided by Terasen Gas will cover both the gas commodity and the midstream components.

The initial program is being offered for the period January 1, 2005 to December 31, 2005, with participation in the program limited to the first 20,000 eligible Rate 1 customers who sign up on a first come first serve basis.

Consistent with the Commercial Unbundling approach, Terasen Gas' desire is to minimize the costs to implement and operate the stable rate option

5.2 Capital Implementation Costs

For the Stable Commodity Rate option, the one-time capital costs to implement the program are minimal at an estimated cost of approximately $160,000, as it leverages the solution for Commercial Unbundling. The capital costs are required to cover the technical and process enhancements necessary to support the program.

5.3 Annual Operating Costs

Costs to operate the Stable Commodity Rate program include marketing expenditures to promote the offering; back-office expenditures for processing of customer enrolments and providing management reporting; and call centre related expenditures for the handling of customer inquiries. Examples of customer enrolment related activities are processing customer enrolment applications and sending out confirmation, renewal and rejection letters.

Of the operating costs required to support the Stable Commodity Rate program, a portion of the costs are “fixed” in nature (i.e. will be required to operate the program regardless of the number of customers participating) and the remaining portion are “variable” and dependent on the number of customers enrolling (i.e. enrolments requests received).

The “fixed” operating costs include the costs to market the program, provide basic customer education, produce management reporting and staff the call center to handle customer inquiries. These costs are necessary to provide the support to operate the program, regardless of the level of customer participation. For the first year, these “fixed” operating costs are estimated to be $390,000.

The “variable” operating costs include the costs to enrol customers in the Stable Commodity Rate program. The enrolment costs of a customer include reviewing and processing customers' applications, sending confirmation, rejection and renewal letters as required.

To limit the risk of committing to significant expenditures upfront with the potential for minimal customer participation, Terasen Gas has negotiated an operating agreement which variabilizes the costs associated with processing customer enrolments. As a result, Terasen Gas will only incur such enrolment costs when customer enrolment requests are received, thereby creating a greater cost-causality linkage.

5.4 Cost Recovery

5.4.1 Deferral Account Treatment

A deferral account called Stable Commodity Rate CCRA account will be required to record the costs as discussed in the previous sections and also to track the recoveries associated with the program.

5.4.2 Cost Recovery Methods

Two methods for recovery of the costs of the program are proposed. Terasen Gas proposes that the fixed operating costs and the one-time capital implementation costs at a combined total of approximately $550,000 for the first year of the program be recovered using a rider to the existing commodity charge applied to all residential customers that are eligible to participate in the Stable Commodity Rate program. The rationale is that these costs are necessary to provide choice to all eligible residential customers, regardless of whether a residential customer chooses to exercise choice. Therefore, all eligible residential customers should bear some portion of these costs as it provides them the right to exercise choice.

Assuming approximately 700,000 eligible residential customers at an average annual consumption rate of 108 gigajoules per year, the rider necessary for full recovery of costs over a one year amortization period is estimated at approximately $0.007 per gigajoule. The rider will be applied to all eligible residential customers with an effective date of January 1, 2005.

For recovery of variable operating costs, Terasen Gas proposes to charge an estimated premium of approximately $0.30 per gigajoule to the cost of gas procured for the Stable Commodity Rate program. By charging a premium to the cost of gas procured for Stable Commodity Rate customers, only those customers that participate in the program bear the responsibility for the incremental enrolment costs. Those customers who do not exercise choice will not have to pay a share of any incremental enrolment costs.

As part of the premium charged, there will also be an allowance added to offset a potential midstream rate adjustment that may occur at the beginning of the calendar year. For the Stable Commodity Rate offering, the price will be “fixed” in the third quarter of the current calendar year (i.e. 2004), prior to it being delivered to residential customers for the following calendar year (i.e. January – December 2005). From the time when the offering price is fixed to the end of the term of the program (i.e. December 2005), there is the possibility that the midstream rate could change. By allowing for some recovery of a potential midstream rate adjustment from Stable Commodity Rate customers, the risk of other rate classes having to absorb any under recovery that may occur from the Stable Commodity Rate program providing an aggregate “fixed” price for both commodity and midstream is reduced.

Terasen Gas expects the application of the two recovery methods will result in recovery of all costs of the program for any given term of the program. Any deficit or surplus that may arise is expected to be minimal and will be allocated to the eligible residential customer group the subsequent year of the term of the offering. For example, if a surplus or deficit develops for the program between January 1, 2005 and December 31, 2005, it will be allocated to eligible residential customers for recovery in calendar year 2006 via a gas cost rider.

Terasen Gas seeks approval to recover any imbalances that may occur for the Stable Commodity Rate using a gas cost rider applied to all eligible residential customers. Further, for as long as the Stable Commodity Rate program is in existence, Terasen Gas seeks approval to use the same proposed deferral account treatment and proposed cost recovery methods as outlined in the above sections.

5.4.3 Accounting Methodology

Included in Appendix 4 and 5 are two numerical examples of the accounting treatment for the Stable Commodity Rate program. The first example, labelled as “Base” scenario outlines the case where fixed price gas is purchased for 20,000 residential customers assuming an average annual use rate of 108 gigajoules per customer with actual sign-up rate at 20,000 customers, the maximum number of customers allowed initially for the program. The price per gigajoule for the Stable Commodity Rate offering is determined by adding a premium to the existing rate tariff to recover the expected variable operating costs for enrolment customers and to offset a potential midstream rate adjustment that may occur at the beginning of the calendar year.

In the second scenario where fewer customers sign-up than anticipated (i.e. 10,000 customers) and a slight increase occurs with the midstream rate, then the projected surplus decreases to approximately $70,000. The primary purpose of providing this scenario is to illustrate how any excess gas purchased that is not subscribed for is handled. The costs associated with this “excess” gas will be allocated to the Terasen Gas Commodity Provider account – CCRA to complement the existing core customers hedged volumes.

The same “excess” gas adjustment will be required when customers leave the Stable Commodity Rate program early for a number of reasons such as customers moving from their existing premises or those customers that voluntarily decide to terminate early from the program. In addition, to be consistent with the Essential Services Model, any difference between the baseload delivery requirement and the actual customer consumption volumes will be transferred to the MCRA.

5.4.4 Scenarios of Cost Recoveries – Under / Over Recovery

Terasen Gas expects any imbalances in the deferral account for the Stable Commodity Rate program over time to be immaterial.

The table below outlines the base case scenario along with three alternative scenarios. The base case scenario and scenario #1 have been discussed in the above section under Accounting Methodology.

SCENARIO ANALYSIS	Scenario Number	Recovery + Over / - Under
20,000 customers sign-up No change in midstream rate	Base	$ 352,230
Only 10,000 customers sign-up $0.10 per gj increase in midstream rate	1	$ 68,110
3,000 customers leave early $0.10 per gj increase in midstream rate	2	$ 48,294
5,000 customers leave early $0.30 per gj increase in midstream rate Higher call volumes than anticipated	3	$ (458,730)

Scenarios #2 and #3 have been provided to further illustrate what possible imbalances could result in the Stable Commodity Rate deferral account. Scenario #2 models a possible situation where customers leave the program early, leading to reduced recoveries of variable enrolment fees. With fewer customers, volumes of gas consumed under the Stable Commodity Rate program will decline, diminishing the possible recoveries of the $0.30 per gigajoule premium for variable operating costs.

Scenario #3 outlines a worst case scenario where a significant number of customers leave the program early, a significant midstream rate increase occurs and higher customer inquiries are received regarding the Stable Commodity Rate program.

6. SCOPE CHANGE FOR COMMERCIAL COMMODITY UNBUNDLING & STABLE RATE OPERATING AGREEMENTS

6.1 Commercial Unbundling and Stable Rate

6.1.1 Scope Changes

The Client Services Agreement negotiated in December 2001 was intended to transfer to CustomerWorks Limited Partnership the responsibility for and funding required to provide the scope of services and level of performance as documented in the service schedules attached to the agreement at that time. The scope of services and level of performance were to be consistent with the level of service Terasen Gas provided to their customers at that time. Any change to either the scope of services provided or the level of services required to be provided for existing services was expected to trigger a scope change to the agreement.

Following is an excerpt from the Client Service Agreement defining the triggers to be considered which could initiate a change in scope.

> **"15. Scope Change Process**
>
> **15.1 Triggers.** The parties agree that scope changes to Client Services (a "Scope Change") may be required from time to time for a variety of reasons including, but not limited to:
>
> (a) need for increased functionality in a system including increased functionality beyond that contemplated in the Project Transfer Agreement;
>
> (b) increase/decrease in Customer base exclusive of increases due to natural population growth;
>
> (c) change in BC Gas' needs;
>
> (d) change in the law or changes initiated by the British Columbia Utilities Commission;
>
> (e) CustomerWorks' or BC Gas' desire to change some aspect of the Client Services to reflect improvements in prevailing industry standards or practices; or
>
> (f) other circumstances which reasonably require the parties to request a change in the:
>
> (i) scope of Client Services;
>
> (ii) Performance Standards; or

(iii) Base Fees; or

(iv) Client Service delivery practices."

In the April 18, 2002 Commission response confirming approval of the Application for the Disposition of Property and Approval of Customer Care Agreements, the Commission has directed that any significant improvement initiatives or scope changes pursuant to the Client Services Agreement are to be submitted to the Commission for review. Attached for Commission review are two new service schedules that will be appended to the existing Client Services Agreement. Schedule “F”, Commercial Unbundling Operational Services, describes the scope of services, service guidelines and pricing related to the implementation of Commodity Unbundling for commercial customers and Schedule “G”, Stable Rate Program Operational Services, describes the scope of services, service guidelines and pricing related to the implementation of an alternate commodity alternative to be offered through the Utility to residential customers. Terasen Gas requests approval of the rates included in these two new service schedules effective April 1, 2004.

6.1.2 Schedule "F" Commercial Unbundling Operational Services

This new service schedule outlines the services that will be provided by CustomerWorks Limited Partnership through Accenture Business Services, it’s outsourced service provider directly related to the introduction of commodity choice for commercial customers. The scope of services includes the specific activities related to customer enrolment, bill presentment of midstream and marketer charges on commercial customer statements and customer inquiry support related to the customer education program and in response to customer billing inquiries and complaints.

The services described in this schedule were not anticipated when the original Client Services Agreement was negotiated in 2001 and Approved by the Commission in April of 2002. These are new services that could not have been anticipated at the time the Client Services agreement was negotiated and are described in this schedule as incremental to the services currently provided by CustomerWorks LP. We have elected to isolate the services and costs related to commercial unbundling into a separate schedule as we have adopted a different pricing model for these services as described below. A copy of Schedule "F" is included as Appendix 6. The rates included in this schedule will be considered draft pending approval of this Application.

6.1.2.1 Pricing

Through discussions with the Commission and other interested parties the scope and scale of commercial unbundling has been contained to limit the degree of participation in the initial stages in order to minimize the capital requirements related to implementation and yet provide an opportunity to assess the value of the opportunity to marketers and customers. Interfaces and processes have been automated to the degree possible ensuring that a viable service offering is made available.

The pricing structure that has been negotiated includes both fixed and variable components. The base fees of $28,996 for 2004 and $31,632 for 2005 and 2006, described in Section 5.1 of Schedule "F" include the costs associated with providing the base functionality and infrastructure to support the customer care business processes. These costs relate to the fixed components of both call centre and back office operations. Not included at this time are the additional costs associated with information technology sustainment which are still being negotiated. The IT sustainment component of the base fee was not included in the July 18, 2003 submission due to the uncertainty, at that time of the significance of the costs required to support the technology components of the commercial unbundling solution. Preliminary negotiations indicate that these costs will likely be not greater than $60,000 in 2004 and $90,000 for subsequent years. When Terasen Gas finalizes the IT sustainment costs a revised Schedule "F" will be filed with the Commission. This is anticipated to be completed by the end of January 2004.

Excluding the base fees described above and given the uncertainty related to the degree of interest and participation, we are proposing that the balance of the costs related to commercial unbundling be provided at a fixed transaction rate calculated on a per occurrence basis.

The most significant variable in this initiative, and the most difficult to forecast, is the level of customer participation. Although the infrastructure has been designed to handle up to 10,000 customers in the first enrolment cycle for example, the numbers will be largely dependent on the success of the customer education program and the marketer campaigns. In order to ensure that the total cost incurred is proportional to the level of interest, we have negotiated a fixed cost per enrolment exception of $23.70 to address this potential volatility in volume. Most enrolment requests are expected to be handled through the automated systems and therefore are included in the base fee. The enrolment exceptions however will require manual intervention to investigate and process and are expected to result in significant cost to resolve.

As the program evolves over time and unbundling becomes part of the base service offering for all customers, we intend to revisit this costing model in order to fix the price and incorporate the costs into the core long-term scope of services provided under the Client Services Agreement.

A second variable pricing component relates to the level of marketer interest. A set fee of $1,776 per marketer group set-up has been negotiated. This fee covers the set up of a new marketer service offering in all Terasen Gas' systems and will enable the processing of enrolments, consumption data extracts and marketer charges on customer bills. The transactional nature of this charge will ensure that ratepayers will pay in proportion to the degree of market activity. This will provide more flexibility going forward to accommodate changes to marketer preferences and service offerings. The variable cost nature of this component ensures that there will be flexibility depending on marketer interest.

A second variable fee related to marketer participation is the rate change fee which will be applied to any marketer requested rate changes that occurs after the group has been established and billed. A fee of $91 will be applied on a per group basis. The first rate changes under this program are not expected to occur prior to November 2005.

The final cost component related to commercial unbundling is the transactional fee associated with support for marketer requests for consumption information in advance of customer enrolment. Marketers have indicated an interest in being able to obtain information about historical customer consumption in advance of enrolment in order to support their development of pricing alternatives. With the implementation of the new privacy legislation which came into effect on January 1, 2004, the process to retrieve this information based on marketer requests will require written consent from the customer authoring the Utility to release the information to the marketer. We believe the fee of $30 is reasonable in light of the manual nature of this process and the requirement under to the privacy legislation to track both requests and responses. Given that customer consumption information is currently available directly from the customer through their historical billings as well as through the Account Online internet service, we anticipate the volume of requests in this area will be relatively low.

6.1.3 Schedule "G" Stable Rate Program Operational Services

This new service schedule outlines the services that will be provided by CustomerWorks Limited Partnership through Accenture Business Services, it's outsourced service provider, directly related to the introduction of an alternate rate offering for residential customers by the Utility. The scope of services includes the specific activities related to customer enrolment and confirmation, bill presentment and customer inquiry support related to the customer education program and in response to customer inquiries and complaints.

The objectives of the Stable Commodity Rate Residential Service are to educate residential customers on choice of supply of natural gas and to serve as an intermediate step to assess consumer response to commodity choice.

As discussed previously in relation to commercial unbundling, the services described in this schedule were not anticipated when the original Client Services Agreement was negotiated in 2001 and approved by the Commission in April of 2002. These are new services that could not have been anticipated at the time the Client Services agreement was negotiated and are described in this schedule as incremental to the services currently provided by CustomerWorks Limited Partnership. We have also elected to isolate the services and costs related to the new stable rate option into a separate schedule as we have adopted a different pricing model for these services as described below. A copy of Schedule "G" has been included in Appendix 7. The rates included in this schedule will be considered draft pending approval of this Application.

6.1.3.1 Pricing

Similar to the Commercial Unbundling program, the stable rate option is being implemented with the expectation that participation will be contained in the first year to a maximum of 25,000 enrolment requests leading to 20,000 full term participants. Given some uncertainty related to how long this program will continue to be offered, the service schedule has only been negotiated to support a one year program with the possibility of a one year extension. The pricing model as described below has again been designed to include both a fixed and a variable component. In addition, for the stable rate program we have anticipated an optional second year and have obtained separate pricing for this extension.

The base fees of $36,600 for 2004 and $73,200 for 2005, described in Section 5.1 include the costs associated with providing the operational infrastructure to support the customer care business processes specifically required to support the stable rate program. These costs relate to the fixed components of both call centre and back office operations and are based on the assumption that, although the commercial unbundling infrastructure will be used wherever possible, much of the processing related to the stable rate program will be manual. Additionally, these costs are based on a fixed one year program. Any costs related to the possible renewal of this option are included in the second operating cycle.

Due to the challenges in forecasting customer interest and participation in this new rate option, Terasen Gas' has negotiated a variable component related to enrolment activity levels. The cost to process a customer enrolment request received will be $26 per transaction for the first cycle of the program and $30 per transaction for the optional second cycle. Included in this component are the activities related to enrolling the customers, confirming the customer's intent to participate through a confirmation letter, and initiating the data update to move the customer to their new rate option.

The costs associated with the optional second cycle are slightly higher because of the anticipated renewal activities associated with the first year enrolments. Should the second cycle not be approved, a separate change request will be submitted to handle the removal of these customers from the stable rate option and their return to standard gas service.

7. POST-IMPLEMENTATION REVIEW & NEXT STEPS

Terasen Gas requests approval for the proposed post-implementation review process with the next steps and timeframes discussed in the following sections.

An annual post implementation review workshop is recommended for the first quarter of each calendar year to discuss topics such as revisions to the Code of Conduct for Gas Marketers, past and future customer education efforts and concerns about Marketer Licensing process and requirements. The workshop will provide a forum for stakeholders to comment and provide suggestions for improvements to the Commodity Unbundling program.

The first "unbundling" workshop is anticipated for 1st quarter 2005. At the same time, Terasen Gas will be able to share the initial results of the Stable Commodity Rate program including providing summary statistics for customer participation, total gas consumed under the program and the projected imbalance for the deferral account related to the first year of the offering.

Rate applications for setting of riders for the recovery of Commercial Unbundling and Stable Commodity Rate implementation, operating and maintenance costs will be filed in the 4th quarter of each calendar year with the first set of applications to be filed in 4th quarter 2004. In addition, Terasen Gas anticipates filing a rate application for approval of the tariff rate for the 1st year of the Stable Commodity Rate offering in the third quarter of 2004 just prior to the enrolment of customers in the 4th quarter of 2004.

Quarterly reports after each entry date will be filed with the Commission outlining marketer and customer participation rates for the Commercial Unbundling program. In addition, reports outlining any items of interest such as backstopping charges will be provided as requested. These reports will be deemed confidential and submitted only to Commission staff for review as the sensitive nature of the information may impact a gas marketer's competitive position if improperly disclosed.

As mentioned under Section 2.4.1.1, Terasen Gas is proposing the establishment of a Commodity Unbundling Standing Committee of interested parties as part of the regular process to review Midstream rates each year. Terasen Gas anticipates this committee to meet in the first quarter of each year.

APPENDIX 1 COST ALLOCATION FROM GCRA TO CCRA / MCRA

Terasen Gas Inc. - Consistent Cost Allocation From GCRA to CCRA / MCRA

GCRA (Gas Cost Reconciliation Account)							
	Rate Class Cost Allocation Methodology						
Type of Cost / Recovery	**Rate 1**	**Rate 2**	**Rate 3**	**Rate 4**	**Rate 5**	**Rate 6**	**Rate 7**
Load Factors	**29.2%**	**26.9%**	**35.4%**	**n/a**	**50.0%**	**100.0%**	**n/a**
• Administrative costs	**LF**	**LF**	**LF**	**N/A**	**LF**	**LF**	**N/A**
• Pipeline Demand Charges (Duke, TCPL-Nova, NWP)	**LF**	**LF**	**LF**	**N/A**	**LF**	**LF**	**N/A**
• Pipeline Commodity Tolls	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Pipeline Fuel Gas	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Storage Reservation Charges	**LF**	**LF**	**LF**	**N/A**	**LF**	**LF**	**N/A**
• Storage Injection & withdrawal fuel	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Storage commodity costs	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Term Commodity Purchases	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Seasonal Commodity Purchases	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Spot Commodity Purchase Costs	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Peaking Gas Purchase Costs	GJ	GJ	GJ	GJ	GJ	GJ	GJ
70/30 Commodity purchases	**LF**/GJ	**LF**/GJ	**LF**/GJ	GJ	**LF**/GJ	**LF**/GJ	GJ
• Hedging Gains/Losses	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Exchange Rate ($US to $CDN) Gains/Losses	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Mitigation Activities / Off-System Sales	**LF**/GJ	**LF**/GJ	**LF**/GJ	GJ	**LF**/GJ	**LF**/GJ	GJ
• Gas Cost Recoveries	GJ	GJ	GJ	GJ	GJ	GJ	GJ

CCRA (Commodity Cost Reconciliation Account)							
	Rate Class Cost Allocation Methodology						
Type of Cost / Recovery	**Rate 1**	**Rate 2**	**Rate 3**	**Rate 4**	**Rate 5**	**Rate 6**	**Rate 7**
Load Factors	**29.2%**	**26.9%**	**35.4%**	**n/a**	**50.0%**	**100.0%**	**n/a**
• Administrative costs	**LF**	**LF**	**LF**	**N/A**	**LF**	**LF**	**N/A**
• Term Commodity Purchases	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Seasonal Commodity Purchases	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Spot Commodity Purchase Costs	GJ	GJ	GJ	GJ	GJ	GJ	GJ
70/30 Commodity purchases	**LF**/GJ	**LF**/GJ	**LF**/GJ	GJ	**LF**/GJ	**LF**/GJ	GJ
• Hedging Gains/Losses	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Exchange Rate ($US to $CDN) Gains/Losses	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Gas Cost Recoveries	GJ	GJ	GJ	GJ	GJ	GJ	GJ

MCRA (Midstream Cost Reconciliation Account)							
	Rate Class Cost Allocation Methodology						
Type of Cost / Recovery	**Rate 1**	**Rate 2**	**Rate 3**	**Rate 4**	**Rate 5**	**Rate 6**	**Rate 7**
Load Factors	**29.2%**	**26.9%**	**35.4%**	**n/a**	**50.0%**	**100.0%**	**n/a**
• Administrative costs	**LF**	**LF**	**LF**	**N/A**	**LF**	**LF**	**N/A**
• Pipeline Demand Charges (Duke, TCPL-Nova, NWP)	**LF**	**LF**	**LF**	**N/A**	**LF**	**LF**	**N/A**
• Pipeline Commodity Tolls	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Pipeline Fuel Gas	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Storage Reservation Charges	**LF**	**LF**	**LF**	**N/A**	**LF**	**LF**	**N/A**
• Storage Injection & withdrawal fuel	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Storage Commodity Purchase Costs	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Spot Commodity Purchase Costs	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Peaking Gas Purchase Costs	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Exchange Rate ($US to $CDN) Gains/Losses	GJ	GJ	GJ	GJ	GJ	GJ	GJ
• Mitigation Activities / Off-System Sales	**LF**/GJ	**LF**/GJ	**LF**/GJ	GJ	**LF**/GJ	**LF**/GJ	GJ
• Gas Cost Recoveries	GJ	GJ	GJ	GJ	GJ	GJ	GJ

APPENDIX 2 GAS COST RATE SCHEDULES

LM1
FlDec2k4Dec4CCRAr7
04-01-16
16:00

TERASEN GAS INC. - LOWER MAINLAND SERVICE AREA
LOWER MAINLAND/INLAND/COLUMBIA COST OF GAS BY RATE SCHEDULE - CCRA
FORECAST FOR THE 12 MONTHS ENDING DECEMBER 31, 2004
($000)

CCRA
TABLE B
LOWER MAINLAND
PAGE 1
December 4, 2003 Forward Pricing
January 1, 2004 - December 31, 2004 Fl.

Line No.	Particulars	Residential Rate 1	Commercial Rate 2	Commercial Rate 3	General Firm Service Rate 5	NGV Rate 6	Subtotal	Seasonal Rate 4	Interruptible Rate 7	Interruptible Rate 14 (Rate 10)	Off-System Sales		Squamish	Burrard Thermal Firm	Burrard Thermal Interruptible	Total Sales
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
1	**SUMMARY**															
2																
3																
4	**Sales Volume (TJ)**	53,103.3	15,247.8	15,198.5	5,261.9	245.9	89,057.4	109.4	100.1	1,401.3	12,458.3		354.3	-	-	103,480.8
5																
6																
7	**Gas Purchase Costs ($000)**															
8	Commodity Costs	$ 302,182.5	$ 86,767.1	$ 86,486.5	$ 29,942.7	$ 1,399.3	$ 506,778.0	$ 365.3	$ 458.3	$ -	$ -		$ 2,016.1	$ -	$ -	$ 509,617.7
9	Commodity Tolls and Fees	-	-	-	-	-	-	-	-	-	-		-	-	-	0.0
10	Fixed Costs	17,708.1	5,519.4	4,180.5	1,024.8	23.9	28,456.7	-	-	-	-		113.9	-	-	28,570.6
11	Total Commodity & Demand	319,890.6	92,286.4	90,667.1	30,967.4	1,423.2	535,234.7	365.3	458.3	-	-		2,130.1	0	0.0	538,188.3
12		-	-	-	-	-	-	-	-	-	-		-	-	-	-
13	Hedge Loss (Gain) - Variable Cost	(452.1)	(129.8)	(129.4)	(44.8)	(2.1)	(758.2)	(0.5)	-	-	-		(3.0)	-	-	(761.8)
14	Core Market Administrative Costs - Fixed Cost	218.2	68.0	51.5	12.6	0.3	350.6	-	-	-	-		1.4	-	-	352.0
15		$ 319,656.6	$ 92,224.6	$ 90,589	$ 30,935.3	$ 1,421.4	$ 534,827.1	$ 364.7	$ 458.3	$ -	$ -		$ 2,128.4	$ -	$ -	$ 537,778.6
16																
17																
18	**Unit Costs ($/GJ)**															
19	Commodity Costs	$ 5.6905	$ 5.6905	$ 5.6905	$ 5.6905	$ 5.6905	$ 5.6905	$ 3.3389	$ 4.5783	$ -	$ -		$ 5.6905	$ -	$ -	$ 4.9248
20	Commodity Tolls and Fees	-	-	-	-	-	-	-	-	-	-		-	-	-	-
21	Fixed Costs	0.3334	0.3619	0.2750	0.1947	0.0972	0.3196	-	-	-	-		0.3215	-	-	0.2761
22	Commodity & Demand / GJ	6.0239	6.0524	5.9655	5.8852	5.7877	6.0101	3.3389	4.5783	-	-		6.0120	-	-	5.2009
23		-	-	-	-	-	-	-	-	-	-		-	-	-	-
24	Hedge Loss (Gain) - Variable Cost	(0.0085)	(0.0085)	(0.0085)	(0.0085)	(0.0085)	(0.0085)	(0.0050)	-	-	-		(0.0085)	-	-	(0.0074)
25	Core Market Administrative Costs - Fixed Cost	0.0041	0.0045	0.0034	0.0024	0.0012	0.0039	-	-	-	-		0.0040	-	-	0.0034
26		$ 6.0195	$ 6.0484	$ 5.9604	$ 5.8791	$ 5.7804	$ 6.0055	$ 3.3339	$ 4.5783	$ -	$ -		$ 6.0075	$ -	$ -	$ 5.1969
27								**Tariff**	**Fixed Price Option**				**Rates 1&3**			
28								**Equal To**	**Equal To**				**Prorated**			
29	**AVERAGE COST OF GAS - $/GJ**							**Rate 5**	**Rate 5**				**Rate**			
30	Forecast (CCRA with Dec 4, 2003 prices)	$ 6.0195	$ 6.0484	$ 5.9604	$ 5.8791	$ 5.7804	$ 6.0055	$ 5.8791	$ 5.8791	$ -			$ 6.0120	$ -	$ -	
31																
32	Approved Jan 1, 2004 Bundled rate	7.1666	7.2521	6.9915	6.7507	6.4595	7.1249	6.7507	6.7507	3.5676			7.1443	-	-	
33																
34	Forecast (MCRA with Dec 4, 2003 prices)	$ 1.1471	$ 1.2037	$ 1.0311	$ 0.8716	$ 0.6791	$ 1.1194	$ 0.8716	$ 0.8716	$ 3.5676			$ 1.1323	$ -	$ -	
35																
36																

Tab 2, Table B, Lower mainland, Page 1

INL1
FIDec2k4Dec4CCRAr7
04-01-16
16:00

TERASEN GAS INC. - INLAND SERVICE AREA
LOWER MAINLAND/INLAND/COLUMBIA COST OF GAS BY RATE SCHEDULE - CCRA
FORECAST FOR THE 12 MONTHS ENDING DECEMBER 31, 2004
($000)

CCRA
TABLE B
INLAND
PAGE 1.1
December 4, 2003 Forward Pricing
January 1, 2004 - December 31, 2004 FI.

Line No.	Particulars	Residential Rate 1	Commercial Rate 2	Commercial Rate 3	General Firm Service Rate 5	NGV Rate 6		Subtotal	Seasonal Rate 4	Large Industrial Interruptible Sales Rate 7	Large Industrial Interruptible Sales Rate 14	Columbia	Total Sales	Total Sales LM & ING
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**SUMMARY**													
2														
3														
4	**Sales Volume (TJ)**	17,957.9	5,258.2	3,005.7	988.2	22.8	-	27,232.8	125.2	21.3	289.2	-	27,668.5	131,149.3
5														
6														
7	**Gas Purchase Costs ($000)**													
8	Commodity Costs	$ 102,188.8	$ 29,921.6	$ 17,103.8	$ 5,623.3	$ 129.8	$ -	$ 154,967.3	$ 426.9	$ 97.5	$ -	$ -	$ 155,491.7	$ 665,109.4
9	Commodity Tolls and Fees	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0
10	Fixed Costs	5,988.3	1,903.4	826.7	192.5	2.2	-	8,913.1	-	-	-	-	8,913.1	37,483.6
11	Total Commodity & Demand	108,177.1	31,825.0	17,930.5	5,815.8	131.9	-	163,880.4	426.9	97.5	-	-	164,404.8	702,593.1
12		-	-	-	-	-	-	-	-	-	-	-	-	-
13	Hedge Loss (Gain) - Variable Cost	(152.9)	(44.8)	(25.6)	(8.4)	(0.2)	-	(231.8)	(0.6)	-	-	-	(232.5)	(994.2)
14	Core Market Administrative Costs - Fixed Cost	73.8	23.5	10.2	2.4	0.0	-	109.8	-	-	-	-	109.8	461.9
15		$ 108,098.0	$ 31,803.7	$ 17,915.1	$ 5,809.7	$ 131.8	$ -	$ 163,758.3	$ 426.3	$ 97.5	$ -	$ -	$ 164,282.1	$ 702,060.7
16														
17														
18	**Unit Costs ($/GJ)**													
19	Commodity Costs	$ 5.6905	$ 5.6905	$ 5.6905	$ 5.6905	$ 5.6908	$ -	$ 5.6905	$ 3.4098	$ 4.5782	$ -	$ -	$ 5.6198	$ 5.0714
20	Commodity Tolls and Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fixed Costs	0.3334	0.3620	0.2750	0.1948	0.0959	-	0.3273	-	-	-	-	0.3222	0.2858
22	Commodity & Demand / GJ	6.0239	6.0525	5.9655	5.8853	5.7867	-	6.0178	3.4098	4.5782	-	-	5.9420	5.3572
23		-	-	-	-	-	-	-	-	-	-	-	-	-
24	Hedge Loss (Gain) - Variable Cost	(0.0085)	(0.0085)	(0.0085)	(0.0085)	(0.0085)	-	(0.0085)	(0.0051)	-	-	-	(0.0084)	(0.0076)
25	Core Market Administrative Costs - Fixed Cost	0.0041	0.0045	0.0034	0.0024	0.0012	-	0.0040	-	-	-	-	0.0040	0.0035
26		$ 6.0195	$ 6.0485	$ 5.9604	$ 5.8792	$ 5.7794	$ -	$ 6.0133	$ 3.4047	$ 4.5782	$ -	$ -	$ 5.9376	$ 5.3531
27									**Tariff**	**Fixed Price Option**				
28									**Equal To**	**Equal To**				
29	**AVERAGE COST OF GAS - $/GJ**								**Rate 5**	**Rate 5**				
30	Forecast (CCRA with Dec 4, 2003 prices)	$ 6.0195	$ 6.0485	$ 5.9604	$ 5.8792	$ 5.7794	$ -	$ 6.0133	$ 5.8792	$ 5.8792	$ -	$ -		
31														
32	Approved Jan 1, 2004 Bundled rate	7.0602	7.1410	6.8950	6.6668	6.3947	-	7.0427	6.6668	6.6668	3.4924	-		
33														
34	Forecast (MCRA with Dec 4, 2003 prices)	$ 1.0407	$ 1.0925	$ 0.9346	$ 0.7876	$ 0.6153	$ -	$ 1.0294	$ 0.7876	$ 0.7876	$ 3.4924	#N/A		
35														
36														

Tab 2, Table B, Inland Page 1.1

COL1
FIDec2k4Dec4CCRAr7
04-01-16
16:00

TERASEN GAS INC. - COLUMBIA SERVICE AREA
LOWER MAINLAND/INLAND/COLUMBIA COST OF GAS BY RATE SCHEDULE - CCRA
FORECAST FOR THE 12 MONTHS ENDING DECEMBER 31, 2004
($000)

CCRA
TABLE B
COLUMBIA
PAGE 1.2
December 4, 2003 Forward Pricing
January 1, 2004 - December 31, 2004 Fl.

Line No.	Particulars	Residential Rate 1	Commercial Rate 2	Commercial Rate 3	General Firm Service Rate 5	NGV Rate 6	Seasonal Rate 4	Subtotal	Large Industrial Interruptible Sales Rate 7				Total Sales	Total Sales LM, Inl & Col Serv. Areas
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**SUMMARY**													
2														
3														
4	**Sales Volume (TJ)**	2,104.0	715.6	332.5	154.5	-	-	3,306.6	-	-	-	-	3,306.6	134,455.9
5														
6														
7	**Gas Purchase Costs ($000)**													
8	Commodity Costs	$11,972.7	$ 4,072.1	$ 1,892.1	$ 879.2	$ -	$ -	$18,816.1	$ -	$ -	$ -	$ -	$ 18,816.1	$ 683,925.5
9	Commodity Tolls and Fees	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0
10	Fixed Costs	701.6	259.0	91.5	30.1	-	-	1,082.2	-	-	-	-	1,082.2	38,565.8
11	Total Commodity & Demand	12,674.3	4,331.1	1,983.6	909.2	-	-	19,898.2	-	-	-	-	19,898.2	722,491.3
12		-	-	-	-	-	-	-	-	-	-	-	-	-
13	Hedge Loss (Gain) - Variable Cost	(17.9)	(6.1)	(2.8)	(1.3)	-	-	(28.2)	-	-	-	-	(28.2)	(1,022.4)
14	Core Market Administrative Costs - Fixed Cost	8.6	3.2	1.1	0.4	-	-	13.3	-	-	-	-	13.3	475.2
15		$12,665.1	$ 4,328.2	$ 1,981.9	$ 908.3	$ -	$ -	$19,883.4	$ -	$ -	$ -	$ -	$ 19,883.4	$ 721,944.1
16														
17														
18	**Unit Costs ($/GJ)**													
19	Commodity Costs	$ 5.6905	$ 5.6905	$ 5.6904	$ 5.6904	$ 5.6908	$ -	$ 5.6905	$ -	$ -	$ -	$ -	$ 5.6905	$ 5.0866
20	Commodity Tolls and Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fixed Costs	0.3334	0.3619	0.2753	0.1945	0.0959	-	0.3273	-	-	-	-	0.3273	0.2869
22	Commodity & Demand / GJ	6.0239	6.0524	5.9657	5.8849	5.7867	-	6.0178	-	-	-	-	6.0178	5.3735
23		-	-	-	-	-	-	-	-	-	-	-	-	-
24	Hedge Loss (Gain) - Variable Cost	(0.0085)	(0.0085)	(0.0085)	(0.0085)	(0.0085)	-	(0.0085)	-	-	-	-	(0.0085)	(0.0076)
25	Core Market Administrative Costs - Fixed Cost	0.0041	0.0045	0.0034	0.0024	0.0012	-	0.0040	-	-	-	-	0.0040	0.0035
26		$ 6.0195	$ 6.0484	$ 5.9606	$ 5.8788	$ 5.7794	$ -	$ 6.0133	$ -	$ -	$ -	$ -	$ 6.0133	$ 5.3694
27							**Tariff**		**Fixed Price Option**					
28							**Equal To**		**Equal To**					
29	**AVERAGE COST OF GAS - $/GJ**						**Rate 5**		**Rate 5**					
30	Forecast (CCRA with Dec 4, 2003 prices)	$ 6.0195	$ 6.0484	$ 5.9606	$ 5.8788	$ 5.7794	$ 5.8788	$ 6.0133	$ 5.8788					
31														
32	Approved Jan 1, 2004 Bundled rate	7.1960	7.2787	7.0274	6.7941	6.3947	6.7941	7.1782	6.7941					
33														
34	Forecast (MCRA with Dec 4, 2003 prices)	$ 1.1765	$ 1.2303	$ 1.0668	$ 0.9153	$ 0.6153	$ 0.9153	$ 1.1649	$ 0.9153					
35														
36														

Tab 2, Table B, Columbia, Page 1.2

APPENDIX 3 RATE SCHEDULE 36 APPENDIX "B"

Appendix "B"

Table of Charges

Backstopping Gas Sale Price

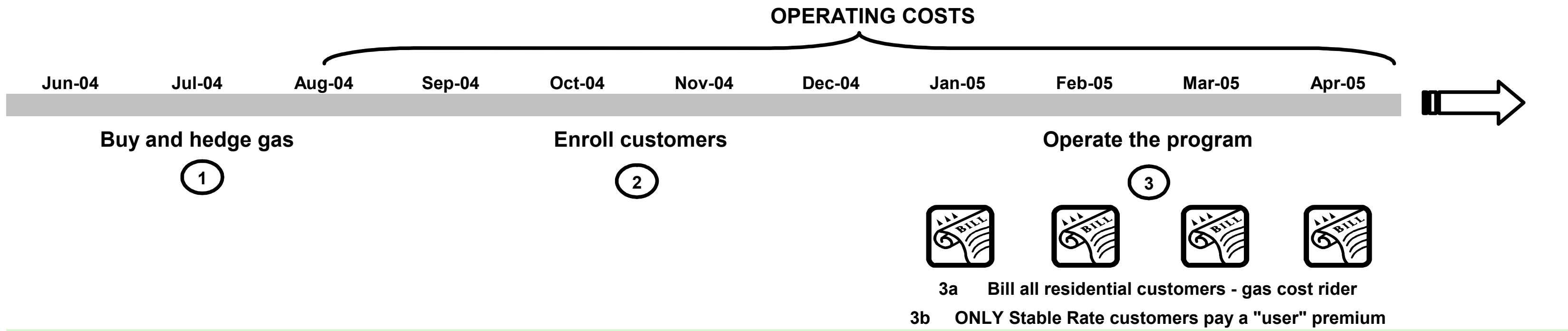
1. In the event the Backstopping Gas sale arose due to a delivery shortfall caused by the actions of Marketer, the Backstopping Gas price shall be the Blended Price plus two times the highest Gas Daily Common High for the market hubs associated with each of the Receipt Points where Marketer has a Receipt Point Delivery Requirement under this Rate Schedule and the Rate Schedule 36 Service Agreement.

2. In the event the Backstopping Gas sale arose due to a delivery shortfall caused by the action of Terasen Gas, the Backstopping Gas price shall be zero.

Transaction Fees

1.	Marketer Group Administration Fee	$150.00
2.	Customer Administration Fee	$0.40
3.	Historical Gas Consumption Request Fee	$30.00

APPENDIX 4 NUMERICAL EXAMPLE OF STABLE COMMODITY RATE ACCOUNTING – BASE SCENARIO



CCRA
Terasen Gas Commodity

	Debit	Credit
2	$ -	

MCRA
Terasen Gas Midstream

	Debit	Credit
3b		$ 2,160,000

Stable Rate CCRA

	Debit	Credit	
1	$ 15,120,000		
2		$ -	
2a	$ 650,000		
3	$ 550,000		
3a		$ 549,990	
3b		$ 16,122,240	
	$ 16,320,000	$ 16,672,230	
Balance		$ 352,230	Over Recovery

Reason
Addition of 2% premium to account for potential midstream adjustment
~ 2% of $8.00 = $0.16 per Gj X 20,000 X 108 Gjs = $345,600

ACCOUNTING ENTRIES - during the term of the offering

1 **Terasen Gas purchases gas for 20,000 customers X 108 Gj avg annual use X $7 per GJ**
- $7 per Gj excludes midstream component

***** **Stable Rate price set at 5.8% premium to tariff rate of $8 per Gj**
- ($7 for commodity, $1 for midstream) X 1.058 = $8.464 per Gj

2 **20,000 residential customers sign up**
- No projected excess gas

2a **Enrollment costs**
- 25,000 enrollment requests received; 20,000 customers actually enrolled
- Cost is $26 per enrollment request processed

***** **Calculate baseload delivery requirement**
- 20,000 customers X 108 Gjs / 365 days = 5,917 Gjs per day

3 **Program support costs**
- Education, advertising, call centre, implementation, miscellaneous

3a **Recovery of program support costs from all eligible residential customers**
- 700,000 customers X 108 Gjs X $0.0072 per Gj

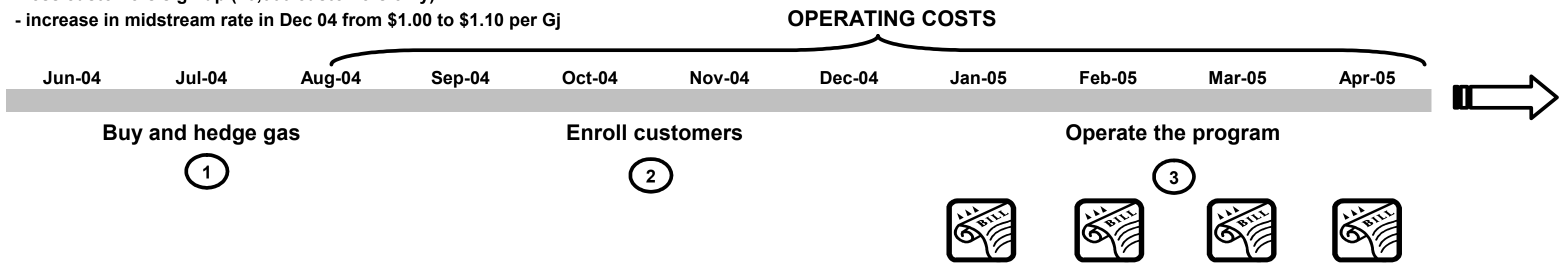
3b **Stable Rate customer billing (assume no customers leave early)**
- assume no customers leave early
- annual customer consumption equals baseload delivery requirements

- $7.464 per Gj goes to Stable Rate CCRA
- $7.464 per Gj X 20,000 X 108 Gjs per year

- $1 per Gj goes to Terasen Gas Midstream MCRA
- $1 per Gj X 20,000 customers X 108 Gjs per year

APPENDIX 5 NUMBERICAL EXAMPLE OF STABLE COMMODITY RATE ACCOUNTING – SCENARIO #1

Scenario
- **less customers sign up (10,000 customers only)**
- **increase in midstream rate in Dec 04 from $1.00 to $1.10 per Gj**



3a Bill all residential customers - gas cost rider

3b ONLY Stable Rate customers pay a "user" premium

CCRA

Terasen Gas Commodity

2	$ 7,560,000	

MCRA

Terasen Gas Midstream

3b		$ 1,188,000

Stable Rate CCRA

1	$ 15,120,000		
2		$ 7,560,000	
2a	$ 325,000		
3	$ 550,000		
3a		$ 549,990	
3b		$ 7,953,120	
	$ 15,995,000	$ 16,063,110	
Balance		$ 68,110	Over Recovery

Reason
Addition of 2% premium to account for potential midstream adjustment
~ 2% of $8.00 = $0.16 per Gj X 10,000 X 108 Gjs
Midstream rate only increased $0.10 per Gj

Difference of $0.06 per Gj is over recovery

ACCOUNTING ENTRIES - during the term of the offering

1 **Terasen Gas purchases gas for 20,000 customers X 108 Gj avg annual use X $7 per GJ**
- **$7 per GJ excludes midstream component**

***** **Stable Rate price set at 5.8% premium to tariff rate of $8 per Gj**
- **($7 for commodity, $1 for midstream) X 1.058 = $8.464 per Gj**

2 **10,000 residential customers sign up**
- **Excess gas (10,000 X 108 Gjs X $7 per Gj) transferred out**

2a **Enrollment costs**
- **12,500 requests received; 10,000 actual enrolled**
- **Cost is $26 per enrollment request processed**

***** **Calculate baseload delivery requirement**
- **10,000 customers X 108 Gjs / 365 days = 2,959 Gjs per day**

3 **Program support costs**
- **Education, advertising, call centre, implementation, miscellaneous**

3a **Recovery of program support costs from all eligible residential customers**
- **700,000 customers X 108 Gjs X $0.0072 per Gj**

3b **Stable Rate customer billing (assume no customers leave early)**
- **assume no customers leave early**
- **annual customer consumption equals baseload delivery requirements**

- **$7.364 per Gj goes to Stable Rate CCRA**
- **$7.364 per Gj X 10,000 X 108 Gjs per year**

- **$1.10 per Gj goes to Terasen Gas Midstream MCRA**
- **$1.10 per Gj X 10,000 customers X 108 Gjs per year**

APPENDIX 6 SCHEDULE "F"

Schedule "F"
Commercial Unbundling Operational Services

TABLE OF CONTENTS

CLAUSE **PAGE**

1. DEFINITIONS 2
2. SCOPE OF SERVICES 2
3. SERVICE GUIDELINES 3
4. REPORTS 5
5. PRICING 5
6. PERFORMANCE MEASURES, DEFICIENCY CURE PERIODS AND PENALTIES 6

Schedule "F"
Commercial Unbundling Operational Services

1. DEFINITIONS

Capitalized terms that are contained in this Schedule and are not defined herein shall have the respective meanings set out in Clause 1 of the Client Services Agreement.

1.1. "Commercial Unbundling Program" shall mean a British Columbia Utilities Commission ("BCUC") approved initiative which provides large and small commercial Customers with an opportunity to purchase their gas commodity from a supplier other than Terasen.

1.2. "Marketers" shall mean a party licensed by the BCUC to contract with end use Customers to provide gas commodity.

2. SCOPE OF SERVICES

2.1. CustomerWorks agrees to provide Terasen with the following services for all Terasen's large and small commercial Customers in accordance with the policies and procedures outlined in the Protocol and as set out below for the Commercial Unbundling Program.

2.2. Generally, CustomerWorks will provide Commercial Unbundling Operational Services (the "Services") as follows:

a) Customer inquiry services related to billing and enrollment including calls related to the midstream gas components, Marketer names and phone numbers as well as participant status;
b) Customer inquiry services resulting from Terasen's Customer education campaign;
c) data capture and data transfer services related to Customer enrollments, rate changes, enrollment rejections, exception handling and rejection processing;
d) financial reporting support identifying charges directly related to the new marketer tariffs;
e) adjustment processing for retroactive rate changes resulting from Customer disputes;
f) compilation and distribution of Customer consumption history at a premise based on authorized requests from Marketers; and
g) Tariff set-up and maintenance related to the new marketer tariffs and Terasen midstream components.

3053-SCF.doc –Jan. 15, 04

Schedule "F"
Commercial Unbundling Operational Services

1. SERVICE GUIDELINES

1.1. **CustomerWorks' Responsibilities**

CustomerWorks will:

(a) perform the Services with sufficient and adequately trained staff in accordance with mutually agreeable policies and practices and sufficient to meet the service levels, all of which are set out in this Schedule and the Protocol;

(b) consult with Terasen through Terasen's co-ordinator or the co-ordinator's designate on matters related to the Services;

(c) ensure that adequate and appropriate systems, Customer contact technology and equipment are available to meet the service levels; and

(d) provide reasonable access to Terasen for monitoring purposes on request.

1.2. **Terasen' Responsibilities**

Terasen will:

(a) be responsible for pre-validating transaction files and will own the relationship with Marketers and be responsible for all Marketer related communications with CustomerWorks;

(b) provide timely notification of changes to the requirements for Commercial Unbundling or the parameters used to determine pricing; and

(c) provide timely information and decisions on the Commercial Unbundling Program and related business process issues.

1.3. **Program Assumptions**

(a) Only existing large and small commercial Customers on Rates 2, 3, and 23, within the Lower Mainland, Inland and Columbia divisions, are eligible to participate in the Commercial Unbundling Program, excluding propane customers in Revelstoke;

(b) The initial Commercial Unbundling Program customer billing start date will be November 1, 2004. Subsequently, the Commercial

3053-SCF.doc –Jan. 15, 04

Schedule "F"
Commercial Unbundling Operational Services

Unbundling Program will support quarterly entry dates beginning in May 2005;

(a) Marketers will be required to maintain a 24/7 telephone service to support Customer inquiries related to Marketer provided rates and contract terms as well as advising of appropriate emergency contact procedures;

(b) Marketers will be limited to one rate change annually per pricing option; and

(c) CustomerWorks will not handle disputes between Customers and Marketers.

1.2. **Service Levels**

a) Terasen will receive monthly reporting of complaints directly related to the Commercial Unbundling Program;

b) CustomerWorks will report monthly financial information by Tariff class in accordance with the timelines as established by Terasen and as set out in the Protocol;

c) Enrolment transactions and rejection responses will be processed each business day;

d) Customer correspondence related to the Commercial Unbundling Program will be responded to within four (4) business days of receipt;

e) Exceptions will be processed within three (3) business days; and

f) Authorized Marketer requests for consumption history will be processed within five (5) business days of receipt.

1.3. **Policies and Practices**

1.3.1 CustomerWorks shall deliver the Commercial Unbundling Operational Services in accordance with the Protocol.

3053-SCF.doc –Jan. 15, 04

Schedule "F"
Commercial Unbundling Operational Services

1.1.1 Terasen will:

(a) retain final approval rights for scripts, training materials and other materials for any Customer communications including approval of delivery method or channel;

(b) retain the right to monitor call quality.

2. REPORTS

CustomerWorks shall provide all management reports to Terasen in accordance with the Protocol which may be amended, from time to time.

3. PRICING

3.1. CustomerWorks will provide the Services described in this Schedule for three (3) years at the fees set out in the following table:

	2004	2005	2006
Commercial Unbundling Operational Services – Base Fees (excluding IT Sustainment)	$ 28,996	$ 31,632	$ 31,632
Enrolment Exception Transaction – per occurrence	$ 23.70	$ 23.70	$ 23.70
Marketer Group Set-up Request – per group	$1,776	$1,776	$1,776
Marketer Rate Change Request – per rate change per group	$ 91	$ 91	$ 91
Request for Customer consumption information – per request	$ 30	$ 30	$ 30

Note: Base fees will be billed monthly. Transactional fees will be billed monthly as incurred.

3053-SCF.doc –Jan. 15, 04

Schedule "F"
Commercial Unbundling Operational Services

The base and variable fees are based on the following assumptions related to market participation and the program assumptions described in section 3.3 of this schedule.

a) Two Marketers are expected to participate in the first year of the program, each offering two pricing options. In the next two years participation is expected to increase to four additional Marketers each offering four pricing options; and

b) The number of enrolment requests is expected to be 10,000 requests per year with an exception handling rate of 15% in the first year and decreasing to 10% in the two following years.

1. PERFORMANCE MEASURES, DEFICIENCY CURE PERIODS AND PENALTIES

The performance Measures, Deficiency Cure Periods and Penalties set out in Schedule "A" and Schedule "B" shall apply.

Note: For the first ninety (90) days after the midstream charges are shown separately on commercial bills, any billing accuracy errors that are directly attributable to the calculation or presentment of these charges will be exempt from the calculation of billing accuracy for penalty determination purposes. In addition, for the first ninety (90) days after the start of billing Marketer tariffs in November 2004, any billing accuracy errors that are directly attributable to the calculation or presentment of these charges will be exempt from the calculation of billing accuracy for penalty determination purposes.

7. TERMINATION OF SCHEDULE "F"

Notwithstanding Clause 3.4 of the Client Services Agreement, the parties agree that Terasen may terminate this Schedule upon thirty (30) days written notice with no penalties or damages. All costs, reasonably and directly incurred by CustomerWorks related to the Commercial Unbundling Operational Services, shall be paid by Terasen.

3053-SCF.doc –Jan. 15, 04

APPENDIX 7 SCHEDULE "G"

Schedule "G"
Stable Rate Program Operational Services

TABLE OF CONTENTS

CLAUSE **PAGE**

1. DEFINITIONS.. 1
2. SCOPE OF SERVICES.. 1
3. SERVICE GUIDELINES.. 2
4. REPORTS.. 4
5. PRICING.. 4
6. PERFORMANCE MEASURES, DEFICIENCY CURE PERIODS AND PENALTIES...... 5

Schedule "G"
Stable Rate Program Operational Services

1. DEFINITIONS

Capitalized terms that are contained in this Schedule and are not defined herein shall have the respective meanings set out in Clause 1 of the Client Services Agreement.

1.1 "Stable Rate" or "Stable Commodity Rate" shall mean a gas commodity rate established as a fixed annual rate and offered by Terasen as an alternative to the standard rate.

1.2 "Stable Rate Program" shall mean a British Columbia Utilities Commission ("BCUC") approved initiative which provides residential Customers with an opportunity to select a gas commodity purchase alternative that guarantees the price of the commodity for a one year term.

2. SCOPE OF SERVICES

2.1. CustomerWorks agrees to provide Terasen with the following services for all Terasen's residential Customers in accordance with the policies and procedures outlined in the Protocol and as set out below for the Stable Rate Program.

2.2. Generally, CustomerWorks will provide Stable Rate Operational Services ("Services") as follows:

a) Customer inquiry services resulting from Terasen's Customer education campaign;

b) Customer inquiry services related to program enrolment, rejections, participation requirements and billing of the new stable rate tariff ;

c) data capture services related to processing Customer enrollment requests, rejection processing, rate change processing and exception handling;

d) confirmation services to provide Customers with written notice of their acceptance or rejection status at the time of enrolment;

e) data update services related to the reversion of Customers to the standard offering in response to Customer requests;

f) reporting of Stable Rate metrics related to customer participation;

Schedule "G"
Stable Rate Program Operational Services

a) financial reporting support identifying charges directly related to the stable rate Tariff; and

b) Tariff set-up and maintenance related to the new Stable Rate option.

1. SERVICE GUIDELINES

1.1. CustomerWorks' Responsibilities

CustomerWorks will:

(a) perform the Services with sufficient and adequately trained staff in accordance with mutually agreeable policies and practices and sufficient to meet the service levels, all of which are set out in this Schedule and the Protocol;

(b) consult with Terasen through Terasen's co-ordinator or the co-ordinator's designate on matters related to the Services;

(c) ensure that adequate and appropriate systems, Customer contact technology and equipment are available to meet the service levels; and

(d) provide reasonable access to Terasen for monitoring purposes on request.

1.2. Terasen's Responsibilities

Terasen will provide:

(a) timely notification of changes to the requirements for the Stable Rate Program or the parameters used to determine pricing; and

(b) timely information and decisions on the Stable Rate Program and related business process issues.

Schedule "G"
Stable Rate Program Operational Services

1.1. **Program Assumptions**

(a) Only existing Terasen Gas residential Customers on Rate 1, within the Lower Mainland, Inland and Columbia divisions, are eligible to participate in the Stable Rate Program, excluding propane customers in Revelstoke.

(b) There will be only one Stable Rate alternative available within each Terasen operating division.

(c) The Stable Rate Option Program customer billing start date will be January 1, 2005 and will run for one year. A one year optional extension is anticipated.

(d) The stable rate Tariff will remain unchanged during the term of the Stable Rate Option Program.

1.2. **Service Levels**

(a) Customer enrollments and confirmation / rejection letters will be processed within five (5) business days of receipt unless exceptions occur, in which case the transaction will be processed within (6) business days.

(b) Cancellation requests in response to confirmation letters will be processed within five (5) business days of being advised by customers.

(c) Customer correspondence related to the Stable Rate Program will be responded to within four (4) business days of receipt;

(d) All enrollment / rejection transactions will be captured in the customer information system for tracking and audit purposes.

(e) CustomerWorks will report monthly financial information by Tariff class within the timelines as established by Terasen and as set out in the Protocol.

(f) All Customer requested removals from the Stable Rate Option will be processed within five (5) business days of receipt.

Schedule "G"
Stable Rate Program Operational Services

1.1. **Policies and Practices**

(a) Customer issue management shall be dealt with in accordance with Schedule "A".

(b) CustomerWorks shall deliver the Stable Rate Program Operational Services in accordance with the Protocol.

(c) Terasen will:

(i) retain final approval rights for scripts, training materials and other materials for any Customer communications including approval of delivery method or channel; and

(ii) retain the right to monitor call quality.

2. REPORTS

CustomerWorks shall provide all management reports to Terasen in accordance with the Protocol which may be amended, from time to time.

3. PRICING

3.1. CustomerWorks will provide the services described in the Schedule for three (3) years at the fees set out in the following table:

	2004	2005	2006
2005 Stable Rate Program – Base Fees	$ 36,600	$ 73,200	
Stable Rate Enrolment Transaction – per occurrence	$ 26.00	$ 26.00	
Optional 2006 Stable Rate Program – Base Fee		$ 50,580	$ 101,160
Stable Rate Enrolment Transaction – per occurrence		$ 30.00	$ 30.00

Note: Base fees will be billed monthly. Transactional fees will be billed monthly as incurred.

Schedule "G"
Stable Rate Program Operational Services

The base and variable fees are based on the following assumptions related to market participation and the program assumptions described in section 3.3 of this schedule.

a) The base and variable fees are based on the assumption that participation will not exceed 20,000 enrollments in each of the two years of the Stable Rate Program.

6. PERFORMANCE MEASURES, DEFICIENCY CURE PERIODS AND PENALTIES

The performance measures, deficiency cure periods and penalties shall be in accordance with those set out in Schedules "A" and "B".

7. TERMINATION OF SCHEDULE "G"

Notwithstanding Clause 3.4 of the Client Services Agreement, the parties agree that Terasen may terminate this Schedule upon thirty (30) days written notice with no penalties or damages. All costs, reasonably and directly incurred by CustomerWorks related to the Stable Rate Program Operational Services, shall be paid by Terasen.