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April 8, 2011

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. ("FEI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI")[1] (collectively the "Companies")
Price Risk Management Review of Objectives and Hedging Strategy and FEI 2011-2014 Price Risk Management Plan ("PRMP")

Response to the Commercial Energy Consumers Association of British Columbia ("CEC") Information Request ("IR") No. 2

On January 27, 2011, the Companies filed the Application as referenced above. On April 4, 2011, the CEC issued IR No. 2. In accordance with Commission Order No. G-23-11 setting out the Regulatory Timetable for the review of the Application, the Companies respectfully submit the attached response to response to CEC IR No. 2.

If there are any questions regarding the attached, please contact the Mike Hopkins at (604) 592-7842.

Yours very truly,

FORTISBC ENERGY INC.

Original signed by: Shawn Hill

For: Diane Roy

Attachment

cc (e-mail only): Erica Hamilton, Commission Secretary
Registered Parties

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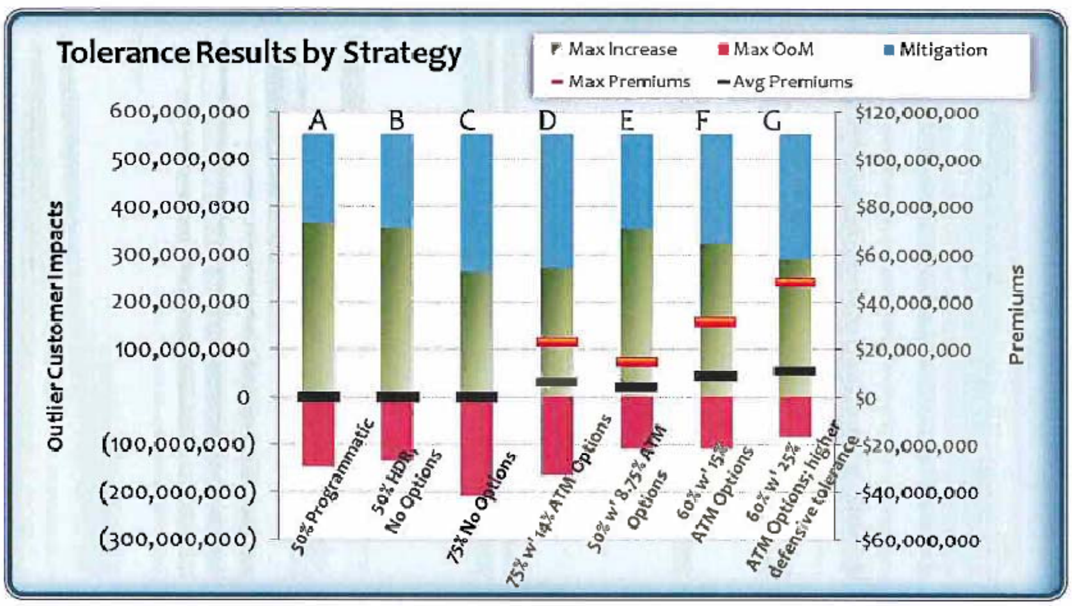
[1] Formerly Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. respectively.

1. Reference: Exhibit B-1, Page 2 & Appendix A, Risk Centrix Report, Page 6 & Exhibit B-5, CEC 1.1 to CEC 1.4

for customers. Within the report, consideration of the use of storage and deferral account balances, which mitigate rate volatility to some degree, has also been included. The Company has focused on the importance of the value of price risk management for customers, balancing rate volatility mitigation and competitiveness with reducing the potential costs of hedging. In consultation with Commission staff, an external consultant with extensive experience with utility price risk management, was used for this review. The consultant's review and recommendations are included in this report.

Figure 11, Strategy Assessment Results



1.1 Please confirm that what FEU is asking for Commission approval on, would (1) increase expected average premium costs by about $10,000,000, per year (2) increase exposure to higher premium costs up to about $50,000,000 per year (3) reduce outlier customer impacts by about $100,000,000 per year and (4) reduce out of the money exposure by about $60,000,000 per year. Is that a correct reading of the strategy results being sought?

Response:

The proposed hedging strategy being requested could produce results in the order of the amounts being presented in Table 18 on page 88 of Section 7.1.3 of the Review Report. As discussed in this section, the consultant RiskCentrix performed analysis with respect to several different hedging strategies under several different market price scenarios to help determine potential cost mitigation amounts, out-of-market costs and option premium costs. Ultimately, market price movements may not exactly reflect these scenarios. Strategy G in Table 18 represents the recommended hedging strategy by FEI. In comparison to a more programmatic-based hedging strategy, such as Strategy A which represents the previous hedging strategy used by FEI, the outcomes for the recommended strategy could result in the following changes under different market price conditions:

- Incremental commodity cost mitigation of about $75 million per year
- Incremental out-of-market cost reduction of about $64 million per year
- Incremental average option premium costs of about $11 million per year
- Maximum incremental option premium costs of about $48 million per year

It is important to note that the option premium costs are included in the portfolio cost and out-of-market outcomes as presented in Table 18 so they do not need to be added.

It is also important to note that these outcomes regarding costs and mitigation are based on simulated market pricing scenarios and may not actually occur. For example, if market prices and volatility do not increase such that defensive tolerances are breached, then no option premium costs would be incurred.

1.2 Please provide a probability risk distribution to the higher premium costs up to the $50,000,000.

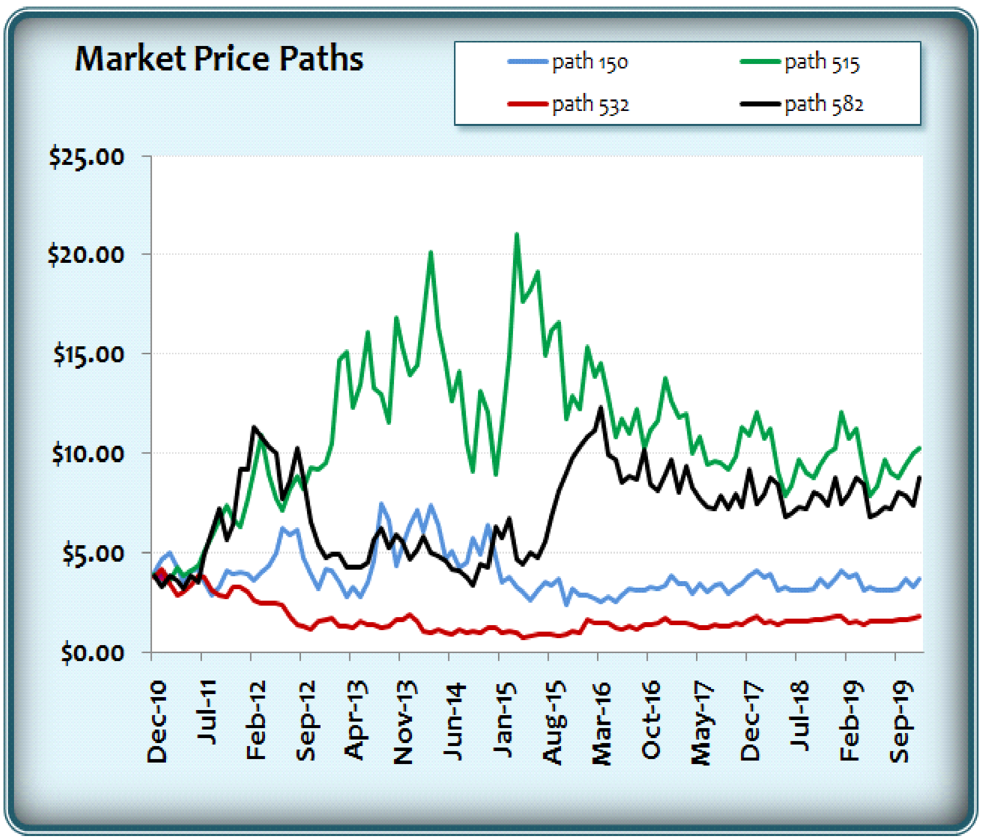
Response:

As discussed in the response to the previous CEC IR 2.1.1, the consultant RiskCentrix performed analysis regarding several representative market price scenarios. As such, a probability risk distribution to the higher premium costs up to the $48 million is not available. However, the average and maximum option premium costs for each of these market price scenarios are available (per Appendix 1 of Appendix A of the Review Report) and provided in Table 1 below.

Table 1: Premiums Costs Under Different Price Scenarios

	Average Premiums	Maximum Premiums
High Cycle	$ 13,128,457	$ 37,870,476
Very High	$ 22,029,340	$ 48,343,979
Very Low	$ 1,226,118	$ 9,405,451
Mid Cycle	$ 7,780,230	$ 19,729,282

The four representative price scenarios used by RiskCentrix per page 16 of Appendix A of the Review Report, are provided below.



Number	Name	Desciption
Path 582	High Cycle	Periods of mid-level prices with extreme price increases and decreases
Path 515	Very High	Sustained high prices
Path 532	Very Low	Sustained low prices
Path 150	Mid Cycle	Periods of low prices with moderate price increases and decreases

As discussed in the response to the previous CEC IR 2.1.1, the options would only be implemented if market prices and volatility increased such that defensive tolerances were breached and as part of the defensive hedging strategy.

1.3 Please provide a probability risk distribution around the expected reduced outlier customer impact and around the expected outlier customer impact.

Response:

As discussed in the response to the previous CEC IR 2.1.2, the consultant RiskCentrix performed analysis regarding several representative market price scenarios. As such, a probability risk distribution around the expected reduced outlier customer impact and around the expected outlier customer impact is not available. However, the expected reduced outlier customer impact with Strategy G versus Strategy A (i.e. incremental cost mitigation) and expected outlier customer impact of Strategy G (i.e. cost mitigation) for each of these market price scenarios are available (per Appendix 1 of Appendix A of the Review Report) and provided in Table 1 below.

Table 1: Expected Customer Bill Mitigation

	Cost Mitigation	Incremental Cost Mitigation
High Cycle	$228,422,134	$95,808,871
Very High	$261,054,470	-$8,531,173
Very Low	$31,226,622	-$645,014
Mid Cycle	$98,099,237	-$9,420,927

2. Reference: Exhibit B-5, CEC 1.2 & BCUC 1.8.3 & BCOAPO 1.2.1

For FEI, gas deferral accounts and the quarterly rate adjustment mechanism, and the Equal Payment Plan ("EPP") compliment the hedging program in moderating rate impacts for customers. The two gas cost deferral accounts utilized by FEI include the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA") as discussed in Section 5 of the Review Report. These deferral accounts capture variances between the actual gas costs and the forecast gas costs as recovered in rates and the deferral mechanisms, which are reviewed quarterly enable these variances to be recovered from, or refunded to, customers as part of future rates forecast over a twelve month period. These deferral accounts ensure that 100% of the actual gas costs are borne by customers, including any costs above or lower than those forecast. Currently, FEI uses a quarterly rate adjustment review mechanism to effectively manage the deferral account balances from becoming too large, as well as providing appropriate price signals. Significantly high deferral account balances can impact FEI's financial borrowing capacity and ultimately its risk profile, as discussed in Section 5.1 of the Review Report. Furthermore, these deferral accounts do not affect or help manage the underlying commodity prices embedded in the cost of gas, which will eventually flow through to customers. The hedging program, on the other hand, does impact the underlying commodity prices and so directly manages gas costs.

Reference: BCUC 1.8.3

2.1 Have the FEUs determined quantitatively what these other mechanisms contribute to reducing customer experienced volatility?

Response:

Please refer to responses to BCOAPO IRs 1.2.1, 1.2.2, and 1.2.4.

2.2 Have the FEUs determined quantitatively what the relative contribution of the proposed hedging program and the other volatility reduction mechanism is?

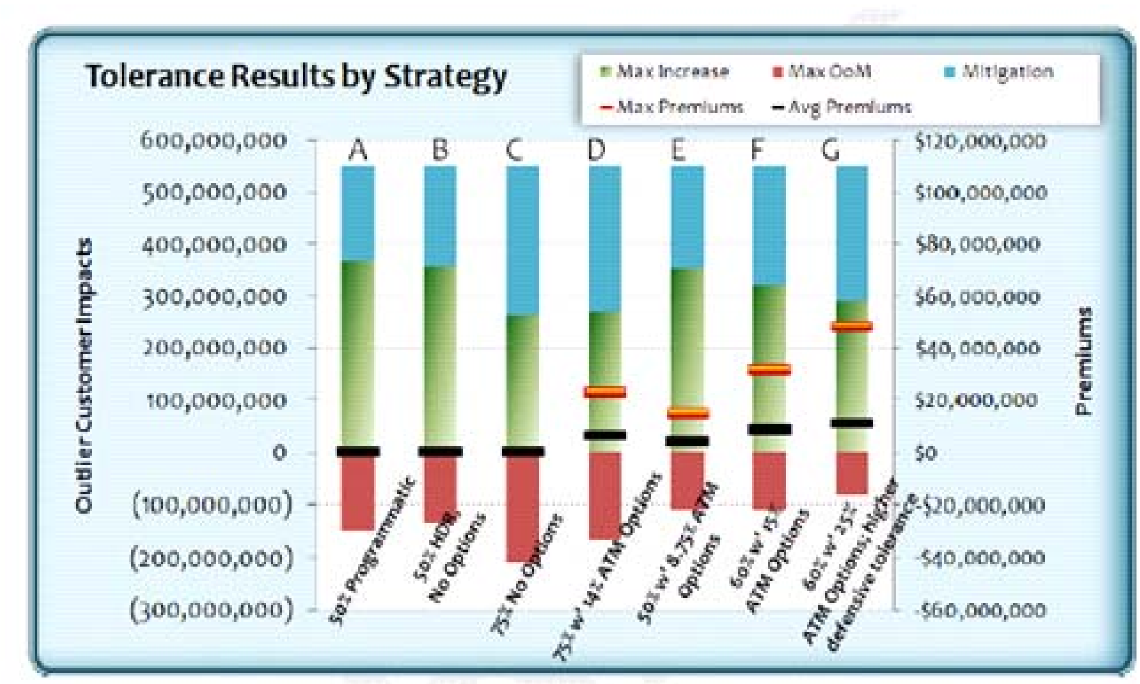
Response:

The Companies do not have a way to measure expected total bill volatility with and without hedging in its portfolio for the future because of uncertainty regarding where future prices may eventually settle.

However, the most relevant metrics to measure potential outcomes of various scenarios were performed by the RiskCentrix consultant. Table 18 on page 88 of the Review Report, also shown below, performed analysis of different hedging scenarios under different simulated market price conditions, for both high and low price environments, in order to determine appropriate ranges for expected bill volatility and costs based on a 95% confidence interval.

The graph shows the maximum expected volatility reduction and bill increase and maximum out-of-the market costs and option premium expenditures. Without hedging, the bill increases would be the full columns in the graph and hedging and options costs would be zero. FEI is recommending strategy G as the optimal balance of meeting the primary objectives of the PRMP and minimizing potential hedging costs. Further details of the RiskCentrix analysis can be found in Appendix A of the Review Report.

Figure 1: Hedging Strategy Scenario Results



The Companies do not have quantitative analysis to predict total bill volatility reduction from the CCRA deferral account and rate setting methodology. It is the Companies' view that gas cost deferral account and rate setting mechanisms work in conjunction with a hedging program to provide volatility reduction, however only hedging provides protection for the underlying gas costs in the portfolio.

2.3 Have the FEUs determined quantitatively what the relative contribution of past hedging program and the other volatility reduction mechanisms is?

Response:

Please refer to the responses to BCOAPO IRs 1.2.1, 1.2.2, and 1.2.4.

2.4 Please provide a quantitative analysis of the relative contributions of the hedging programs and the other volatility reducing mechanism.

Response:

Please refer to the responses to CEC IRs 2.2.1, 2.2.2, and 2.2.3.

2.5 Have the FEUs determined what the optimum mix of its hedging and its other volatility reducing mechanisms would be?

Response:

Please refer to Section 8 of the Review Report for a complete summary of the proposed enhanced hedging program.

In terms of EPP, this is a completely voluntary option that is available to customers.

In terms of the CCRA deferral account and rate setting mechanism, FEI will continue to report deferral balances and propose changes, as appropriate, to customer rates to the Commission on a quarterly basis, consistent with the existing Commission guidelines. Also please refer to the response to CEC IR 2.3.1.

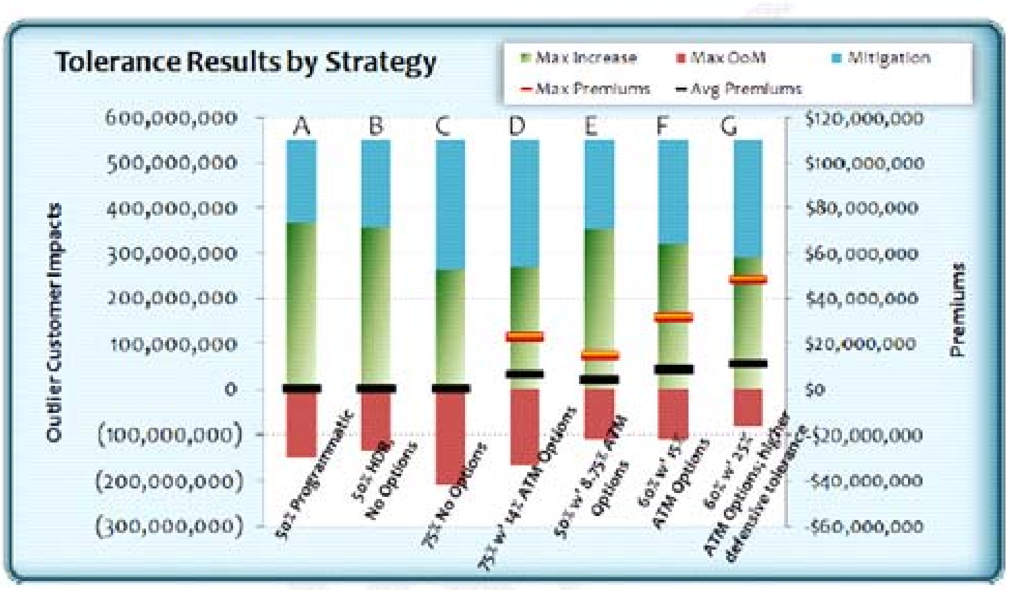
2.6 Please provide a quantitative analysis supporting a view on what the optimum mix of hedging and other volatility reducing mechanisms would be.

Response:

The consultant RiskCentrix recommended various strategies, as discussed in Section 7.1.3 of the Review Report and as summarized in Figure 1 below. Table 18 on page 88 of the Review Report performed analysis of different hedging scenarios under different simulated market price conditions in order to determine some ranges for expected bill volatility and costs based on a 95% confidence interval. The figure shows the maximum expected volatility reduction and bill increase and maximum out-of-the market costs and option premium expenditures. Without hedging, the bill increases would be the full columns in the graph and hedging and options costs would be zero.

FEI is recommending strategy G, from the figure below, as the optimal balance of meeting the primary objectives of the PRMP and minimizing potential hedging costs. Further details of the RiskCentrix analysis are provided in Appendix A of the Review Report.

Figure 1: Hedging Strategy Scenario Results



Please refer to the responses to CEC IRs 1.49.1 and 2.3.1 which relate to the deferral account process and rate setting mechanism.

3. Reference: Exhibit B-5, CEC 1.8.2

As discussed in Section 4.5.1 and 4.5.1.2 of the Review Report, customers have indicated that they are willing to tolerate a certain acceptable amount of volatility in their rates but also prefer rate stability as well. FortisBC believes that increasing the number of potential rate changes will lead to outcomes not preferred by customers as indicated in various surveys and focus groups.

FortisBC believes that deferral account balances and EPP should be complementary to an effective hedging program that strives to manage the underlying volatility inherent in market prices.

3.1 If fewer price adjustments would be preferable in the rates has FEI modeled deferral accounts for managing price volatility, which would be designed to operate in a 50%/50% over/under pricing range, with that range being reset periodically?

Response:

FEI has not specifically modelled a rates setting methodology in which rate changes would be triggered under a ± 50% pricing range. The current, Commission established CCRA rate setting methodology utilizes a ± 5% recovery-to-cost range for the 12-month prospective rate setting period. Prior to 2001, gas cost recovery rates were established once per year effective January 1 based on forecast costs for the upcoming year. However, during 1999 and 2000 gas costs were much higher than forecast and even with mid-year rate increases the gas cost deferral account (then called the Gas Cost Reconciliation Account or "GCRA") balance moved from a net credit balance to a net deficit balance of about $180 million by the end of 2000.

Large deferral balances should be avoided from both a Company and a customer perspective. A large deficit deferral balance such as the GCRA balance at the end of 2000 would likely require the Company to increase its credit capacity in order to manage its monthly working capital requirements, and can impact the Company's financial risk profile as the larger deferral balance could lead to an increase in probability of loss on payment of amounts owed. Further, large deferral balances will likely result in the need for larger rate changes to be flowed through to customers and send incorrect price signals to customers which can cause perverse customer behaviours such as customer migration from the Utility sales rate offerings, or from gas service entirely. As a result of the experiences in 2000, in February 2001, the Commission issued its Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balances (the "Guidelines").

The Guidelines currently apply for the FEI Commodity Cost Reconciliation Account ("CCRA") and Midstream Cost Reconciliation Account ("MCRA"). On March 10, 2011, FEI filed a review report on the CCRA and MCRA Deferral Accounts and Rate Setting Mechanisms (the "Report").

Within the Report, FEI provided the results of its analysis of a number of alternative rate adjustment mechanisms using historical data.

The Company believes the results of its review validate that the current CCRA and MCRA quarterly review and rate setting mechanisms, consistent with the Commission established

Guidelines, have functioned appropriately up to now and FEI has recommended only minor changes be made to the existing Guidelines. With respect to commodity rates and the CCRA, the Company believes that the following two minor changes will serve to further improve the quarterly review and commodity rate setting mechanism, thereby benefiting customers through reduction of the frequency of minor rate changes while still providing appropriate price signals and management of the deferral balance:

1. Commodity Price Forecasts – the Company supports the continued use of the NYMEX natural gas commodity futures, and believes that a multi-day average is preferable to a single forward strip date. FEI recommends that a five-day average of forward prices taken on consecutive market dates be utilized in the determination of the gas cost forecasts for the quarterly review and resetting of rates. The use of a five-day average will provide an appropriate mechanism that reduces the forecast price variability while still providing an average price that reflects current market conditions.
2. CCRA Deferral Account and Rate Setting Mechanism – the Company supports the continued use of the existing ± 5% trigger ratio, and recommends the addition of a secondary parameter of a minimum $0.50/GJ rate change threshold value to enhance the effectiveness of the trigger mechanism utilized to evaluate the appropriateness of the commodity cost recovery rate on a quarterly basis. The Company believes this will continue to provide a balance of maintaining manageable deferral balances and providing appropriate price signals to customers, while avoiding minor CCRA rate changes in low price environments.

The Commission under Commission Letter No. L-20-11, dated March 22, 2011 (electronic version only provided in Attachment 3.1), has invited parties with an interest in the matter to submit written comments on the recommended changes.

It is FEI's view that the CCRA and MCRA deferral account and rate setting mechanisms are appropriate, and that the deferral account and rate setting mechanisms work in conjunction with a hedging program. FEI further notes that while both deferral account and rate setting mechanisms and hedging provide rate stability, only hedging provides protection for the underlying gas costs in the portfolio.

3.2 Could FEI propose such a pricing and deferral account management approach and if not why not?

Response:

Please refer to the response to CEC IR 2.3.1.

3.3 Please model a deferral account approach to managing volatility for the period shown in Figure 1, using a price of, $12/GJ, $12.25/GJ, $12.50/GJ and $12.75/GJ and show the account balance which would have occurred.

Response:

Please refer to the response to CEC IR 2.3.1.

The current, Commission established CCRA deferral account and rate setting methodology utilizes a ± 5% recovery-to-cost range for the 12-month prospective rate setting period. Changes to the underlying forecast cost of natural gas will affect the deferral account balances and the value of the commodity rate that would have to be set to recovery the gas costs. For example, if the long-term cost of gas was to increase to $12.00/GJ to $12.75/GJ, the commodity rate would ultimately need to increase to recover the costs. Based on the approved ± 5% recovery-to-cost deadband range and an estimated annual CCRA volume of approximately 100 PJ, the CCRA deferral balance at the end of any 12-month prospective period could fall between a $60 million surplus and a $60 million deficit range at the $12/GJ level, to a $63.75 million surplus and a $63.75 million deficit range at the $12.75/GJ level – deferral balance falling outside those ranges would trigger a rate change.

3.4 Please advise what financing costs would have been applicable to the deferral account balances in the scenarios proposed above.

Response:

FBU's short term cost of debt would be applicable to such scenarios. Should the size of the deferral account balances increase such that the Company would need to increase its credit capacity, FBU would be subject to renewal or amendment costs as well as re-pricing of the applicable margin imbedded in its short term cost of debt on its credit facilities.

Also please refer to the response to CEC IR 1.49.2.

3.5 Please propose what would be reasonable deferral account management rules for such scenarios as are proposed above and advise how frequently prices would have needed to be changed to meet the criteria proposed.

Response:

Please refer to the response to CEC IR 2.3.1.

4. Reference: Exhibit B-5, CEC 1.8.3

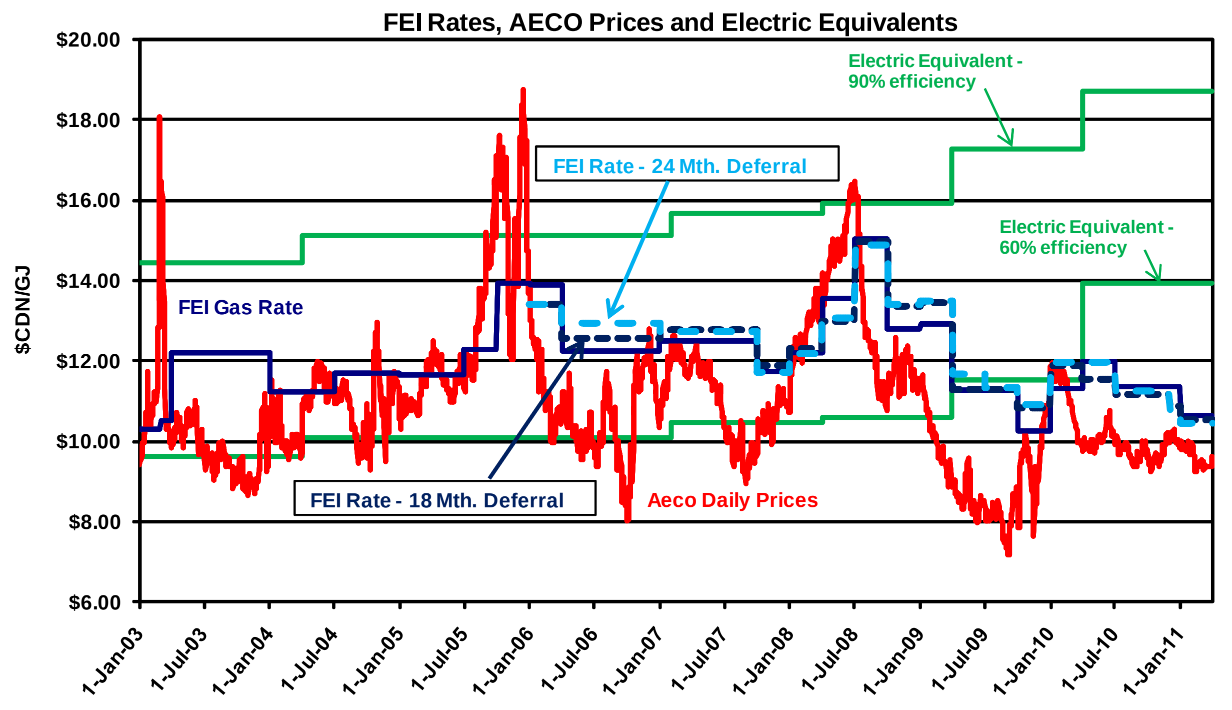
The graph shown in Figure 1 in Section 2.4.1 of the Review Report has been revised, and attached below, to include (1) a line to provide a proxy of what the FEI rate would have been if the commodity recovery component of rates had been set based on an 18-month prospective

basis, and (2) a line to provide a proxy of what the FEI rate would have been if the commodity recovery component of rates had been set based on a 24-month prospective basis.

4.1 Please provide the graphs referred to in the response as they were not available in the material in Exhibit B-5 available to the CEC or if they were provided and the CEC has missed them please provide direction as to where they may be found.

Response:

Below please find the graph which was inadvertently omitted from the response to CEC IR 1.8.3.



Notes: - AECO prices adjusted up by FEI fixed, basic & delivery and midstream charges for comparison purposes
- Efficiency of gas furnace is 90% (100% for electricity) and hot water heater is 60% (90% for electricity)

5. Reference: Exhibit B-5, CEC 1.20.1

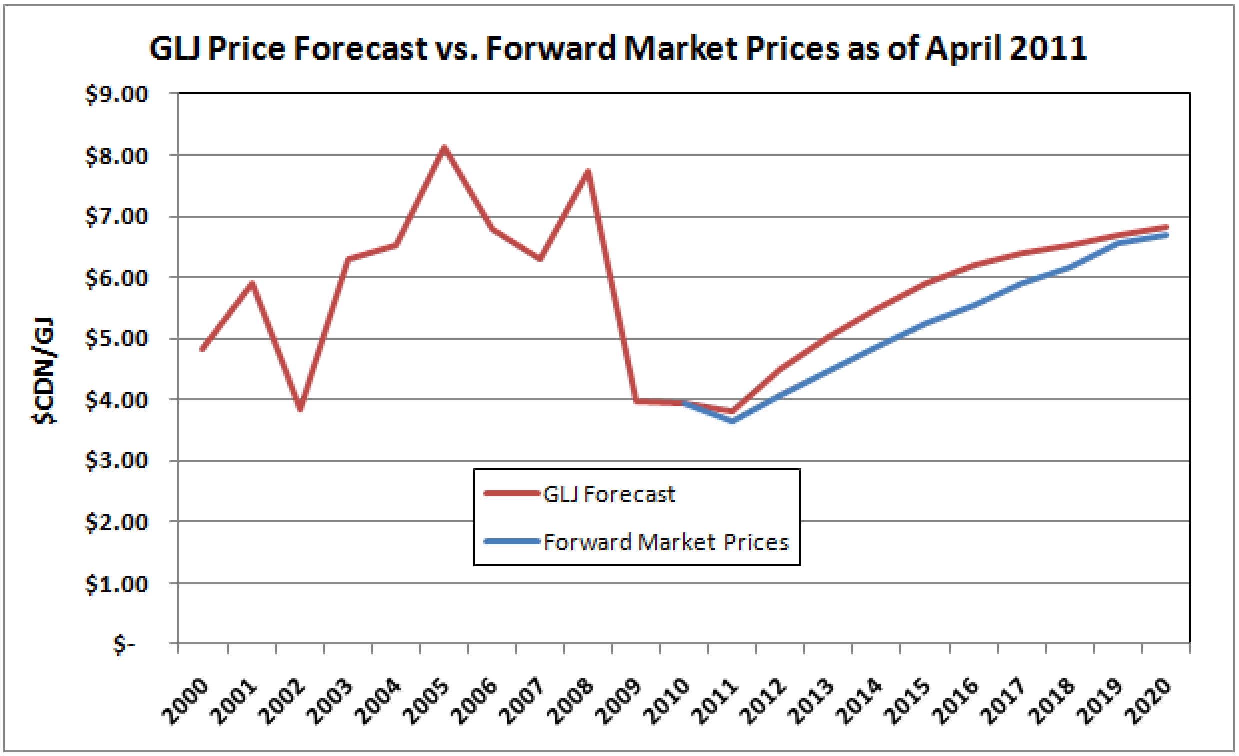
> Not necessarily, there are too many variables to make this assumption. First of all, this would require an assumption the producers can continue to manage the costs of production, environmental protection and the infrastructure required to connect to markets, and also provide an appropriate level of return on their investment. More importantly, it also assumes that there is no competition for capital between development opportunities available to these producers. For example, currently industry participants are witnessing a significant shift from natural gas development to more liquid plays in response to high oil prices.

5.1 Does FEI have any evidence that the forward prices will not represent a suitable economic environment for producers to supply natural gas at these prices?

Response:

As discussed in the Section 4.3.1 of Appendix D of the Review Report, forward natural gas market prices are below the longer term marginal cost of new supply, according to GLJ Petroleum Consultants Ltd. ("GLJ"). This does not represent a suitable economic environment for producers to supply natural gas over the long run. Figure 35 on page 46 of the Appendix shows that GLJ's forecast prices are about 25% higher than market prices as of January 1, 2011. The latest GLJ forecast and forward market prices for AECO as of April 1, 2011 are provided in the following Figure 1.

Figure 1: GLJ Price Forecast vs. Market Prices as of April 1, 2011



GLJ has not materially changed their forecast since January 1, 2011 but forward market prices have moved up since January 1, 2011 by about 15% out to 2020. This is likely in response to potential increases in future demand, a gradual shifting away of some natural gas to liquids and oil production, increased costs associated with exploration and drilling and greater environmental and regulatory oversight. However, forward prices still remain below the April 1, 2011 GLJ forecast by about 8% on average out to 2020. According to GLJ, forward market prices need to increase further to provide producers with a suitable economic environment to supply natural gas over the long run.

6. Reference: Exhibit B-5, CEC 1.23.1

In Ontario, Union Gas Limited ("Union") and Enbridge Gas Distribution Incorporated ("Enbridge") had their hedging programs effectively cancelled by their regulator in 2008 and 2007, respectively. To help with mitigating price risk, these two utilities have significant amounts of contracted storage capacity and access to the liquid Dawn market hub which reduces their need to purchase seasonal and peaking gas and take advantage of favourable priced spot gas when load requirements dictate. The large quantity of available storage capacity in Ontario is in stark contrast to the situation the Companies face in British Columbia. Storage capacity relative to overall demand in the Pacific Northwest ("PNW") region is relatively scarce and the Companies do not have the same access to storage resources as utilities have in Ontario. As a result, this can have adverse impacts on prices in the PNW region, particularly at Station 2 and Sumas during periods of high demand typically seen during colder winter months.

6.1 Please describe what if anything FEI is engaged with or plans to become engaged with that may lead to increased storage capacities in the Pacific Northwest.

Response:

FEVI is currently completing the construction of the the Mt. Hayes LNG storage facility on Vancouver Island, which will add 1.5 Bcf of storage capacity to the area and provide peaking services to both FEVI and FEI beginning in 2011. In addition, FEI contracts for storage services with the Pacific Northwest storage owners and has supported expansion projects by contracting for long term storage services at Northwest Natural's Mist storage facility and Northwest Pipeline Company's Jackson Prairie storage facility. For example, in 2006 FEI contracted for a long-term capacity addition at Jackson Prairie, which helped underpin the ongoing expansion of that facility. FEI also holds the largest amount of storage capacity at Mist, other than what NWN holds for its own customers requirements, and continues to look for longer term solutions. FEI has in the past also investigated the potential for greenfield underground storage projects in the region, however has concluded that no cost effective opportunities are available outside of limited potential for further expansions at Mist or Jackson Prairie where, securing firm redelivery of gas from the Pacific Northwest storage facilities continues to be the primary concern.

7. Reference: Exhibit B-5, CEC 1.43.2 & BCUC 1.7.1.5

Response:

The net enrolments for residential and commercial customers in the Customer Choice Program have been declining since mid 2009. During this period, natural gas market prices and FEI residential rates have declined. It is FEI's belief that this recent negative growth in enrolments is a reflection of customers not willing to pay significant premiums over market prices in order to achieve absolute rate or bill certainty. In other words, some customers are not willing to pay for rate certainty at any cost.

7.1 The FEU have offered to handle price risk management by providing hedging for all of its customers. Why have the FEU not offered to have an option for some customers who might not want the costs of hedging programs but may be satisfied simply with rate smoothing options?

Response:

Please refer to the response to BCUC IR 2.4.3.

7.2 Would the FEU be open to offering the choice to customers to avoid the hedging costs?

Response:

Please refer to the response to BCUC IR 2.4.3.

8. Reference: Exhibit B-5, CEC 1.46.1

> The Utilities believe that the proposed hedging strategy provides the appropriate balance of meeting the objectives of competiveness and rate stability while reducing the potential for significant hedging costs relative to the previous price risk management strategies. If the recommended strategy is not approved and FEI is directed to suspend its hedging activities, FEI could look to a greater amount of physical index based supply or greater use of storage capacity in the portfolio.
>
> A greater amount of unhedged index priced gas supply in the portfolio exposes customers to greater market price fluctuations. Increasing storage capacity can provide greater security and reliability of supply but also increases associated storage and transportation fixed demand charges and variable costs which are flowed through to customers in rates.
>
> Based on these considerations, the Utilities have recommended the enhanced hedging program, in combination with appropriate physical resources and effective management of deferral account balances, to meet the objectives at a reasonable cost for customers.

8.1 Do the FEU have any quantitative analysis to demonstrate the appropriate balance between physical index based supply and storage capacity capability versus the FEI proposed hedging strategy, if so please provide this?

<u>Response:</u>

No, FEU has not prepared such an analysis. The analysis of the appropriate amount of storage capacity and physical index based supply is performed independently from the development of the hedging strategy. However the development of the hedging strategy does take into account the mix of resources held in the gas supply portfolio.

As discussed in the response to BCOAPO IR 2.18.1, the Utilities assess the optimal amount of storage and other midstream and supply resources that make up the gas supply portfolio as part of the modeling performed to support the Annual Contracting Plan (ACP). The main objective of the ACP planning process is to determine the optimal balance of resources, including storage and index based supply, to cost effectively and reliably meet customers' load requirements. That analysis makes certain assumptions regarding summer winter differentials, availability and cost of storage and pipeline transportation capacity as well as a number of other factors (refer also to the response to BCUC IR 2.5.1), however generally does not take into account volatility in underlying commodity prices from unforeseen circumstances. Furthermore, the price protection associated with storage capacity is generally limited to a single season and storage injections during the summer could be impacted by any adverse market price movements.

As discussed in Section 7.1.3 of the Review Report, the consultant RiskCentrix has developed an enhanced hedging strategy that will serve to meet the objectives at a reasonable cost. This strategy includes hedging up to a maximum level of 60% of the Commodity Cost Reconciliation Account ("CCRA") hedgeable volumes. The remaining percentage of index based supply would be unhedged and subject to market price movements. This represents an appropriate balance of index based supply exposure and hedging to meet the objectives of the PRMP. Hedging more than this could increase potential out-of-market hedging costs while hedging less than this could expose customers to greater market price volatility and decrease the likelihood of remaining competitive with other sources of energy if market prices and volatility increased in the future.

Based on these considerations, the Utilities believe that the recommended enhanced hedging strategy in combination with the amount of unhedged index based supply and storage capacity provides the appropriate balance to meet the objectives of the PRMP.

9. Reference: Exhibit B-5, CEC 1.48.2

Response:

Yes. The Utilities are of the view that the current quarterly review and commodity rate setting process does provide for appropriate clearing of deferral accounts and reduces the potential for balances to climb to unsustainable levels.

9.1 Does the FEU have a quantitative analysis of what represents the appropriate account clearing rules and an analysis of alternatives to the ones being used?

Response:

Please refer to the response to CEC IR 2.3.1.

9.2 Could the FEU please provide a quantitative analysis of the appropriate account clearing rules if it does not have one?

Response:

Please refer to the response to CEC IR 2.3.1.

10. Reference: Exhibit B-5, CEC 1.49.3

Response:

FBU does not believe that higher deferral account balances offset the risks of reduction of the customer base, as the delay in flowing through gas cost increases does not fundamentally change the underlying cost of gas that may lead to a potential loss of customers. FBU believes the potential increased risks to financial risk profile related to significantly high deferral account balances would not be reasonable and it would not be prudent to allow deferral account balances to build to significant levels.

10.1 Isn't hedging really just an externalized deferral account mechanism with a 3rd party carrying the balances?

Response:

No. As discussed in the response to BCUC IR 1.8.3, deferral accounts capture variances between actual gas costs (including hedging gains or costs) and forecast gas costs (including any forecast hedging gains or costs) embedded in the recovery rates. On a quarterly basis, these variances are recovered from, or refunded to, customers as part of future rates forecast over a twelve month period. The Company manages the deferral account balances within its financial borrowing capacity.

Hedging, on the other hand, directly impacts gas costs by converting physical index exposure to fixed or capped exposure and is part of the actual and forecast gas costs, the variances of which are managed through deferral accounts. So while hedging impacts the actual and forecast gas costs, deferral accounts manage the *differences* between actual and forecast gas costs but do not directly impact them.

10.2 Isn't FEUs view of its internal deferral account prudency fundamentally at odds with its view of the hedging prudency?

Response:

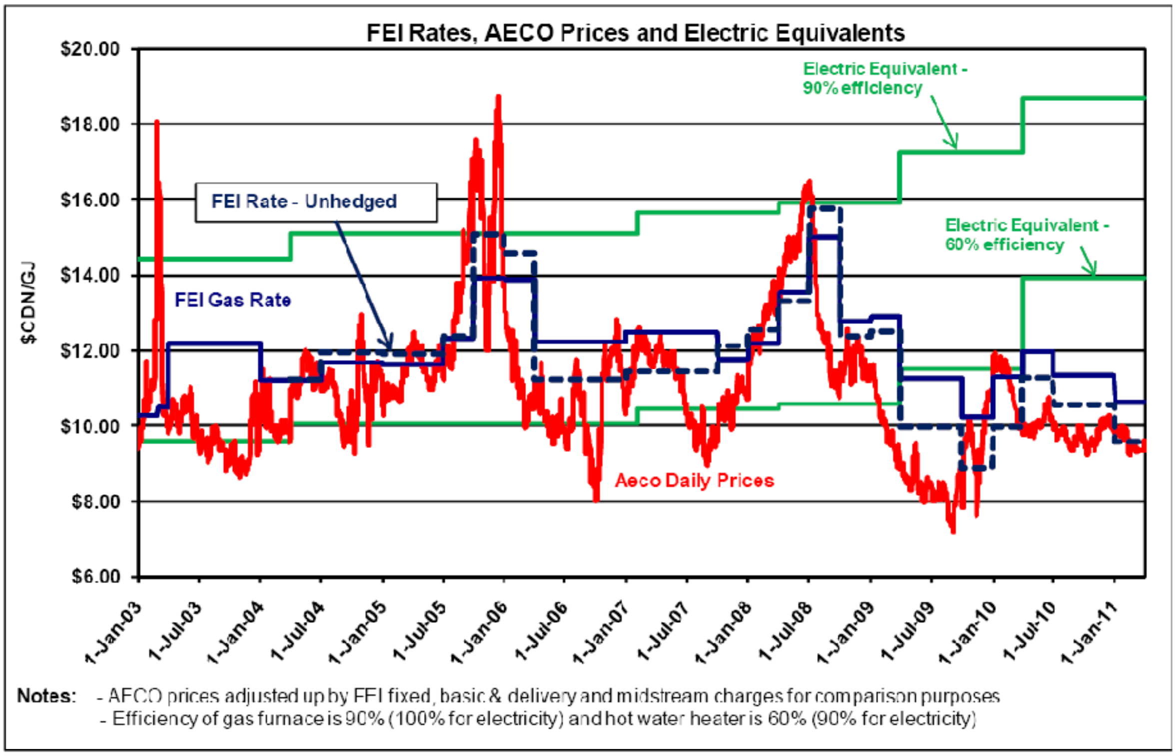
No. As discussed in section 5 of the Review Report, and in the RiskCentrix report attached as Appendix A to the Review Report, the FEI deferral account and rate setting methodology works in conjunction with an effective hedge program. Also, please refer to the response to CEC IR 1.48.1.

10.3 Does FEU have a quantitative analysis of its financial and credit costs for deferral accounts versus the costs of hedging and options programs?

Response:

No, FEU has not prepared such an analysis. As stated, the use of deferral balances serves a different function than the hedging program and there are no logical tradeoffs that could be evaluated that would provide any conclusions that are relevant in the review of the objectives of the proposed enhanced hedging program.

11. Reference: Exhibit B-4, BCOAPO 1.2.2

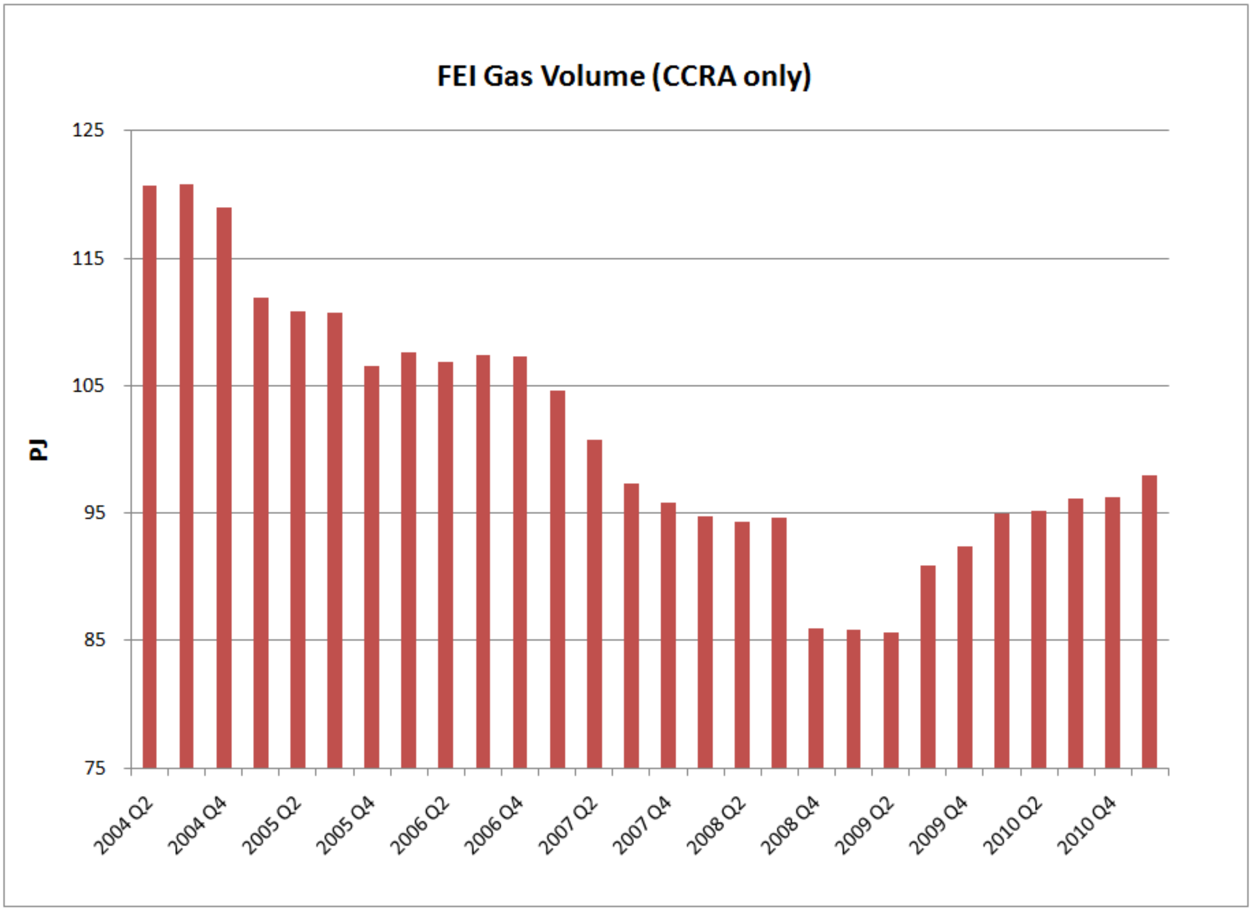


11.1 Please provide, in graphic form, the gas volumes to which the prices shown are applicable.

Response:

Figure 1 below provides the forecast CCRA volumes, upon which the commodity or CCRA rate component was determined. The delivery and midstream components of rates, which are unchanged between the two scenarios, are based on the total forecasted non-bypass customer volumes and the total forecasted core sales customer volumes, respectively.

Figure 1: Forecast CCRA 12-Month Prospective Volumes



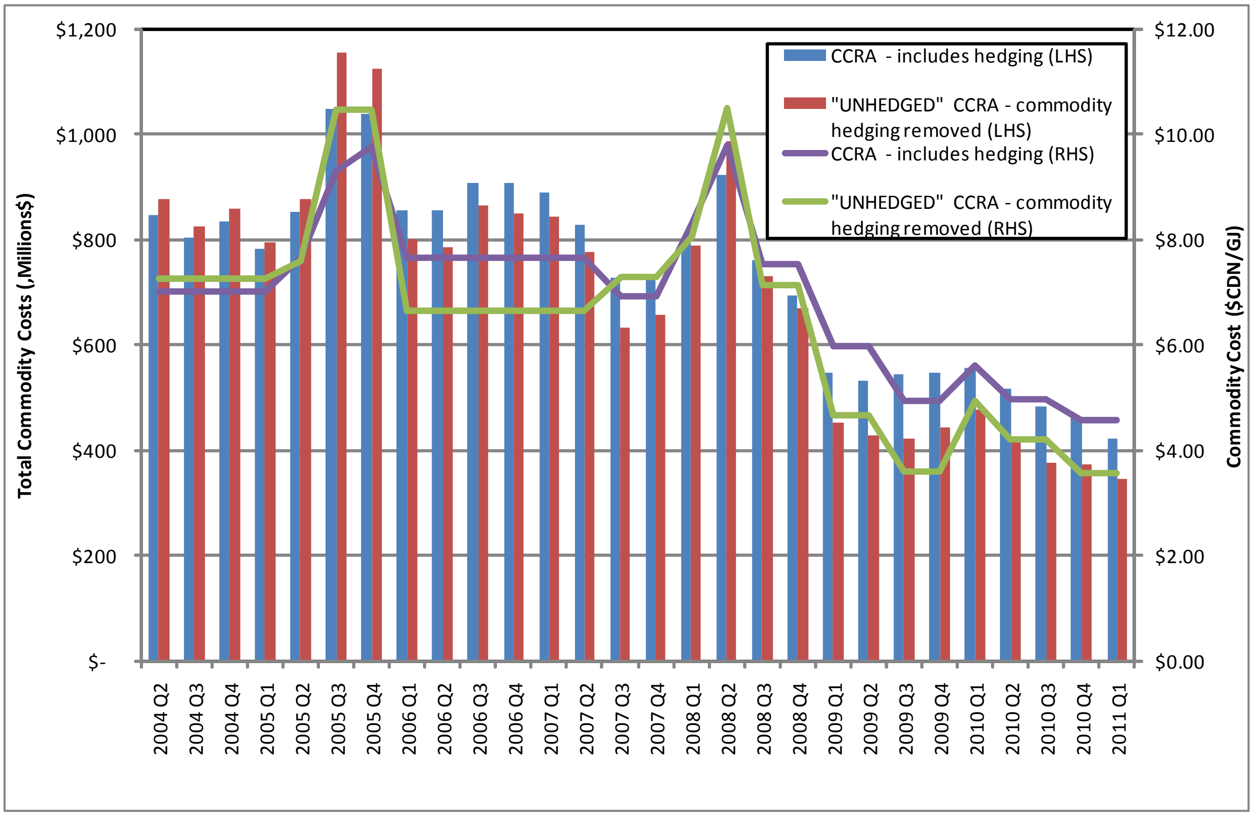
11.2 Please provide, in graphic form, the gas cost totals for the hedged and unhedged scenarios shown above.

Response:

Please find the graph requested attached below as Figure 1.

The lines shown on the graph represent the historical (hedged) CCRA rates and the calculated "unhedged" CCRA rates going back to the commencement of the Essential Service Model. As well, the bars shown on the graph represent the forecast 12-month prospective total CCRA gas costs under both the historical (hedged) quarterly rate reviews and the calculated "unhedged" scenarios.

Figure 1: Hedged CCRA Rate and Unhedged Rate Scenarios



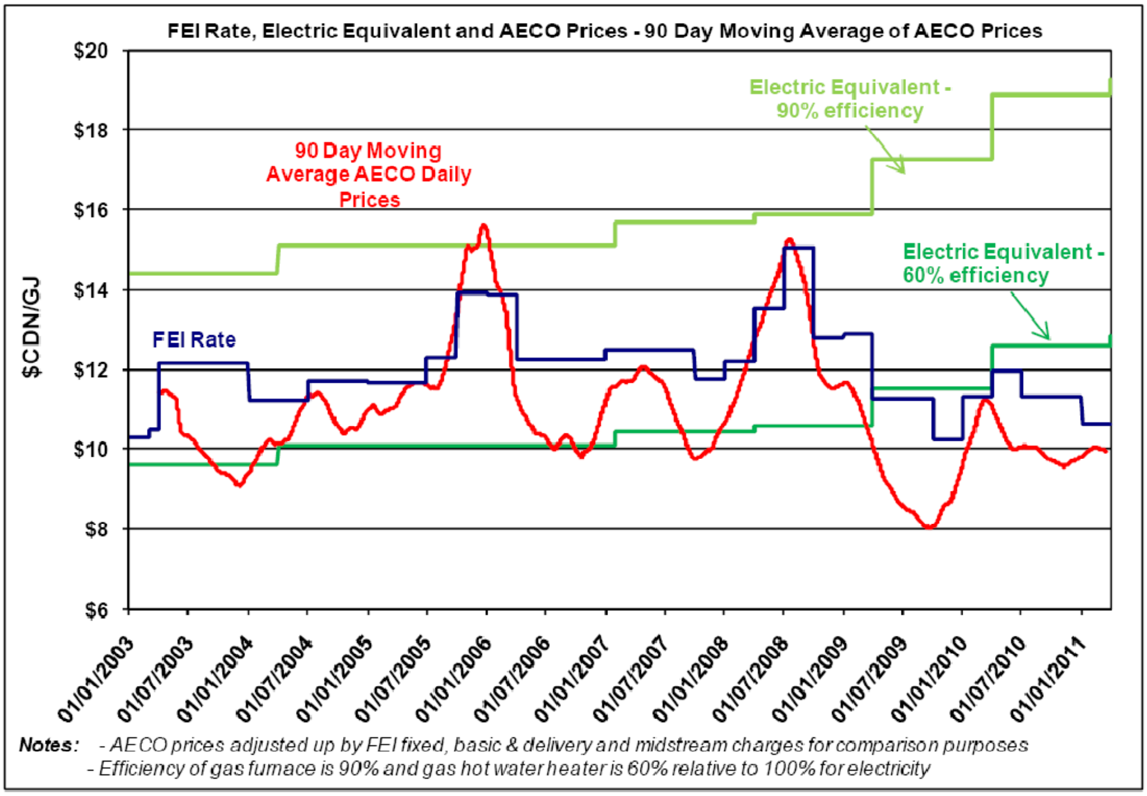
11.3 Please supply the data in spreadsheet form for the rates, gas volumes and total gas costs for the hedged and unhedged scenarios.

Response:

Attachment 11.3 includes the historical (hedged) CCRA rates and the calculated "unhedged" CCRA rates going back to the commencement of the Essential Service Model. As well, the forecast 12-month prospective gas sales volumes, and the forecast 12-month prospective total CCRA gas costs under both the historical (hedged) quarterly rate reviews and the calculated "unhedged" scenarios are included in the data table.

12. Reference: Exhibit B-3, BCUC 1.8.4

Figure 1: 90 Day Moving Average AECO Daily Price Compared to FEI Rate and Electric Equivalents

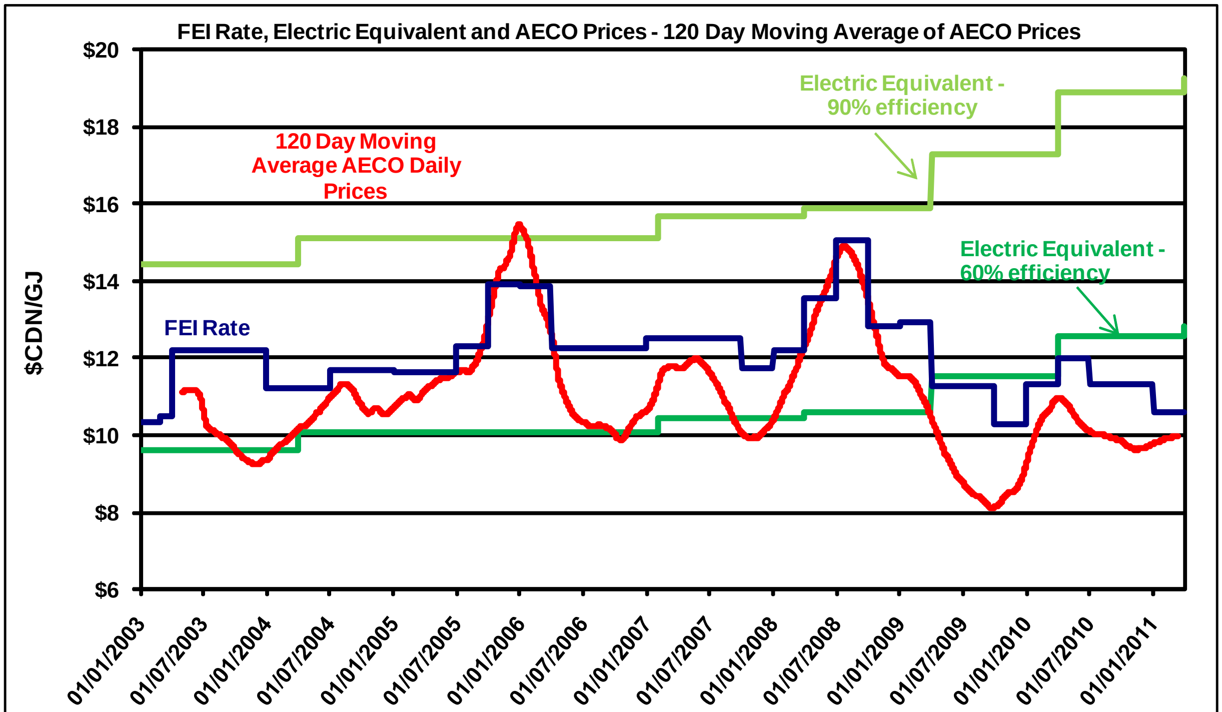


12.1 Please provide a 120, 180, 360 day moving average in the same graphic form.

Response:

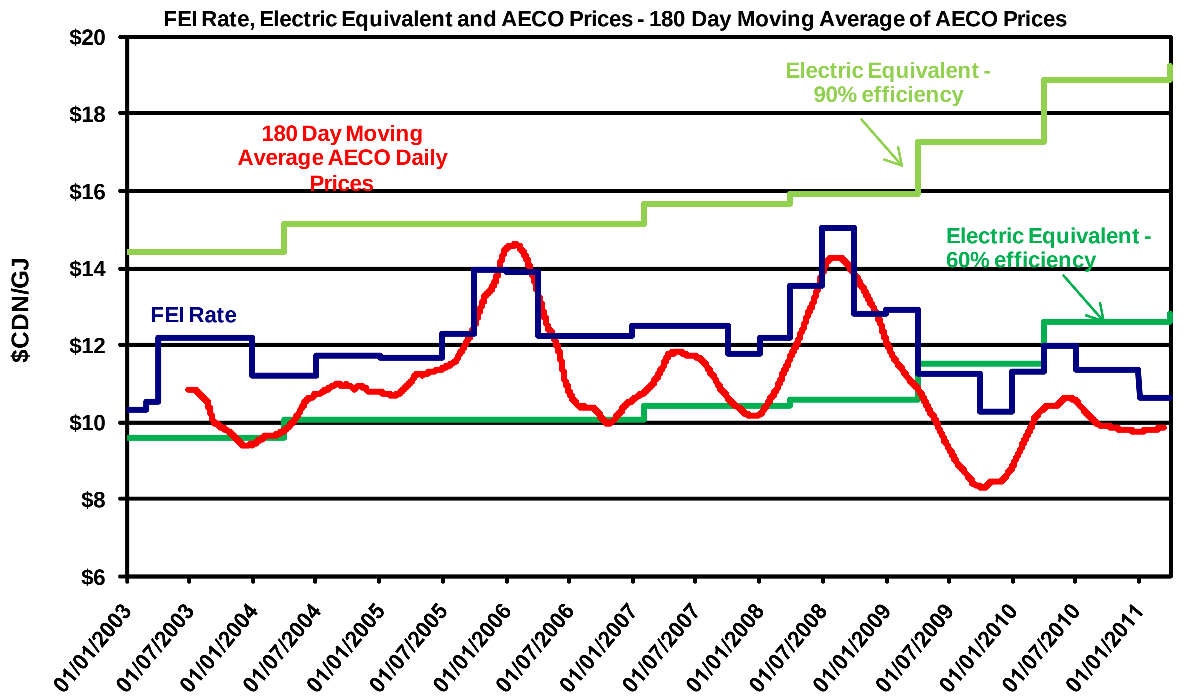
Please see Tables 1, 2 and 3 below for 120, 180, and 360 day moving averages.

Table 1: 120 Day Moving Average AECO Daily Price Compared to FEI Rate and Electric Equivalents



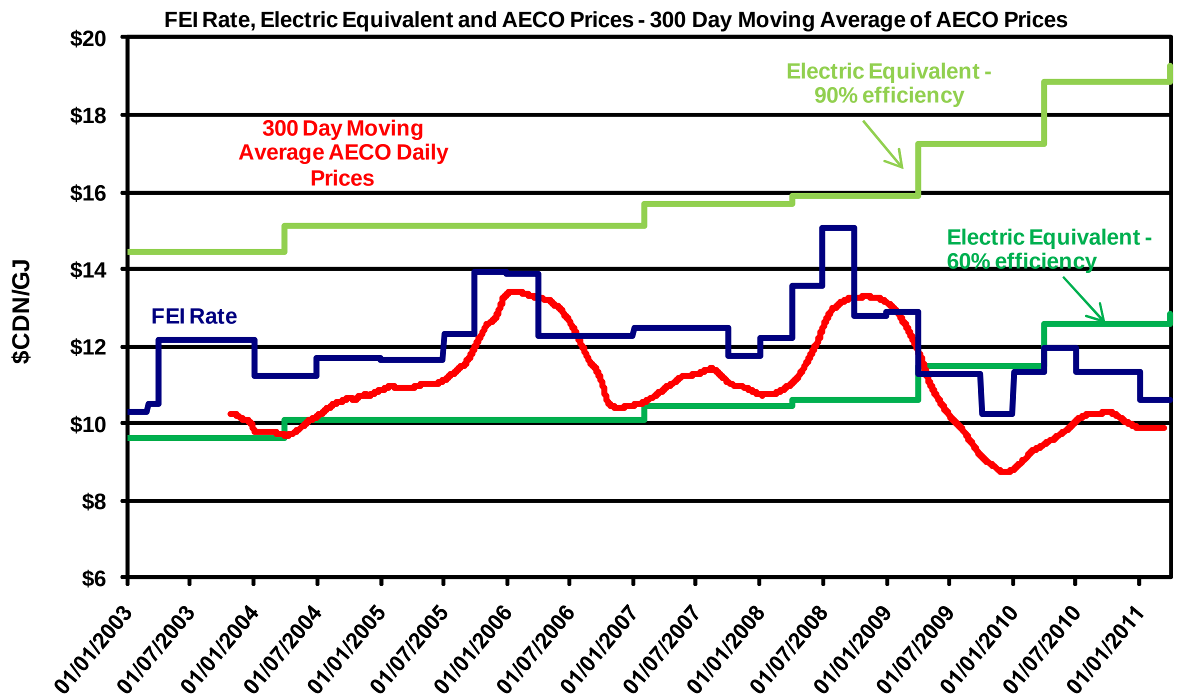
Notes: - *AECO prices adjusted up by FEI fixed, basic & delivery and midstream charges for comparison purposes*
- *Efficiency of gas furnace is 90% and gas hot water heater is 60% relative to 100% for electricity*

Table 2: 180 Day Moving Average AECO Daily Price Compared to FEI Rate and Electric Equivalents



Notes: *- AECO prices adjusted up by FEI fixed, basic & delivery and midstream charges for comparison purposes*
- Efficiency of gas furnace is 90% and gas hot water heater is 60% relative to 100% for electricity

Table 3: 300 Day Moving Average AECO Daily Price Compared to FEI Rate and Electric Equivalents



Notes: *- AECO prices adjusted up by FEI fixed, basic & delivery and midstream charges for comparison purposes*
- Efficiency of gas furnace is 90% and gas hot water heater is 60% relative to 100% for electricity

Attachment 3.1

Filed electronically ONLY to conserve paper

ERICA M. HAMILTON
COMMISSION SECRETARY
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BRITISH COLUMBIA UTILITIES COMMISSION

LETTER L-20-11

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VIA EMAIL
gas.regulatory.affairs@fortisbc.com

March 22, 2011

Ms. Diane Roy
Director, Regulatory Affairs Gas
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc.
Report on Gas Cost Deferral Accounts and Rate Setting Mechanisms

On February 5, 2001, the British Columbia Utilities Commission (Commission) issued Letter L-5-01 with Guidelines for a quarterly gas cost reporting process and which set out the conditions when BC Gas Utility Ltd. (now FortisBC Energy Inc. [FEI]) would generally be expected to apply for changes to commodity cost recovery rates. These Guidelines now apply for the FEI Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) and have generally been adopted by other gas and propane utilities in British Columbia.

In the letter that accompanied Order G-106-10 dealing with FEI's 2010 Second Quarter Gas Cost Report, the Commission directed Commission staff to work with FEI to investigate improvements to the MCRA forecasting capability and to revalidate the methodology associated with the quarterly review of CCRA costs and commodity rates. Following several discussions with Commission staff, on March 10, 2011 FEI filed the subject Report, which is attached to this letter. In the Report, FEI recommends three changes to improve the quarterly review and rate setting mechanisms. FEI characterizes the changes as "minor improvements".

The Commission invites parties with an interest in the matter to submit written comments on the recommended changes by Thursday, April 14, 2011 and to provide a copy of the comments to FEI. FEI may reply in writing to the comments by Friday, May 6, 2011. The Commission will then make a determination on the recommended changes to the Guidelines, with the intention that the updated Guidelines will apply for the review of the FEI 2011 Second Quarter Gas Cost Reports in early June 2011. The Commission anticipates that the updated Guidelines will also generally apply for other gas and propane utilities.

Yours truly,

N. Lapierre
for Erica M. Hamilton

JBW/yl
Enclosure
cc: Gas and Propane Utilities
Gas Marketers (NGM)
TGI-2010-11RR-RI

Diane Roy
Director, Regulatory Affairs Gas
FortisBC Energy Inc.

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Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

March 10, 2011

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc.
Report on the Commodity Cost Reconciliation Account ("CCRA") and Midstream Cost Reconciliation Account ("MCRA") Deferral Accounts and Rate Setting Mechanisms

FortisBC Energy Inc. ("FEI" or the "Company"), formerly Terasen Gas Inc., respectfully submits to the British Columbia Utilities Commission (the "Commission") the attached Report on the CCRA and MCRA Deferral Accounts and Rate Setting Mechanisms (the "Report"). The Commission issued Commission Order No. G-106-10 with respect to the Company's 2010 Second Quarter Gas Cost Report and, in its letter which accompanied Order No. G-106-10, directed Commission staff to work with the Company to investigate the possibility of improving the MCRA forecasting capability, and to revalidate the methodology associated with the quarterly review of the CCRA costs and commodity rates.

Commission staff and FEI held a number of discussions with respect to the CCRA and MCRA deferral accounts and rate setting mechanisms. As a result of those discussions, the following key areas were identified for FEI to conduct further analysis and review:

1. Natural Gas Commodity Price Forecasts;
2. CCRA Deferral Account and Rate Setting Mechanism; and
3. MCRA Deferral Account and Rate Setting Mechanism.

The attached Report provides the results of FEI's review, and the Company looks forward to working with Commission staff towards an efficient review of the attached report and the implementation of any changes to the Guidelines.

If you have any questions regarding the Report, please contact Brian Noel at (604) 592-7467.

Yours very truly,

FORTISBC ENERGY INC.

Original signed by: Shawn Hill

For: Diane Roy

Attachment

FortisBC Energy Inc.

Report on the
Commodity Cost Reconciliation Account (“CCRA”)
and Midstream Cost Reconciliation Account (“MCRA”)
Deferral Accounts and Rate Setting Mechanisms

March 10, 2011

Table of Contents

List of Appendices

1 INTRODUCTION

On June 15, 2010, the British Columbia Utilities Commission (the "Commission") issued Commission Order No. G-106-10 with respect to the Terasen Gas Inc. (now FortisBC Energy Inc.) 2010 Second Quarter Gas Cost Report. The Commission, in its letter dated June 15, 2010 (Log No. 32881) which accompanied Commission Order No. G-106-10, directed Commission staff to work with FortisBC Energy Inc. ("FEI" or the "Company"), to investigate the possibility of improving the Midstream Cost Reconciliation Account ("MCRA") forecasting capability, and to revalidate the methodology associated with the quarterly review of the Commodity Cost Reconciliation Account ("CCRA") costs and commodity rates. The Company, consistent with the Commission Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance (the "Guidelines") issued as Appendix I to Commission Letter No. L-5-01, files quarterly gas cost reports for Commission review.

Following the issuance of the Commission's June 15, 2010 letter, Commission staff and the Company held a number of discussions with respect to the CCRA and MCRA deferral accounts and rate setting mechanisms. As a result of those discussions, the following key areas were identified for the Company to conduct further analysis and review:

1. Commodity Price Forecasts – the forecast of natural gas commodity prices used in the determination of the gas cost forecasts for the quarterly review and resetting of rates.
2. CCRA Deferral Account and Rate Setting Mechanism – the effectiveness of the current 95% to 105% trigger ratio utilized to evaluate the appropriateness of the commodity cost recovery rate on a quarterly basis.
3. MCRA Deferral Account and Rate Setting Mechanism – the effectiveness of the current MCRA cost forecast and rate setting methodology, with a view to reducing rate volatility from year to year.

The Company believes the results of its review validate that the current CCRA and MCRA quarterly review and rate setting mechanisms, consistent with the Commission established Guidelines, have functioned appropriately up to now and continue to provide a strong base from which to build. FEI also believes that the suggested minor improvements noted in this Report on the CCRA and MCRA Deferral Accounts and Rate Setting Mechanisms (the "Report") will serve to further improve the quarterly review and rate setting mechanisms, thereby benefiting customers through reduction of the frequency of minor rate changes.

The balance of the Report is organized into the following sections:

<u>Section 2 – Background</u>

This section describes the background of the existing gas cost deferral account and rate setting mechanisms.

<u>Section 3 – Natural Gas Commodity Price Forecasts</u>

This section discusses the use of the NYMEX natural gas commodity futures as the underlying basis for the forecast gas costs and discusses a number of alternative approaches to determining the forward price of natural gas. The review puts forward the rationale for the continued use of the NYMEX natural gas commodity futures, and provides support that the use of a multi-day average of forward prices taken on consecutive market dates will reduce the variability inherent within the forward prices taken on a single date.

Section 4 – CCRA Deferral Account and Rate Setting Mechanism

This section discusses a number of alternative commodity rate change trigger mechanisms that were tested. The review supports that the existing ± 5% trigger ratio has functioned well and that a minor revision – the addition of a secondary parameter of a minimum $/GJ rate change threshold value – would enhance the effectiveness of the trigger mechanism in a low natural gas price environment, as is currently being experienced.

Section 5 – MCRA Deferral Account and Rate Setting Mechanism

This section discusses the alternative approach of amortizing 1/3 of the year end MCRA deferral balance in the following year's rates, compared to the existing methodology of amortizing the full balance each year. The review supports that the small change to the amortization methodology has the effect of dampening the year-to-year midstream rate change related to the annual midstream variances captured in the MCRA.

Section 6 – Summary

This section summarizes the findings and recommendations discussed within the previous sections of the report.

2 BACKGROUND

FEI acquires natural gas on behalf of its sales customers (Rate Schedules 1 through 7) and passes these costs through to sales customers without markup. Gas costs, including the costs of the commodity, and the third party pipeline and storage resources, are recovered from customers through gas cost recovery rates.

Generally speaking, gas cost recovery rates are established based on the forecast cost of gas for the prospective 12-month period. As gas cost recovery rates are based on forecast costs and actual costs invariably differ from forecast costs, gas cost deferral accounts have been established to accumulate the differences between the costs incurred to purchase the gas and the revenues collected through the gas cost recovery rates.

2.1 Gas Cost Reconciliation Account

On December 22, 1992, the Company (then called BC Gas Inc.) applied to the Commission to establish, effective January 1, 1993, a Gas Cost Reconciliation Account ("GCRA") for its Lower Mainland, Inland, Columbia, and Fort Nelson Divisions. Commission Order No. G-5-93 approved the use of a GCRA on an interim basis effective January 1, 1993.

The GCRA, as proposed in the Company's Phase B Rate Design Application dated April 15, 1993, was intended to capture the differences between forecast gas costs and the actual recovery of those costs from the Company's gas sales. The purpose of the GCRA was to ensure that the rates set for gas sales fully recover, but neither over nor under recover, the gas costs incurred by the Company. Commission Order No. G-101-93, and the Phase B Rate Design Application Decision issued concurrently with the Order, both dated October 25, 1993, approved the GCRA effective January 1, 1993.

2.2 Gas Cost Deferral Account and Rate Setting Guidelines

Prior to 1999, the gas cost recovery rates for the Company were established once per year, based on the forecast costs for the upcoming year and using a January 1st effective date. As a result of changing natural gas fundamentals, which led to the gas costs incurred during 1999 and 2000 being much higher than forecast, mid-year increases to gas cost recovery rates were requested by the Company to reduce the significant under-recovery of gas costs. And, even with the mid-year gas cost recovery rate increases, the Company's gas cost deferral account changed from a net surplus balance (gas cost recovery revenues exceeded gas costs incurred) to a net deficit balance (related costs exceeded gas cost recovery revenues) of approximately $180 million by the end of 2000.

The Commission asked its staff to prepare a report on the method of establishing gas cost recovery rates for the Company and amortizing the GCRA balance. The staff report was circulated to the Company and other parties on November 7, 2000; the Company and four other parties submitted comments.

On February 5, 2001, the Commission issued Commission Letter No. L-5-01 containing the Guidelines. The Guidelines were developed with specific reference to BC Gas Utility Ltd., later called Terasen Gas Inc. and now called FortisBC Energy Inc., however the Commission stated that it believed that the Guidelines were also appropriate for other gas utilities. A copy of Commission Letter No. L-5-01, including appendices, is attached herein as Appendix A.

The Guidelines set out the quarterly gas cost reporting process and the conditions under which the Commission would generally expect the Company to file applications for changes to commodity cost recovery rates and the method of amortizing the gas cost deferral balance.

The Commission noted that the Guidelines are intended as a general guide only. Nothing in the Guidelines precludes the Company from filing applications for rate changes at times other than those implied by the Guidelines or proposing alternate treatment of the gas cost deferral balance in unusual circumstances. Similarly, nothing in the Guidelines precludes the Commission from requesting rate applications at times other than those implied by the Guidelines.

Further, Commission Letter No. L-5-01 included Appendix II, titled Attributes of Deferral Account and Gas Cost Rate Setting Methodologies, which discussed the various attributes of deferral account and rate setting methodologies including rate stability, price transparency, implications for the expected size of the deferral account and efficiency of process.

2.3 Deferral Account Changes to Support Commodity Unbundling

On January 16, 2004, the Company filed the Commercial Commodity Unbundling and Customer Choice Phase 1 Cost Allocation Application (the "Application") wherein the Company, within Section 2 of the Application, requested approval for changes to the gas cost deferral account. Appendix B contains a copy of an excerpt from the Application containing Sections 1 and 2, and the applicable appendices. The Application requested approval for, among other items, the following:

- the assignment of existing GCRA components to either the Commodity function or the Midstream function, as outlined in Section 2 of the Application;

- the Commodity Cost Recovery Rates for the Sales Rate Schedules and a new deferral account, the CCRA, to be effective April 1, 2004, as outlined in Section 2 of the Application;
- the Midstream Cost Recovery Rates for the Sales Rate Schedules and a new deferral account, the MCRA, to be effective April 1, 2004, as outlined in Section 2 of the Application;
- 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 the Application;
- the mechanism to be 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 the Application; and
- the 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 the Application.

The Commodity Unbundling Program (both the initial Phase 1 Commercial program and the later Phase 2 Residential program), or Customer Choice, is available only to eligible natural gas customers in the Lower Mainland, Inland, and Columbia service areas (and thereby excluded the Fort Nelson and Revelstoke service areas).

Under the Essential Services Model it was necessary to separate the commodity costs, which would be recovered from customers electing to remain on the Company's Standard Rate Offering, from the midstream costs, which would continue to be recovered from all sales customers (Rate Schedules 1 through 7), and accordingly, a need for two separate deferral accounts in place of the GCRA (not applicable to the Fort Nelson service area GCRA). The CCRA and MCRA were established effective April 1, 2004 pursuant to Commission Order No. G-25-04, dated March 12, 2004, and the Reasons for Decision attached as Appendix A to the Order.

On April 13, 2006, the Company filed the Commodity Unbundling Project for Residential Customers CPCN Application, wherein the Company requested approval for consistent application of the Essential Services Model and the CCRA and MCRA mechanisms, currently in place for the Commercial Commodity Unbundling Program, for the Residential Commodity Unbundling Program. Commission approval was granted under Commission Order No. C-6-06, dated August 14, 2006.

Since then, the costs within the CCRA have become virtually fully variable in nature[1], resulting in a single commodity cost recovery rate being applicable to all FEI natural gas sales customers within the Lower Mainland, Inland, and Columbia service areas choosing to remain on the Standard Rate Offering. The Company files quarterly gas cost reports with the Commission; the commodity cost recovery rate is subject to quarterly review and resetting, if appropriate, by the Commission.

The MCRA contains the costs associated with the midstream resources (Appendix 1 of the Commercial Commodity Unbundling and Customer Choice Phase 1 Cost Allocation Application, attached to this Report under Appendix B, provides a detailed breakdown of the gas cost components assigned to the CCRA and the MCRA) which comprise a mixture of costs which are fixed in nature and those which are variable in nature. Consistent with the existing gas cost

[1] The last remaining 70/30 netback contracts, which included fixed and variable cost components, expired October 31, 2006.

rate design methodology, fixed costs are allocated to rate classes based on a load factor adjusted volumetric basis, while variable costs are allocated to rate classes based on a volumetric basis. Midstream cost recovery rates are reviewed quarterly as part of the Company's quarterly gas cost reports filed with the Commission however, under normal circumstances, the midstream rates are typically reset annually with a January 1st effective date.

2.4 Current Review of Deferral Accounts and Rate Setting Mechanisms

As discussed in the Introduction, a review of the deferral accounts and rate setting mechanisms has been undertaken pursuant to the Commission's directives in its June 15, 2010 letter, and following discussions between Commission staff and the Company on the CCRA and MCRA deferral accounts and rate setting mechanisms.

Consistent with the Commission established Guidelines, the Company's current quarterly gas cost reporting process supports the quarterly review of the CCRA balances and commodity rates and, as appropriate, the quarterly adjustment of commodity rates, as well as the quarterly review of the MCRA balances and midstream rates and, under normal circumstances, the annual adjustment of midstream rates with a January 1st effective date.

The objective of the quarterly gas cost review process is to establish commodity and midstream rates that appropriately recover the actual gas costs while continuing to balance the attributes of rate stability, price transparency, deferral account balances, and administrative efficiency, as discussed in Appendix II (titled "Attributes of Deferral Account and Gas Cost Rate Setting Methodologies") of Commission Letter No. L-5-01, and reiterated below:

- Rate Stability – refers to both the frequency of rate changes and the magnitude of the rate changes. Generally speaking, it is felt that customers would generally prefer fewer rather than more rate changes during the year, and would prefer the size of those rate changes be smaller rather than larger. However, at times when there is a persistent upward or downward trend in the price of natural gas, there may be a need to balance the conflicting nature of these goals.
- Price Transparency – refers to whether the commodity rates reflect market conditions and provide appropriate price signals to customers. Price transparency remains an important consideration, particularly since the availability of commodity unbundling for low volume customers under the Customer Choice Program.
- Deferral Account Balances – refers to the deferral account balances at the end of the current period as well as the balances forecast in future periods. Generally speaking, it is preferable to avoid large deferral account balances as any surplus or deficit amounts ultimately are refunded to or recovered from customers within future rates. Further, large deferral balances can mask the underlying commodity prices and price signals.
- Administrative Efficiency – refers to the efficiency of the review process related to the deferral account balances and the gas cost recovery rate setting mechanisms. In general, processes and rate adjustment mechanisms that are relatively simple to understand and require fewer resources to administer are preferred to those that are more complex and require greater administration.

The results of the FEI review, and the Company's recommendations, are summarized in the sections which follow. Appendix C, Appendix D, and Appendix E are attached to this Report.

Appendix C provides a chart showing the historical total effective rates, broken down by the various rate components, for a typical Lower Mainland Rate Schedule 1 residential customer consuming 95 GJ per year. Appendix D provides a chart showing the historical recorded monthly after-tax deferral balances for the GCRA / Combined CCRA + MCRA. Appendix E provides two charts which have been prepared to demonstrate the effects on the deferral account balances and the rates, based on the sample data taken from the January 2005 to January 2011 historical period, and based on a scenario where the commodity rate has been set on an annual basis with a January 1st effective date, similar to the midstream rates. The first chart in Appendix E shows the monthly after-tax deferral balances and the annual rates for the CCRA and MCRA on a combined basis, while the second chart shows the monthly after-tax deferral balances and the annual rate for just the CCRA. The results indicate the magnitude of the deferral account build, and the large swings in the recovery rates based on the sample data and under a scenario if both the commodity and the midstream recovery rates had been reset on an annual basis.

3 NATURAL GAS COMMODITY PRICE FORECASTS

This section discusses the use of the NYMEX natural gas commodity futures as the underlying basis for the forecast gas costs and looks at a number of alternative approaches to determining the forward price of natural gas to use in the calculation of the forecast gas costs for the Company's quarterly reports. Table 3.1 below, shows the forward strip dates used in each of the quarterly gas cost filings from the 2004 Deferred First Quarter Gas Cost Report, filed on April 8, 2004, to the 2010 Fourth Quarter Gas Cost Report, filed on December 2, 2010.

Table 3-1: Forward Strip Dates Used in Quarterly Gas Cost Filings

YEAR	QUARTER	FWD STRIP DATE	APPLICATION DATE	EFFECTIVE DATE	NOTES
2004	Q1	Mar 25, 2004	Apr 8, 2004	May 1, 2004	Q1 filing deferred
	Q1	Apr 15 2004	Apr 19, 2004	May 1, 2004	Revised and refiled
	Q1	Apr 19, 2004	Apr 21, 2004	May 1, 2004	Revised Q1 report
	Q2	May 31, 2004	June 7, 2004	July 1, 2004	Revised and refiled
	Q2	June 7, 2004	June 9, 2004	July 1, 2004	Revised Q2 report
	Q3	Aug 31, 2004	Sept 8, 2004	Oct 1, 2004	
	Q4	Nov 19, 2004	Dec 2, 2004	Jan 1, 2005	
2005	Q1	Feb 22, 2005	Mar 7, 2005	Apr 1, 2005	
	Q2	June 2, 2005	June 7, 2005	July 1, 2005	
	Q3	Aug 31, 2005	Sept 8, 2005	Oct 1, 2005	
	Q4	Nov 22, 2005	Dec 5, 2005	Jan 1, 2006	
2006	Q1	Feb 22, 2006	Mar 7, 2006	Apr 1, 2006	Revised and refiled
	Q1	Mar 7, 2006	Mar 13, 2006	Apr 1, 2006	Revised Q1 report
	Q2	May 26, 2006	June 6, 2006	July 1, 2006	
	Q3	Aug 21, 2006	Sept 1, 2006	Oct 1, 2006	
	Q4	Nov 21, 2006	Dec 4, 2006	Jan 1, 2007	
2007	Q1	Feb 28, 2007	March 5, 2007	Apr 1, 2007	
	Q2	June 1, 2007	June 7, 2007	July 1, 2007	
	Q3	Aug 28, 2007	Sept 7, 2007	Oct 1, 2007	
	Q4	Nov 26, 2007	Dec 3, 2007	Jan 1, 2008	
2008	Q1	Feb 27, 2008	Mar 7, 2008	Apr 1, 2008	
	Q2	May 28, 2008	June 6, 2008	July 1, 2008	
	Q3	Aug 27, 2008	Sept 4, 2008	Oct 1, 2008	Revised and refiled
	Q3	Sept 5, 2008	Sept 9, 2008	Oct 1, 2008	Revised Q3 report
	Q4	Nov 24, 2008	Dec 4, 2008	Jan 1, 2009	
2009	Q1	Feb 24, 2009	Mar 5, 2009	Apr 1, 2009	
	Q2	June 1, 2009	June 8, 2009	July 1, 2009	
	Q3	Aug 24, 2009	Sept 3, 2009	Oct 1, 2009	
	Q4	Nov 18, 2009	Dec 3, 2009	Jan 1, 2010	Revised and refiled
	Q4	Dec 2, 2009	Dec 7, 2009	Jan 1, 2010	Revised Q4 report
2010	Q1	Feb 23, 2010	Mar 4, 2010	Apr 1, 2010	
	Q2	May 25, 2010	June 3, 2010	July 1, 2010	
	Q3	Aug 18 - 24, 2010	Sept 3, 2010	Oct 1, 2010	Five-day average used
	Q4	Nov 17 - 23, 2010	Dec 2, 2010	Jan 1, 2011	Five-day average used

The Company continues to support that the NYMEX natural gas commodity futures market for the following 12 month period provides a forecast of the natural gas commodity prices which theoretically incorporates all of the information currently available to the market, and that changes in the futures prices over time reflects how the market interprets the most recent information. The natural gas commodities market is a dynamic market, and variations in the commodity futures prices are reflective of the natural gas price trends. However, FEI also believes that the changes in futures prices from any one day to the next in such a dynamic market may not always appropriately reflect pricing trends (i.e. sudden events may cause outliers or price changes that are not reflective of underlying pricing trends) and therefore reliance on a single forward strip date has the potential to distort the gas cost forecast.

Although using the forward market to forecast prices over the next 12 months is appropriate, an approach which would be expected to reduce the variability caused by day-to-day fluctuations in the commodity futures prices would be to use natural gas commodity futures prices based on an average of a number of consecutive market dates. Thus, FEI has reviewed the degree of variability historically shown in using a single forward strip date compared to using a 2-day, 3-day, 4-day, 5-day, 6-day, and 10-day average of consecutive forward strip dates.

To provide a comprehensive and balanced analysis, the natural gas forward prices based on all the NYMEX forward strip dates from January 2004 to September 2010 were compiled and reviewed. In general, for each month reviewed, the last business day of the month was used as the benchmark for analysis except in months where a quarterly report was filed with the Commission, the actual forward strip date used in the filing was used for comparison purposes.

The amount of variability in each of the multi-day averages was calculated and charted. A summary of the results are included in Section 3.1 in a graphical format to provide a visual summary of the findings.

3.1 Forward Price Variability Indicator

For the period January 2004 to September 2010, the variability in the prospective 12-month commodity futures monthly prices for each calendar month during the January 2004 to September 2010 period was calculated using a mathematical formula called the standard deviation. The standard deviation is often used in statistical analysis to determine the spread of values in a range of data.

The standard deviation is valuable because it illustrates the degree of range, or variability, from the mean or average in a specific set of data. A data set with a wide range of data values, or high degree of variability, will have a high standard deviation value. The higher the standard deviation, the further away data points fall in relation to the average value in the data set. In contrast, a group of data that contains values that are closely clustered around the average value will have a low standard deviation, and therefore relatively little variability.

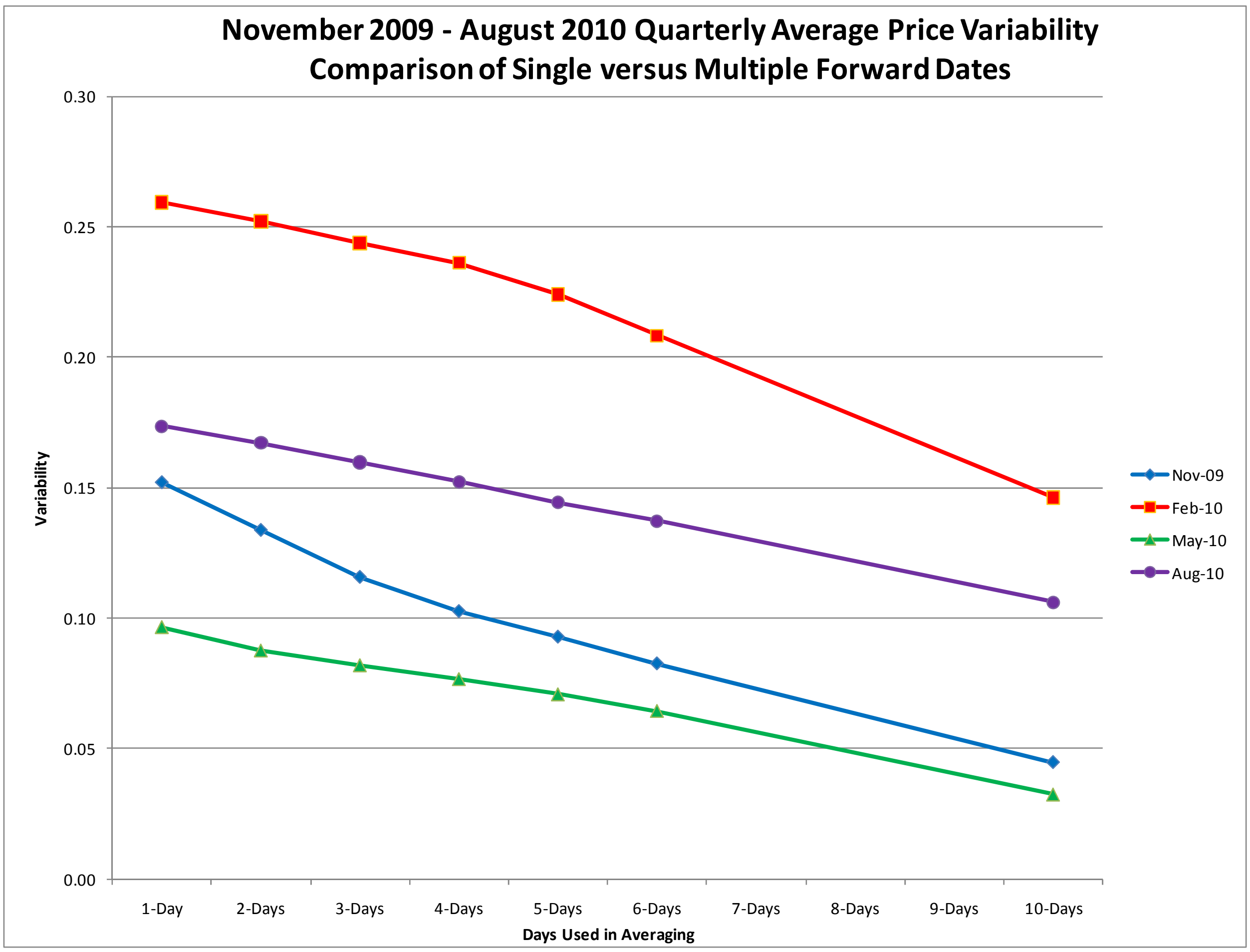
For each calendar month during the January 2004 to September 2010 period (e.g. for the month of August 2010 – gas cost forecasts within the Company's 2010 Third Quarter Gas Cost Report were based on August NYMEX forward strip dates), a standard deviation was first calculated on a set of pricing data, for each subsequent month within the prospective 12-month period (e.g. for October 2010, then for November 2010, etc. – the prospective 12-month period for the 2010 Third Quarter Gas Cost Report was October 2010 to September 2011), based on the single date forward strip price at each NYMEX business day in the calendar month (e.g. August 2010). The standard deviation results for the prospective 12-month period were then averaged to produce a single value for comparative purposes.

This value was then compared to the average 12-month standard deviation calculated on the set of pricing data based on the forward strip date plus the immediately preceding date being averaged. This provided the standard deviation that would result from using a two-day average price. This methodology was then repeated for a 3-day, 4-day, 5-day, 6-day, and 10-day average price.

This comparison demonstrates the amount of variability that occurs between a single forward strip date and the amount of variability that would occur if a multi-day average were used. It is predicted that the greater the number of days used for averaging, the lower the standard deviation, or variability.

The following chart shows the variability of prices, as measured in standard deviation, for four quarterly gas cost reporting periods, beginning with the 2009 fourth quarter which used the forward prices from November 2009. The chart pattern is consistent throughout each quarter, and shows that variability decreases as the number of days used in averaging rates increases.

Chart 3-1: Price Variability of Single versus Multiple Forward Strip Dates



The variability is highest for the 1-day value, and lowest for the 10-day average. This is consistent with what we would expect to see. As the data is averaged over a larger period of time, the variability is essentially stripped out.

Chart 3-2 below, shows the same data from Chart 3-1, with the addition of the data from the October 2005 forward prices. The October 2005 forward prices are representative of a period when there was a fair degree of volatility within the natural gas markets (and included the effects of the Hurricane Katrina). The chart pattern is consistent with what would be expected, and with that shown in Chart 3-1. And although the magnitude of the variation is greater, the data shows that the variation is reduced considerably when four or more days are averaged; the 5-day average appears to provide an acceptable level of variation while ensuring the price data remains current.

Chart 3-2: October 2005 Data Added to the Price Variability Comparison Shown in Chart 3-1

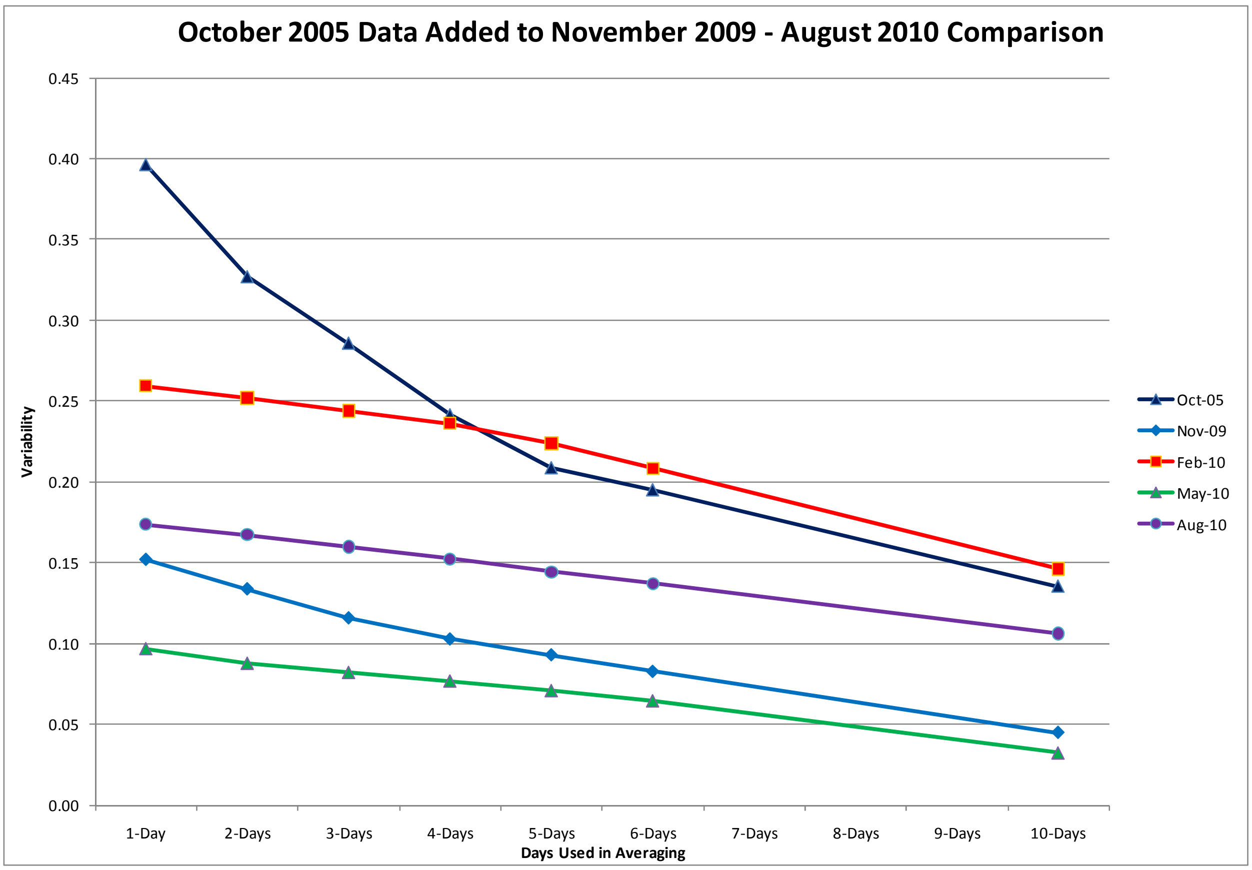
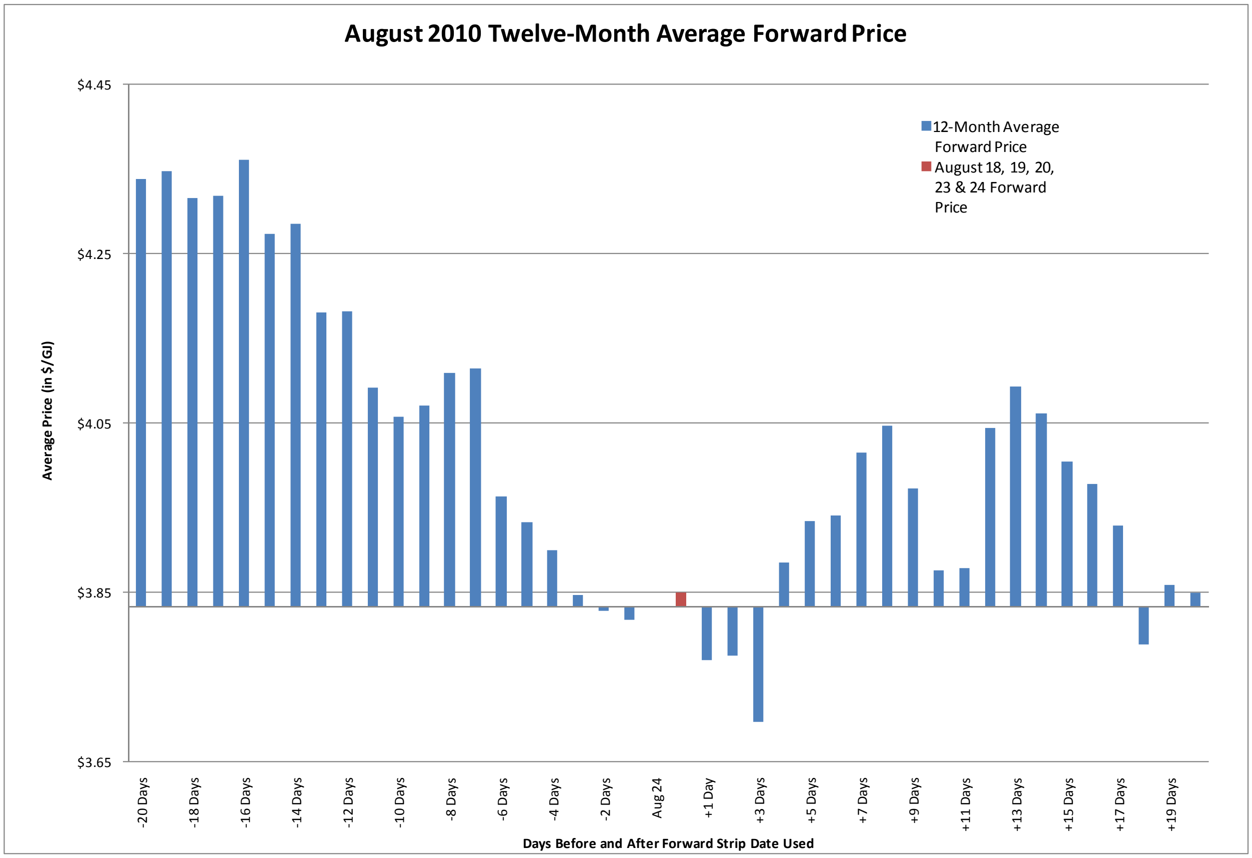


Chart 3-3 below, shows the variations in the 12-month average price of natural gas (in $/GJ) for the forward strip dates before and after the August 24 forward strip date used in establishing the 5-day average for the 2010 third quarter gas cost report.

Chart 3-3: Absolute $/GJ Variations in the August 2010 Twelve-Month Average Forward Prices



The results of the analysis, as shown in the Charts 3-1 to 3-3, suggest that the larger the date range used for determining an average commodity price, the smaller the chance of relying on a single, possibly misrepresentative price point. This may lead to the assumption that using a large data set for averaging is preferable.

While variability may be reduced with a large data set, in an environment where market conditions change daily, it is important to utilize the latest data available. With a large data sample such as this, there is the possibility of including data that is no longer representative of the latest market prices, which would lead to an inaccurate forecast. FEI believes that a multi-day average is preferable to a single forward strip date and supports the use of a 5-day average; FEI believes that a longer period such as a 6-day or 10-day period is not desirable as longer periods will contain older price data which is more likely to be based on stale information.

3.2 Natural Gas Commodity Price Forecast Recommendations

FEI continues to support that the NYMEX natural gas commodity futures market provides an appropriate market view of the natural gas commodity prices for use in the determination of the gas cost forecasts used in the Company's quarterly gas cost filings.

In addition, the Company believes that a multi-day average is preferable to a single forward strip date and recommends that a 5-day average be adopted. The use of a 5-day average will provide an appropriate mechanism that reduces price variability while providing an average price that reflects current market conditions.

4 CCRA DEFERRAL ACCOUNT AND RATE SETTING MECHANISM

As discussed in Section 2, the Commission issued Commission Letter No. L-5-01, dated February 5, 2001, which contained the Guidelines, and established a rate adjustment trigger mechanism. The rate adjustment trigger mechanism calculates the ratio of the forecast 12 month gas cost recovery revenues, at current rates, compared to the forecast 12 month cost of gas, including the projected balance in the deferral account to the end of the current period. A ratio falling within a 95% to 105% deadband indicates that current rates are appropriately recovering gas costs and should remain unchanged, while a ratio falling outside the deadband indicates that a rate change may be required.

Generally speaking, the 95% to 105% rate adjustment trigger mechanism has been utilized since the Guidelines were issued and, with the splitting of the GCRA into the CCRA and the MCRA in 2004, the rate adjustment ratio has been applicable to the quarterly review of CCRA-related commodity cost recovery rates (also referred to as the CCRA rate).

To assess the appropriateness of the existing commodity rate adjustment trigger mechanism, the Company has created four scenarios, testing a number of alternative rate adjustment trigger mechanisms methods using historical data and comparing the results against the historical results.

In the first scenario (Scenario A) the deadband range remains at 95% to 105%, but has been expanded to include an additional threshold which requires an absolute dollar value change of greater than $0.50/GJ in order to trigger a rate change. The second and third scenarios (Scenarios B and C) test widening the deadband range to the 92.5% to 107.5% and 90% to 110% ranges, respectively. And lastly, a fourth scenario (Scenario D) examines the impact on rates if the forecast 12-month ending deferral balance were allowed to reach a surplus or deficit balance of $50 million, on a grossed-up after-tax basis, before triggering a rate change, thereby utilizing a flat dollar value in place of a percentage based mechanism.

The following assumptions have been applied in preparing each of the alternative test scenarios:

1. The commodity cost recovery rate applicable to Lower Mainland Rate Schedule 1 (LM RS 1) residential customers was used to evaluate and compare all scenarios.[2]
2. The analysis was restricted to changes in the CCRA and assumed all other factors remained unaffected by the changes in the commodity rates. Of particular note, the historical CCRA gas cost forecasts are based on the partially hedged portfolio in place during those periods. A portion, as determined from the forecast supply volumes, of the CCRA commodity was hedged through the use of financial derivatives and insulated the CCRA commodity costs related to those volumes from the full impact of changes in the market price of natural gas. The remaining portion of the CCRA commodity was unhedged, or floated in relation to the price of natural gas, and was exposed to the full impact of changes in the market price of natural gas. On January 27, 2011, the

[2] Prior to April 1, 2008, there were slight differences in commodity cost recovery rates between Sales rate classes due to a very small portion of the costs in the CCRA being treated as fixed for rate setting purposes.

Company filed on a confidential basis the results of the Commission directed review of the Price Risk Management Plan objectives and the recommendations for an enhanced hedging strategy. On January 27, 2011, the Company also filed on a confidential basis its 2011-2014 Price Risk Management Plan ("2011 PRMP") seeking approval of the objectives and key elements of the 2011 PRMP. Pursuant to Commission Order No. G-23-11, dated February 22, 2011, the 2011 PRMP objectives will be examined by way of a written public hearing process. The Company emphasizes that any material changes to the hedging within the CCRA portfolio could materially affect the variability between forecast and actual CCRA gas costs and subsequent deferral balances.

3. The analysis conducted utilized the historical quarterly gas cost data covering the six-year period from the 2004 Fourth Quarter Gas Cost Report to the 2010 Fourth Quarter Gas Cost Report.

Beginning with the same data used in preparing the 2004 Fourth Quarter Gas Cost Report, filed on December 2, 2004, the rate determination process has been tested under each of the four scenarios, and this process was continued for each consecutive quarter. When the tested criteria resulted in "setting" a different commodity rate than the original report had produced, the revenue and deferral balance forecasts were recalculated, and the "new" commodity rate was used in following quarters. The subsections which follow provide the results of the analysis under the various scenarios, with each subsection summarizing the results produced under that particular tested scenario and comparing them to the historical results.

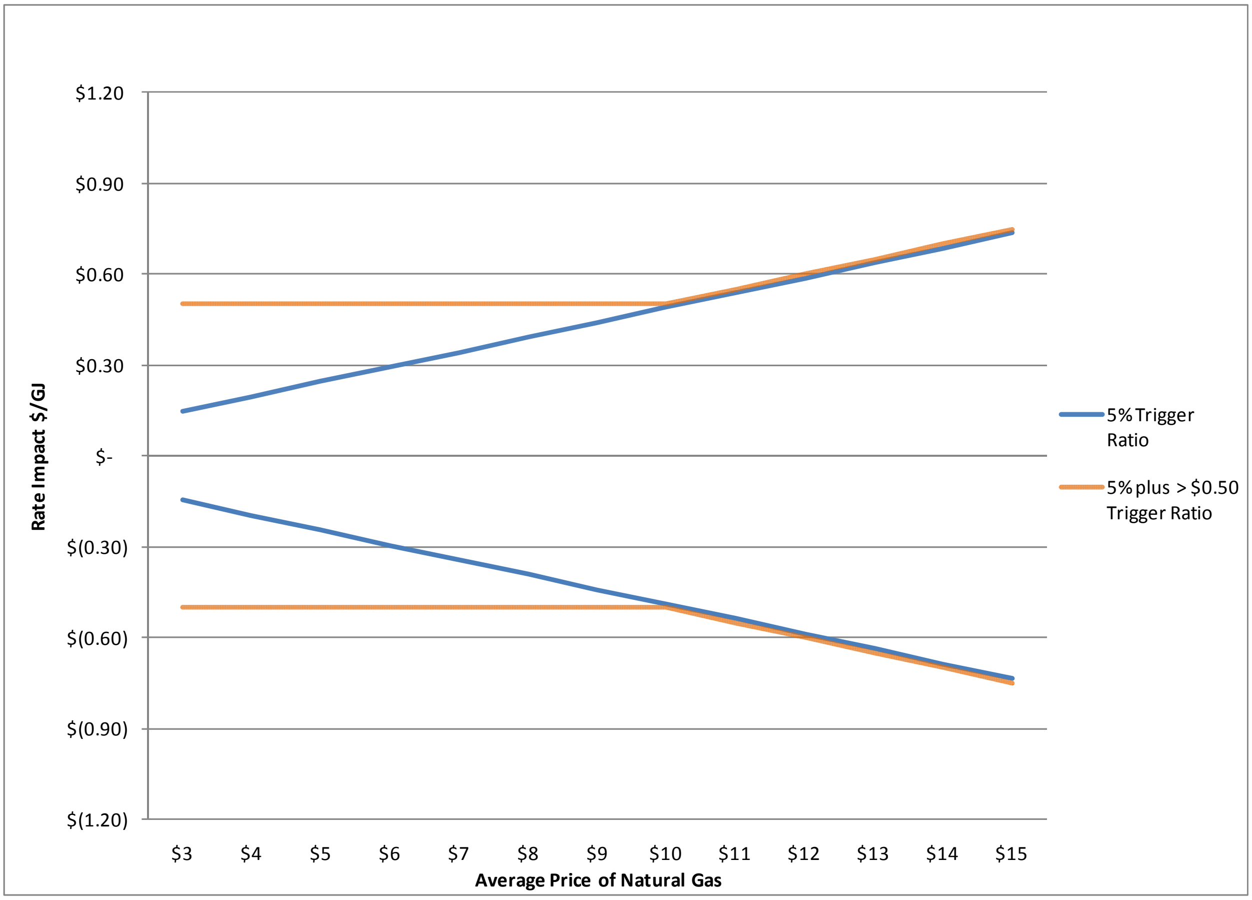
4.1 Scenario A: 95% to 105% Deadband Plus Rate Change > $0.50/GJ

During periods where natural gas prices are relatively low, a rate change trigger mechanism based solely on a percentage basis may trigger a rate change that results in a very small $/GJ change, as well as a very small change on a total billed basis. For example, with natural gas prices below $5.00/GJ, the current trigger ratio of ± 5% could result in a rate change of less than $0.25/GJ which would equate to a change of less than $24 in the annual bill for a typical Lower Mainland residential customer with an average annual consumption of 95 GJ.

Scenario A retains the existing trigger ratio of ± 5% but adds an additional threshold such that a minimum change of $0.50/GJ would also need to be met in order to trigger a rate change. The addition of such a minimum value would be expected to provide an additional component of stability to commodity rates by maintaining a minimum ± $0.50/GJ deadband when the ± 5% deadband narrows as a result of lower natural gas prices.

Chart 4-1 displays the rate impact effects of the Scenario A alternative trigger ratio mechanism of ± 5% plus the minimum change threshold of $0.50/GJ compared to the effects of the existing trigger ratio of ± 5%, at various natural gas prices. The chart shows how the ± 5% deadband narrows in $/GJ terms as the average price of natural gas becomes lower which could result in triggering a rate change that is small in a $/GJ amount and which could be considered unnecessary.

Chart 4-1: Rate Impact of ±5% Plus >$0.50/GJ Trigger Ratio Compared to Existing ±5% Trigger Ratio



Whether or not the addition of the ± $0.50/GJ threshold would ultimately result in an overall lower number or frequency of rate changes would depend upon what happens to the market price of natural gas. However, the addition of the ± $0.50/GJ threshold would effectively avoid triggering what could be considered relatively immaterial rate changes, when the ± 5% deadband narrows as a result of lower natural gas prices.

Table 4-1 summarizes the results from Scenario A. For comparative purposes, the actual results and the tested results are presented side by side. The “Filed” portion of the table summarizes the actual historical results from the quarterly filings while the “Tested” portion of the table shows the results that would have occurred had the Scenario A commodity rate adjustment trigger mechanism been used. Further, the “Net Impact” columns are provided to highlight the differences in deferral balances and rates between the two rate setting mechanisms.

Table 4-1: 95% to 105% Deadband Plus Rate Change > $0.50/GJ

PERIOD	Filed					Tested					Net Impact	
	DEFERRAL BALANCE ($ million)	TRIGGER RATIO (%)	EXISTING LM RS 1 ($/GJ)	PROPOSED LM RS 1 ($/GJ)	LM RS 1 CHANGE ($/GJ)	DEFERRAL BALANCE ($ million)	TRIGGER RATIO (%)	EXISTING LM RS 1 ($/GJ)	PROPOSED LM RS 1 ($/GJ)	LM RS 1 CHANGE ($/GJ)	DEFERRAL BALANCE ($ million)	RATE CHANGE ($/GJ)
2004 Q4	$ 2	99.9	$ 7.005	$ 7.005	$ -	$ 2	99.9	$ 7.005	$ 7.005	$ -	$ -	$ -
2005 Q1	(6)	100.6	7.005	7.005	-	(6)	100.6	7.005	7.005	-	-	-
2005 Q2	71	91.5	7.005	7.658	0.653	71	91.5	7.005	7.658	0.653	-	-
2005 Q3	180	82.4	7.658	9.292	1.634	180	82.4	7.658	9.292	1.634	-	-
2005 Q4	52	95.0	9.292	9.774	0.482	52	95.0	9.292	9.292	-	-	(0.482)
2006 Q1	(227)	127.6	9.774	7.662	(2.112)	(163)	119.5	9.292	7.771	(1.521)	64	0.109
2006 Q2	3	99.6	7.662	7.662	-	(11)	101.4	7.771	7.771	-	(14)	0.109
2006 Q3	1	99.8	7.662	7.662	-	(13)	101.6	7.771	7.771	-	(15)	0.109
2006 Q4	12	98.6	7.662	7.662	-	(3)	100.4	7.771	7.771	-	(15)	0.109
2007 Q1	36	95.7	7.662	7.662	-	19	97.8	7.771	7.771	-	(17)	0.109
2007 Q2	1	99.8	7.662	7.662	-	(12)	101.6	7.771	7.771	-	(13)	0.109
2007 Q3	(95)	115.0	7.662	6.926	(0.736)	(109)	117.2	7.771	6.649	(1.122)	(14)	(0.277)
2007 Q4	7	99.0	6.926	6.926	-	39	94.1	6.649	6.649	-	32	(0.277)
2008 Q1	129	83.5	6.926	8.287	1.361	161	79.5	6.649	8.355	1.706	32	0.068
2008 Q2	142	84.7	8.287	9.780	1.493	134	85.6	8.355	9.761	1.406	(8)	(0.019)
2008 Q3	(214)	129.8	9.780	7.536	(2.244)	(212)	129.4	9.761	7.532	(2.229)	2	(0.004)
2008 Q4	13	98.1	7.536	7.536	-	13	98.2	7.532	7.532	-	0	(0.004)
2009 Q1	(136)	126.4	7.536	5.962	(1.574)	(135)	126.3	7.532	5.962	(1.570)	1	-
2009 Q2	(34)	107.5	5.962	5.962	-	(34)	107.5	5.962	5.962	-	-	-
2009 Q3	(91)	120.4	5.962	4.953	(1.009)	(91)	120.4	5.962	4.953	(1.009)	-	-
2009 Q4	25	95.2	4.953	4.953	-	25	95.2	4.953	4.953	-	-	-
2010 Q1	63	88.4	4.953	5.609	0.656	63	88.4	4.953	5.609	0.656	-	-
2010 Q2	(60)	112.7	5.609	4.976	(0.633)	(60)	112.7	5.609	4.976	(0.633)	-	-
2010 Q3	(32)	107.3	4.976	4.976	-	(32)	107.3	4.976	4.976	-	-	-
2010 Q4	(39)	109.1	4.976	4.568	(0.408)	(39)	109.1	4.976	4.976	-	-	0.408

*Deferral Balances shown in the table are the 12-Month Forecast Ending Deferral Balances grossed-up to reflect amounts flowed through for rate setting purposes.
*Grossed-up balances may contain slight differences due to rounding.

The first quarter where the Scenario A alternative rate adjustment trigger mechanism would produce different results is the 2005 fourth quarter review. Under the tested Scenario A parameters, the rate increase of $0.482 would not be implemented because it falls below the minimum $0.50/GJ change criteria. Scenario A would still trigger a rate decrease in the subsequent, 2006 first quarter review, however the amount of the decrease would be smaller (e.g. a tested decrease of $1.521/GJ compared to the actual decrease of $2.112/GJ).

In both scenarios, the rate stabilizes for several quarters until the third quarter of 2007, when the tested scenario results in a wider swing in the CCRA rate than what actually occurred. (e.g. a tested decrease of $1.122/GJ compared to the actual decrease of $0.736/GJ).

Throughout the entire six-year period reviewed there are several relatively small differences between the actual and tested results. During the 2008 period the differences become even smaller, with the commodity rate becoming the same under both mechanisms at the 2009 first quarter review and remaining that way for most of the remainder of the period reviewed. Though it should be noted that the trigger ratio calculated within the 2010 third quarter review, as filed, was outside the 95% to 105% deadband, but equated to a relatively small rate change of $0.339/GJ; the Company's proposal to leave rates unchanged at October 1, 2010 was accepted by the Commission. The trigger ratio calculated within the 2010 fourth quarter review, as filed, was outside the 95% to 105% deadband and equated to a relatively small rate change of $0.408/GJ, the Company's proposal to decrease rates effective January 1, 2011 was accepted by the Commission however under Scenario A this rate change would likely have been avoided.

Although the results of the Scenario A analysis are not dramatically different than the actual historical results, the addition of the ± $0.50/GJ threshold would effectively avoid triggering what could be considered a relatively immaterial rate change when the ± 5% deadband has narrowed as a result of lower natural gas prices. The review suggests that a minor revision to the existing ± 5% trigger ratio – the addition of a secondary parameter of a minimum $/GJ rate change threshold value – would enhance the effectiveness of the trigger mechanism in a low natural gas price environment. The Scenario A alternative mechanism could be expected to provide a greater degree of stability to the rate change trigger mechanism during low commodity price environments, such as currently being experienced.

4.2 Scenario B: 92.5% to 107.5% Deadband

Scenario B tests the alternative of changing the trigger ratio from the existing ± 5% to a trigger ratio of ± 7.5%. The widening of the deadband range to 92.5% to 107.5% would be expected to provide an additional component of stability to commodity rates, as compared to the existing 95% to 105% deadband range, under all commodity price conditions.

Chart 4-2 displays the rate impact effects of the Scenario B alternative trigger ratio mechanism of ± 7.5% compared to the effects of the existing trigger ratio of ± 5%, at various natural gas prices. The chart shows how the ± 7.5% deadband is wider at the various price points for natural gas.

Chart 4-2: Rate Impact of ±7.5% Trigger Ratio Compared to Existing ±5% Trigger Ratio

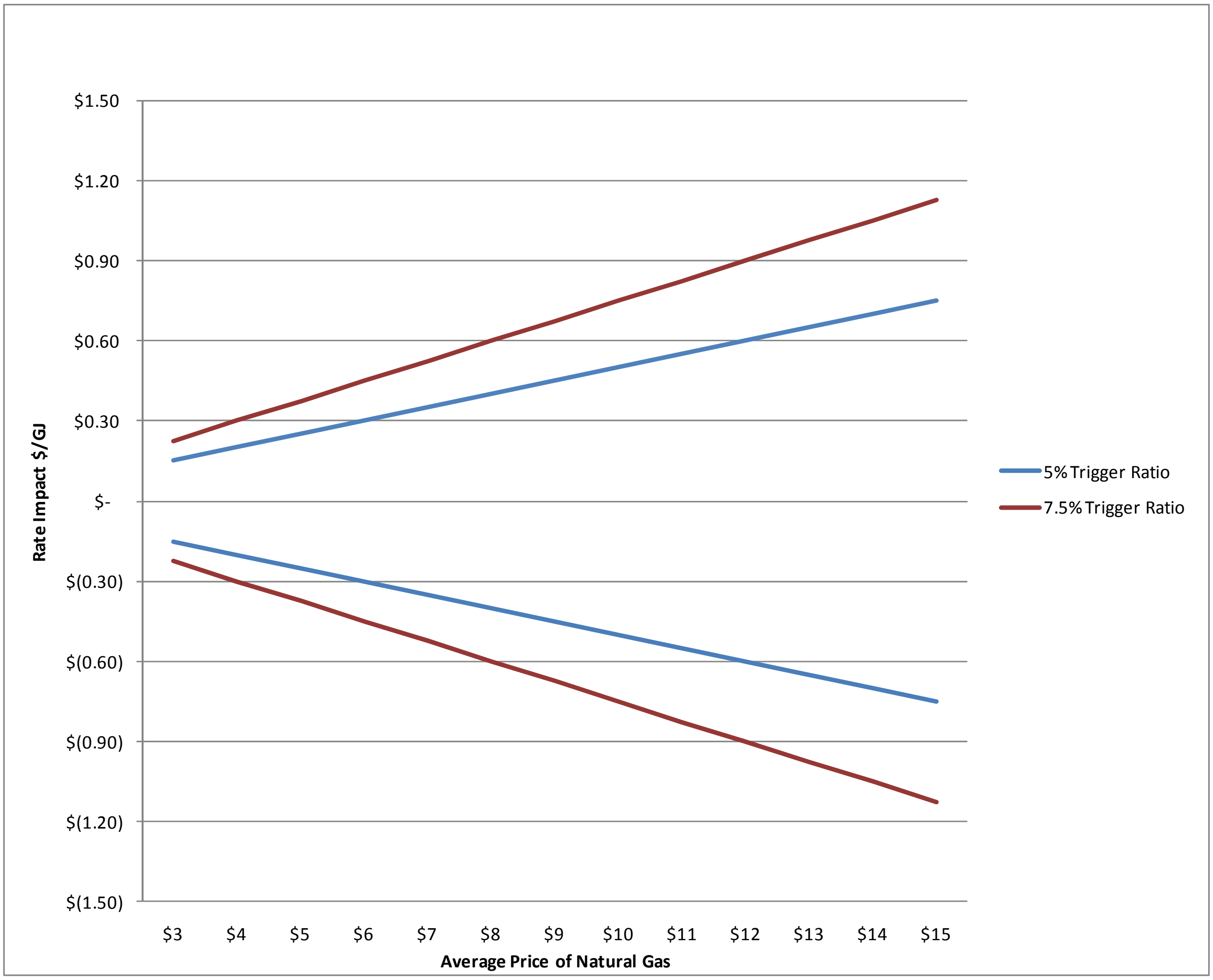


Table 4-2 summarizes the results from Scenario B. For comparative purposes, the actual results and the tested results are presented side by side. The "Filed" portion of the table summarizes the actual historical results from the quarterly filings while the "Tested" portion of the table shows the results that would have occurred had the Scenario B commodity rate adjustment trigger mechanism been used. Further, the "Net Impact" columns are provided to highlight the differences in deferral balances and rates between the two rate setting mechanisms.

Table 4-2: 92.5% to 107.5% Deadband

PERIOD		Filed					Tested					Net Impact	
		DEFERRAL BALANCE ($ million)	TRIGGER RATIO (%)	EXISTING LM RS 1 ($/GJ)	PROPOSED LM RS 1 ($/GJ)	LM RS 1 CHANGE ($/GJ)	DEFERRAL BALANCE ($ million)	TRIGGER RATIO (%)	EXISTING LM RS 1 ($/GJ)	PROPOSED LM RS 1 ($/GJ)	LM RS 1 CHANGE ($/GJ)	FORECAST BALANCE ($ million)	RATE CHANGE ($/GJ)
2004	Q4	$ 2	99.9	$ 7.005	$ 7.005	$ -	$ 2	99.9	$ 7.005	$ 7.005	$ -	$ -	$ -
2005	Q1	(6)	100.6	7.005	7.005	-	(6)	100.6	7.005	7.005	-	-	-
2005	Q2	71	91.5	7.005	7.658	0.653	71	91.5	7.005	7.658	0.653	-	-
2005	Q3	180	82.4	7.658	9.292	1.634	180	82.4	7.658	9.292	1.634	-	-
2005	Q4	52	95.0	9.292	9.774	0.482	52	95.0	9.292	9.292	-	-	(0.482)
2006	Q1	(227)	127.6	9.774	7.662	(2.112)	(163)	119.5	9.292	7.771	(1.521)	64	0.109
2006	Q2	3	99.6	7.662	7.662	-	(11)	101.4	7.771	7.771	-	(14)	0.109
2006	Q3	1	99.8	7.662	7.662	-	(13)	101.6	7.771	7.771	-	(15)	0.109
2006	Q4	12	98.6	7.662	7.662	-	(3)	100.4	7.771	7.771	-	(15)	0.109
2007	Q1	36	95.7	7.662	7.662	-	19	97.8	7.771	7.771	-	(17)	0.109
2007	Q2	1	99.8	7.662	7.662	-	(12)	101.6	7.771	7.771	-	(13)	0.109
2007	Q3	(95)	115.0	7.662	6.926	(0.736)	(109)	117.2	7.771	6.649	(1.122)	(14)	(0.277)
2007	Q4	7	99.0	6.926	6.926	-	39	94.1	6.649	6.649	-	32	(0.277)
2008	Q1	129	83.5	6.926	8.287	1.361	161	79.5	6.649	8.355	1.706	32	0.068
2008	Q2	142	84.7	8.287	9.780	1.493	134	85.6	8.355	9.761	1.406	(8)	(0.019)
2008	Q3	(214)	129.8	9.780	7.536	(2.244)	(212)	129.4	9.761	7.532	(2.229)	2	(0.004)
2008	Q4	13	98.1	7.536	7.536	-	13	98.2	7.532	7.532	-	0	(0.004)
2009	Q1	(136)	126.4	7.536	5.962	(1.574)	(135)	126.3	7.532	5.962	(1.570)	1	-
2009	Q2	(34)	107.5	5.962	5.962	-	(34)	107.5	5.962	5.962	-	-	-
2009	Q3	(91)	120.4	5.962	4.953	(1.009)	(91)	120.4	5.962	4.953	(1.009)	-	-
2009	Q4	25	95.2	4.953	4.953	-	25	95.2	4.953	4.953	-	-	-
2010	Q1	63	88.4	4.953	5.609	0.656	63	88.4	4.953	5.609	0.656	-	-
2010	Q2	(60)	112.7	5.609	4.976	(0.633)	(60)	112.7	5.609	4.976	(0.633)	-	-
2010	Q3	(32)	107.3	4.976	4.976	-	(32)	107.3	4.976	4.976	-	-	-
2010	Q4	(41)	109.1	4.976	4.568	(0.408)	(41)	109.1	4.976	4.568	(0.408)	-	-

*Deferral Balances shown in the table are the 12-Month Forecast Ending Deferral Balances grossed-up to reflect amounts flowed through for rate setting purposes.
*Grossed-up balances may contain slight differences due to rounding.

At a glance, Table 4-2 shows that the results of the Scenario B analysis are basically the same as those produced in Scenario A.

The first quarter where the Scenario B alternative rate adjustment trigger mechanism would produce different results from those of the filed quarterly reviews is the 2005 fourth quarter review. Under the tested Scenario B parameters, the rate increase of $0.482 would not be triggered because the rate change trigger ratio falls within the ± 7.5% range.

The numbers then flow through the rest of the quarters under the Scenario B alternative just as they did in Scenario A, with rate change dates and amounts remaining the same until the 2010 fourth quarter when the results under Scenario A support no rate change while the results under Scenario B support a rate change – the increased ± 7.5% range under Scenario B for the 2010 fourth quarter still triggers a rate change in the current low price environment even though the amount of that rate change is only $0.408/GJ. The fact that the results are basically the same under both Scenario A and Scenario B is not that surprising when one looks at the underlying historical data used in the sample. Generally speaking, when the sample data trigger ratio fell outside the 95% to 105% deadband, the over or under recovery was material enough that it also fell outside the 92.5% to 107.5% deadband; the couple of instances that the trigger ratio was outside the 95% to 105% deadband but not outside the 92.5% and 107.5% deadband, the indicated rate change fell within the Scenario A minimum $0.50/GJ deadband, at least until the commodity rate fell to its current low rate as demonstrated in the 2010 fourth quarter results.

4.3 Scenario C: 90.0% to 110.0% Deadband

Scenario C tests the alternative of changing the trigger ratio from the existing ± 5% to a trigger ratio of ± 10%. The widening of the deadband range to 90% to 110% would be expected to provide an additional component of stability to commodity rates, as compared to the existing 95% to 105% deadband range, under all commodity price conditions.

Chart 4-3 displays the rate impact effects of the Scenario C alternative trigger ratio mechanism of ± 10% compared to the effects of the existing trigger ratio of ± 5%, at various natural gas prices. The chart shows how the ± 10% deadband is much wider at the various price points for natural gas.

Chart 4-3: Rate Impact of ±10% Trigger Ratio Compared to Existing ±5% Trigger Ratio

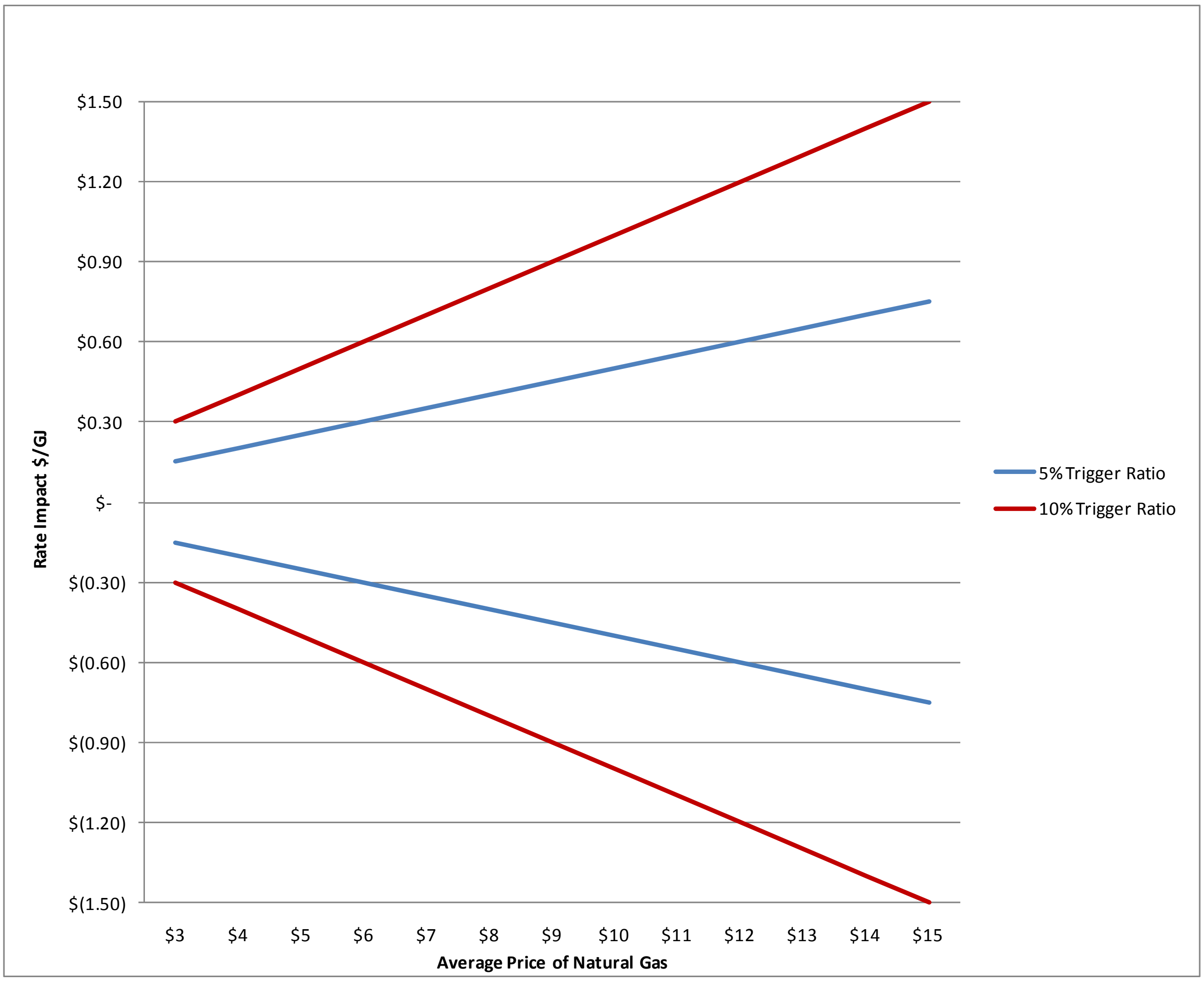


Table 4-3 summarizes the results from Scenario C. For comparative purposes, the actual results and the tested results are presented side by side. The "Filed" portion of the table summarizes the actual historical results from the quarterly filings while the "Tested" portion of the table shows the results that would have occurred had the Scenario C commodity rate adjustment trigger mechanism been used. Further, the "Net Impact" columns are provided to highlight the differences in deferral balances and rates between the two rate setting mechanisms.

Table 4-3: 90% to 110% Deadband

PERIOD	Filed					Tested					Net Impact	
	DEFERRAL BALANCE ($ million)	TRIGGER RATIO (%)	EXISTING LM RS 1 ($/GJ)	PROPOSED LM RS 1 ($/GJ)	LM RS 1 CHANGE ($/GJ)	DEFERRAL BALANCE ($ million)	TRIGGER RATIO (%)	EXISTING LM RS 1 ($/GJ)	PROPOSED LM RS 1 ($/GJ)	LM RS 1 CHANGE ($/GJ)	DEFERRAL BALANCE ($ million)	RATE CHANGE ($/GJ)
2004 Q4	$ 2	99.9	$ 7.005	$ 7.005	$ -	$ 2	99.9	$ 7.005	$ 7.005	$ -	$ -	$ -
2005 Q1	(6)	100.6	7.005	7.005	-	(6)	100.6	7.005	7.005	-	-	-
2005 Q2	71	91.5	7.005	7.658	0.653	71	91.5	7.005	7.005	-	-	(0.653)
2005 Q3	180	82.4	7.658	9.292	1.634	269	74.0	7.005	9.464	2.459	89	0.172
2005 Q4	52	95.0	9.292	9.774	0.482	29	97.3	9.464	9.464	-	(23)	(0.310)
2006 Q1	(227)	127.6	9.774	7.662	(2.112)	(183)	122.0	9.464	7.978	(1.486)	44	0.316
2006 Q2	3	99.6	7.662	7.662	-	(41)	105.1	7.978	7.978	-	(44)	0.316
2006 Q3	1	99.8	7.662	7.662	-	(41)	105.0	7.978	7.978	-	(43)	0.316
2006 Q4	12	98.6	7.662	7.662	-	(31)	103.7	7.978	7.978	-	(42)	0.316
2007 Q1	36	95.7	7.662	7.662	-	(9)	101.1	7.978	7.978	-	(45)	0.316
2007 Q2	1	99.8	7.662	7.662	-	(38)	105.0	7.978	7.978	-	(39)	0.316
2007 Q3	(95)	115.0	7.662	6.926	(0.736)	(135)	121.5	7.978	6.589	(1.389)	(40)	(0.337)
2007 Q4	7	99.0	6.926	6.926	-	46	93.1	6.589	6.589	-	39	(0.337)
2008 Q1	129	83.5	6.926	8.287	1.361	168	78.6	6.589	8.370	1.781	39	0.083
2008 Q2	142	84.7	8.287	9.780	1.493	133	85.8	8.370	9.757	1.387	(9)	(0.023)
2008 Q3	(214)	129.8	9.780	7.536	(2.244)	(212)	129.4	9.757	7.542	(2.215)	3	0.006
2008 Q4	13	98.1	7.536	7.536	-	13	98.1	7.542	7.542	-	-	0.006
2009 Q1	(136)	126.4	7.536	5.962	(1.574)	(136)	126.4	7.542	5.961	(1.581)	-	(0.001)
2009 Q2	(34)	107.5	5.962	5.962	-	(34)	107.5	5.961	5.961	-	-	(0.001)
2009 Q3	(91)	120.4	5.962	4.953	(1.009)	(91)	120.4	5.961	4.953	(1.008)	-	-
2009 Q4	25	95.2	4.953	4.953	-	25	95.2	4.953	4.953	-	-	-
2010 Q1	63	88.4	4.953	5.609	0.656	63	88.4	4.953	5.609	0.656	-	-
2010 Q2	(60)	112.7	5.609	4.976	(0.633)	(60)	112.7	5.609	4.976	(0.633)	-	-
2010 Q3	(32)	107.3	4.976	4.976	-	(32)	107.3	4.976	4.976	-	-	-
2010 Q4	(39)	109.1	4.976	4.568	(0.408)	(39)	109.1	4.976	4.976	-	-	0.408

*Deferral Balances shown in the table are the 12-Month Forecast Ending Deferral Balances grossed-up to reflect amounts flowed through for rate setting purposes.
*Grossed-up balances may contain slight differences due to rounding.

The trigger ratio of 91.5% in the 2005 second quarter review would not trigger a rate change under Scenario C. The Scenario C analysis then shows a larger increase in rates would result at 2005 third quarter review however no further rate increase would be triggered during the 2005 fourth quarter review, as occurred in the actual historical results.

After that point, the analysis shows that rate changes would occur at the same time, though for differing amounts, than the actual historical results show. Then, through the 2008 and first half of the 2009 periods the rate differences generated under Scenario C become very small compared to the actual historical results, with the commodity rate then becoming the same under both mechanisms at the 2009 third quarter review and remaining that way for the remainder of the period until the 2010 fourth quarter when the results under Scenario C support no rate change.

Theoretically the use of a ± 10% rate change trigger ratio should provide a greater degree of stability due to the wider deadband range. The Scenario C test results indicate that based on the underlying historical data used in the sample there would have been a few less rate changes during the six-year sample period however, the potential size of the deferral balances carried under a ± 10% rate change trigger ratio are an area of concern for the Company. The Scenario C alternative mechanism would be expected to provide a materially wider deadband during higher commodity price periods which could result in 12-month forecast ending deferral balances in excess of $50 million. This is demonstrated in the 2005 second quarter tested results shown in Table 4-3 where under Scenario C the rate change trigger ratio falls within the deadband range indicating rates should remain unchanged while the 12-month forecast ending deferral balance is forecast to build to a deficit of over $70 million.

4.4 Scenario D: $50 M Deficit to $50 M Surplus Deferral Balance Deadband

Scenario D tests the alternative of changing the trigger ratio from the existing ± 5% trigger ratio to a deferral balance dollar value based threshold such that the 12-month forecast ending deferral balance would be maintained within a ± $50 million deadband. In other words, under this scenario the 12-month forecast ending deferral balance is allowed to reach a threshold of either a $50 million surplus balance or a $50 million deficit balance before triggering a rate change.

Chart 4-4 displays the rate impact effects of the Scenario D alternative trigger ratio mechanism of a ± $50 million change threshold, based on the current CCRA gas volumes, compared to the effects of the existing trigger ratio of ± 5%, at various natural gas prices. The chart shows how the ± $50 million deadband basically remains flat regardless of changes in the average price of natural gas, though it should be noted that any significant fluctuations in the CCRA portfolio gas volumes would affect the unitized value of the ± $50 million threshold (which at the current CCRA gas volumes equates to a rate impact of approximately $0.52/GJ.

Chart 4-4: Rate Impact of ±$50 Million Trigger Ratio Compared to Existing ±5% Trigger Ratio

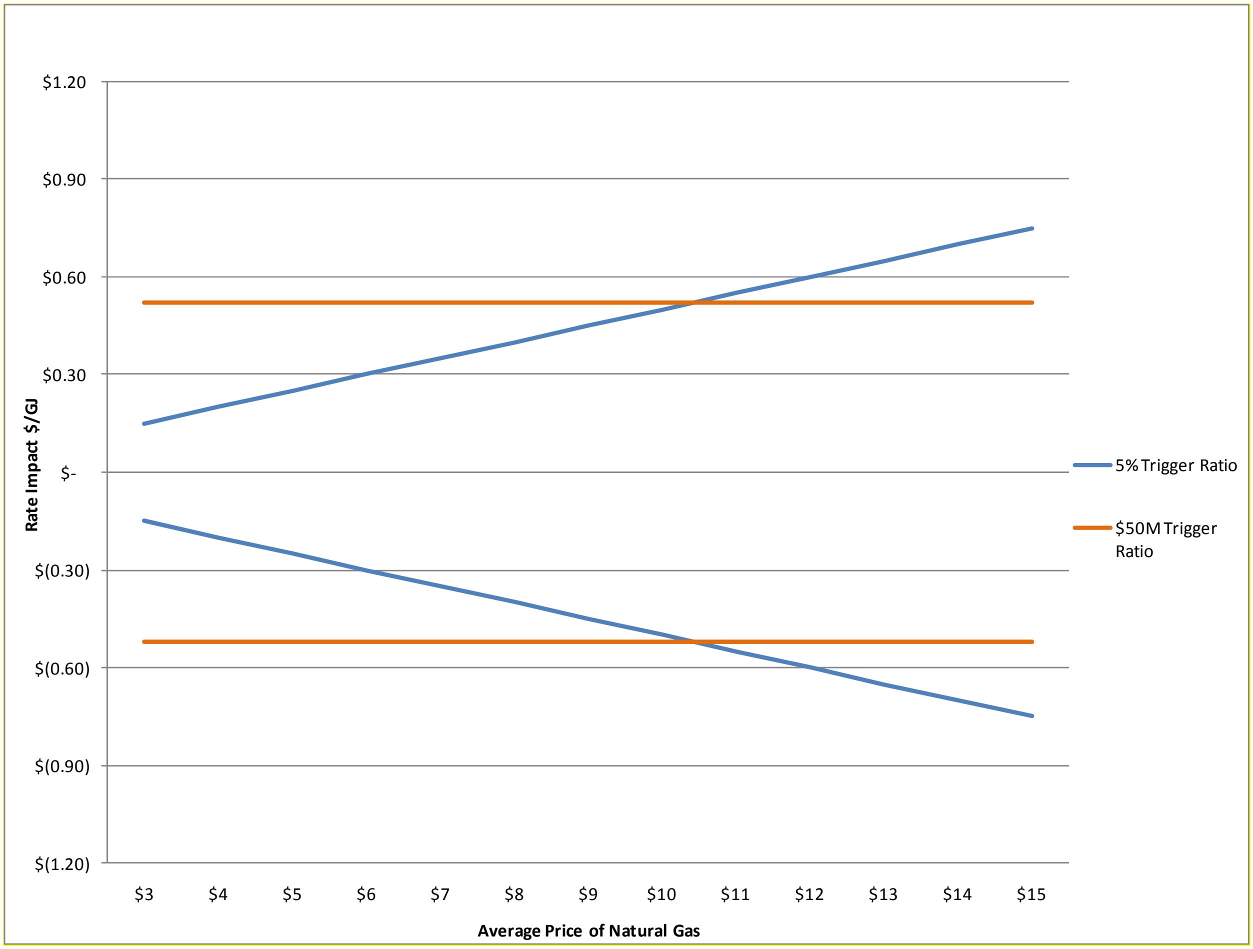


Table 4-4 summarizes the results from Scenario D. For comparative purposes, the actual results and the tested results are presented side by side. The "Filed" portion of the table summarizes the actual historical results from the quarterly filings while the "Tested" portion of the table shows the results that would have occurred had the Scenario D commodity rate adjustment trigger mechanism been used. Further, the "Net Impact" columns are provided to highlight the differences in deferral balances and rates between the two rate setting mechanisms.

Table 4-4: $50 M Deficit to $50 M Surplus Deferral Balance Deadband

PERIOD		Filed DEFERRAL BALANCE ($ million)	Filed TRIGGER RATIO (%)	Filed EXISTING LM RS 1 ($/GJ)	Filed PROPOSED LM RS 1 ($/GJ)	Filed LM RS 1 CHANGE ($/GJ)	Tested DEFERRAL BALANCE ($ million)	Tested TRIGGER RATIO (%)	Tested EXISTING LM RS 1 ($/GJ)	Tested PROPOSED LM RS 1 ($/GJ)	Tested LM RS 1 CHANGE ($/GJ)	Net Impact DEFFERAL BALANCE ($ million)	Net Impact RATE CHANGE ($/GJ)
2004	Q4	2	99.9	$ 7.005	$ 7.005	$ -	2	99.9	$ 7.005	$ 7.005	$ -	$ -	$ -
2005	Q1	(6)	100.6	7.005	7.005	-	(6)	100.6	7.005	7.005	-	-	-
2005	Q2	71	91.5	7.005	7.658	0.653	71	91.5	7.005	7.658	0.653	-	-
2005	Q3	180	82.4	7.658	9.292	1.634	180	82.4	7.658	9.292	1.634	-	-
2005	Q4	52	95.0	9.292	9.774	0.482	52	95.0	9.292	9.774	0.482	-	-
2006	Q1	(227)	127.6	9.774	7.662	(2.112)	(227)	127.6	9.774	7.662	(2.112)	-	-
2006	Q2	3	99.6	7.662	7.662	-	3	99.6	7.662	7.662	-	-	-
2006	Q3	1	99.8	7.662	7.662	-	1	99.8	7.662	7.662	-	-	-
2006	Q4	12	98.6	7.662	7.662	-	12	98.6	7.662	7.662	-	-	-
2007	Q1	36	95.7	7.662	7.662	-	36	95.7	7.662	7.662	-	-	-
2007	Q2	1	99.8	7.662	7.662	-	1	99.8	7.662	7.662	-	-	-
2007	Q3	(95)	115.0	7.662	6.926	(0.736)	(95)	115.0	7.662	6.926	(0.736)	-	-
2007	Q4	7	99.0	6.926	6.926	-	7	99.0	6.926	6.926	-	-	-
2008	Q1	129	83.5	6.926	8.287	1.361	129	83.5	6.926	8.287	1.361	-	-
2008	Q2	142	84.7	8.287	9.780	1.493	142	84.7	8.287	9.780	1.493	-	-
2008	Q3	(214)	129.8	9.780	7.536	(2.244)	(214)	129.8	9.780	7.536	(2.244)	-	-
2008	Q4	13	98.1	7.536	7.536	-	13	98.1	7.536	7.536	-	-	-
2009	Q1	(136)	126.4	7.536	5.962	(1.574)	(136)	126.4	7.536	5.962	(1.574)	-	-
2009	Q2	(34)	107.5	5.962	5.962	-	(34)	107.5	5.962	5.962	-	-	-
2009	Q3	(91)	120.4	5.962	4.953	(1.009)	(91)	120.4	5.962	4.953	(1.009)	-	-
2009	Q4	25	95.2	4.953	4.953	-	25	95.2	4.953	4.953	-	-	-
2010	Q1	63	88.4	4.953	5.609	0.656	63	88.4	4.953	5.609	0.656	-	-
2010	Q2	(60)	112.7	5.609	4.976	(0.633)	(60)	112.7	5.609	4.976	(0.633)	-	-
2010	Q3	(32)	107.3	4.976	4.976	-	(32)	107.3	4.976	4.976	-	-	-
2010	Q4	(39)	109.1	4.976	4.568	(0.408)	(39)	109.1	4.976	4.976	-	-	0.408

*Deferral Balances shown in the table are the 12-Month Forecast Ending Deferral Balances grossed-up to reflect amounts flowed through for rate setting purposes.
*Grossed-up balances may contain slight differences due to rounding.

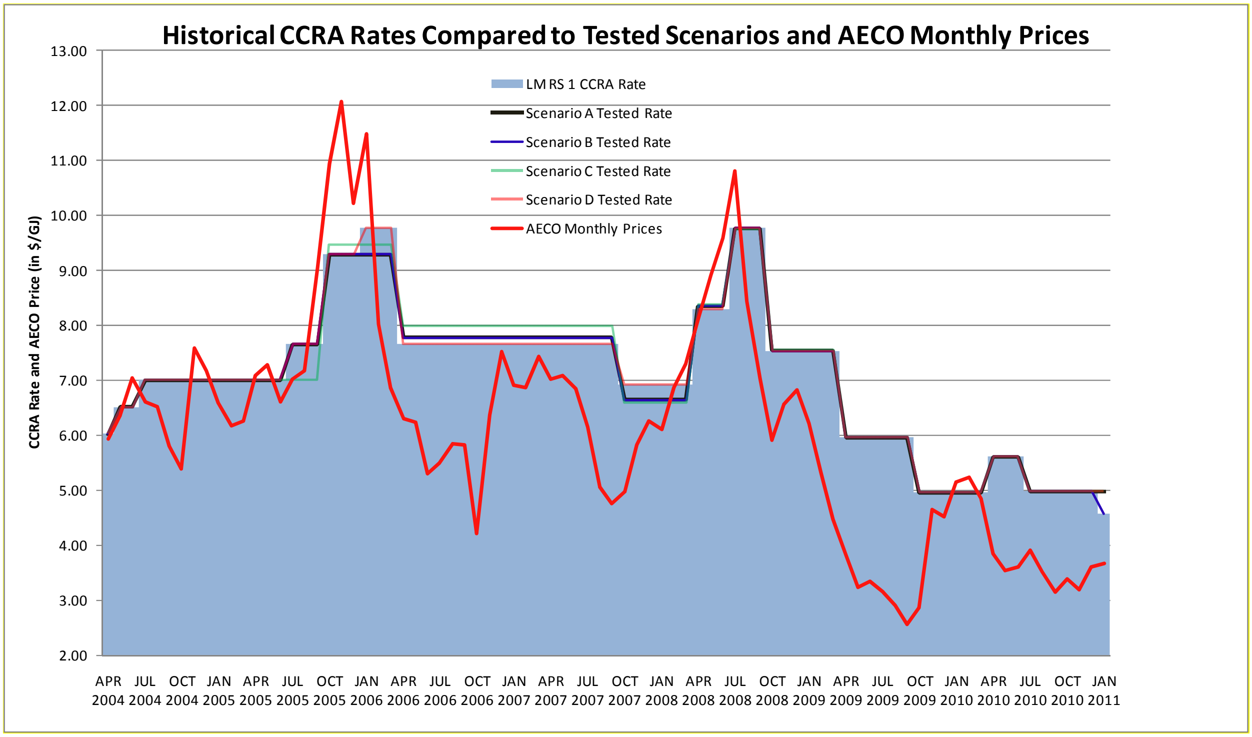
The Scenario D alternative rate adjustment mechanism of triggering a rate change when the 12-month forecast ending deferral balance falls outside the ± $50 million deadband, as tested and shown in Table 4-4, would produce rate change results which are basically the same as the historical results filed through the six-year test period until the 2010 fourth quarter when the results under Scenario D support no rate change.

The fact that the results are basically the same is not that surprising when one looks at the underlying historical data used in the sample. Over the sample period, the 12-month forecast ending deferral balance was outside the ± $50 million deadband in most instances that the trigger ratio was also outside the 95% to 105% deadband. Other than the 2010 fourth quarter period, the couple of instances within the sample period that the trigger ratio was outside the 95% to 105% deadband while the 12-month forecast ending deferral balance was within a ± $50 million deadband (specifically the 2009 second quarter period and the 2010 third quarter period) the existing CCRA rates were left unchanged.

4.5 CCRA Rate Adjustment Mechanism Recommendations

Chart 4-5 displays the historical CCRA rates, based on the Lower Mainland Rate Schedule 1 residential customer rates, that have been in effect since April 2004 compared to the rates determined from the tested results of the Scenario A through D alternative mechanisms. As well, the AECO actual monthly prices (in Canadian $/GJ) are shown on the chart.

Chart 4-5: Historical Effective CCRA Rate Compared to Tested Scenarios and AECO Montly Prices



In terms of rates, based on the historical sample data, each of the tested alternative trigger mechanisms produced rates that were not significantly different from those that were established using the existing rate change trigger mechanism. Again, the results are not that surprising considering the forecast gas costs to be recovered remains the same; that is, regardless of the alternative being tested, over the long run all the gas costs need to be recovered and whenever the CCRA rate is reset it is typically based on eliminating any imbalance in the CCRA deferral account at the end of the prospective 12-month period.

The various scenarios showed that although the timing of when a rate change was triggered and the amount of the rate change varied slightly between the alternatives, the rates ultimately follow the 12-month forecast average cost of gas in the CCRA portfolio. Further, based on the quarterly frequency of the review cycle any differences between the recovery rates and the forecast CCRA costs which may fall within the deadband tolerance during a current quarter's review would be subject to review again only three months later, thus ensuring any material disconnect between the recovery rates and the gas costs is identified and addressed.

FEI believes the existing 95% to 105% deadband has functioned well and that in light of the current lower price environment the addition of a second parameter of a minimum $/GJ rate change threshold value, as tested in Scenario A, would have the effect of keeping the deadband from becoming too narrow during periods when the price of natural gas remains low; thereby providing slightly more stability to the existing mechanism during low price environments for natural gas.

The Company recommends that the CCRA rate change trigger mechanism be changed to be the ± 5% trigger ratio plus a minimum rate change threshold of ± $0.50/GJ. This provides a balance of maintaining manageable deferral balances, providing appropriate price signals to customers, and avoidance of minor CCRA rate changes in low price environments.

Furthermore, the Company believes the commodity rate change trigger mechanism provides a strong indication of the appropriateness of the commodity recovery rate but believes that it is important, and not inconsistent with past practice, to give consideration to the full circumstances and that other criteria should be considered in the review of the commodity cost recovery rates. The Company believes that in addition to the trigger mechanism, which provides an indication of the appropriateness of rates based on the 12-month prospective view, consideration should also be given to factors such as the current deferral balance and, based on the forecast costs, the appropriateness of any rate proposals over the 24-month timeframe.

5 MCRA DEFERRAL ACCOUNT AND RATE SETTING MECHANISM

As discussed in Section 2 of this Report, the Company filed the Commercial Commodity Unbundling and Customer Choice Phase 1 Cost Allocation Application on January 16, 2004, wherein the Company requested approval for changes to the gas cost deferral account. Under the Essential Services Model it was necessary to separate the commodity costs from the midstream costs and accordingly, there was a need for two separate deferral accounts in place of the GCRA. The CCRA and MCRA were established effective April 1, 2004 pursuant to Commission Order No. G-25-04, dated March 12, 2004, and the Reasons for Decision attached as Appendix A to the Order.

On April 13, 2006, the Company filed the Commodity Unbundling Project for Residential Customers CPCN Application, wherein the Company requested approval for consistent application of the Essential Services Model and the CCRA and MCRA mechanisms, currently in practice for the Commercial Commodity Unbundling Program, for the Residential Commodity Unbundling Program. Commission approval was granted under Commission Order No. C-6-06, dated August 14, 2006.

The MCRA contains the midstream costs which comprise a mixture of costs which are fixed in nature and those which are variable in nature, and consistent with the existing gas cost rate design methodology, fixed costs are allocated to rate classes based on a load factor adjusted volumetric basis, while variable costs are allocated to rate classes based on a volumetric basis. Midstream cost recovery rates are reviewed quarterly as part of the FEI quarterly gas cost reports filed with the Commission however, under normal circumstances, the midstream rates (also referred to as the MCRA rates) are typically reset annually with a January 1st effective date.

It is important to note that the midstream function is responsible for balancing the supply and demand volumes of the entire gas supply portfolio. Unlike the CCRA, which is basically only subject to commodity price variances as it is based on a pre-established baseload volume, the MCRA is subject to price variances on all of its individual components as well as the volumetric variances between the forecast and the actual consumption for the entire gas supply portfolio. The result is that there is a significant degree of volatility inherent in the MCRA and the size of the year end deferral balance.

The volumetric consumption variances captured in the MCRA are a significant component of the year end deferral balance and are somewhat similar to the volumetric consumption variances captured in the Revenue Stabilization Adjustment Mechanism ("RSAM") deferral account. A primary driver of the volumetric consumption variances in both the RSAM and the MCRA is the difference between the normal weather used in calculating the forecast annual consumption versus the actual weather. Further, as the normal weather is based on the ten year average weather, it can be expected that over a multi-year time frame the range of the normal versus actual weather variances should tend to narrow when compared to the range that could occur in a single year period. In other words, as normal weather is based on the ten year average, over time it can be expected that weather variances from one year will tend to be offset by weather variances occurring in other years.

The standard practice in setting the midstream rate has been to set rates on a prospective 12-month basis such that the midstream rate effective January 1st recovers the forecast midstream costs for the next 12-month period and fully amortizes the current year's projected closing balance in the MCRA. The Company, for the purposes of the analysis within this Report, will refer to the component of the midstream rate calculated to recover the forecast midstream costs for the next 12-month period as the "MCRA Base Rate", and the component of the midstream rate calculated to amortize the current year's projected closing balance in the MCRA as the "MCRA Deferral Rate". Further, for the purposes of comparing the effects on the midstream rates under the alternative scenarios, the Residential Commodity Unbundling Rider, Rate Rider 8, which only became effective January 1, 2008, has been excluded from the Lower Mainland Rate Schedule 1 ("LM RS 1") "Approved" and "Tested" rates shown in the tables.

In the past few years, the closing deferral balances have swung from a $32 million deficit at December 31, 2007, to a $36 million surplus at December 31, 2008, and then to a $33 million deficit at December 31, 2009. The result, under the existing methodology of amortizing the full deferral balance through rates over the next 12-month period, has been a swing in the MCRA Deferral Rate applicable to a Lower Mainland residential customer from a recovery amount of $0.366/GJ in 2008 rates, to a refund amount of $0.341/GJ in 2009 rates, and back to a recovery amount of $0.312 in 2010 rates. In other words, the change in the Lower Mainland residential midstream rate effective in 2009 to the 2010 rate included the impact of a net change related only to the deferral amortization of over $0.65/GJ.

To assess the appropriateness of the existing methodology for the amortization of the current year's projected closing balance of the MCRA, the Company has tested an alternative amortization methodology based on the RSAM methodology of amortizing 1/3 of the current year's projected closing deferral balance in rates for the next 12-month period.

The following assumptions have been applied in preparing the MCRA alternative test scenarios:

1. The analysis included the impacts to the deferral balances, as shown in the tables, of changes to midstream cost recovery rates for all rate classes though, for presentation purposes, the tables compare only LM RS 1 residential customer rates.

2. The analysis was restricted to changes in the amortization of MCRA deferral balance and assumes all other factors remained unaffected by the changes in the midstream rates.

3. The analysis conducted utilized the historical quarterly gas cost data covering the five-year period from the 2005 Fourth Quarter Gas Cost Report, which established the midstream rates effective January 1, 2006, to the 2010 Fourth Quarter Gas Cost Report, which established the midstream rates effective January 1, 2011.

The subsections which follow provide the results of the analysis under the various scenarios, with each subsection summarizing the results produced under that particular tested scenario and comparing them to the historical results.

5.1 Scenario 1: 1/3 of Deferral Balance Amortized in 12-Month Rates

In setting midstream rates, the projected December 31st closing deferral balance has been fully amortized in the midstream rates over the next 12-month period. The first scenario examines the impact on midstream rates if the projected closing deferral balance at the end of the current period is not fully amortized in the next 12-month period but is amortized using an alternative methodology based on the RSAM model with only 1/3 of the closing balance being amortized in rates for the next 12-month period.

To demonstrate the impact of the Scenario 1 alternative approach, the historical data has been used to recalculate what the impact on midstream rates and on the MCRA closing deferral balance would have been if only 1/3 of the cumulative deferral balance at the end of each year was amortized into the next year's midstream rates.

Table 5-1 summarizes the results from Scenario 1. For comparative purposes, the actual results and the tested results are presented side by side. The "Filed" portion of the table summarizes the actual historical results from the fourth quarter filings while the "Tested Scenario 1" portion of the table shows the results that would have occurred had the Scenario 1 alternative MCRA deferral balance amortization methodology been used. Further, the "Net Impact" columns are provided to highlight the differences in deferral balances and rates between the two methods of rate-setting.

Table 5-1: 1/3 of Deferral Balance Amortized in 12-Month Rates – Historical Data

	Filed				Tested Scenario 1				Net Impact	
EFFECTIVE DATE	DEFERRAL BALANCE ($ million)	MCRA BASE RATE LM RS 1 ($/GJ)	MCRA DEFERRAL RATE LM RS 1 ($/GJ)	APPROVED RATE LM RS 1 ($/GJ)	DEFERRAL BALANCE ($ million)	MCRA BASE RATE LM RS 1 ($/GJ)	MCRA DEFERRAL RATE LM RS 1 ($/GJ)	TESTED RATE LM RS 1 ($/GJ)	DEFERRAL BALANCE ($ million)	RATE LM RS 1 ($/GJ)
Jan 01, 2006	$ (68)	$ 0.613	$ (0.606)	$ 0.007	$ (68)	$ 0.613	$ (0.202)	$ 0.411	$ -	$ 0.404
Jan 01, 2007	4	0.821	0.038	0.859	(3)	0.821	(0.010)	0.811	(8)	(0.048)
Jan 01, 2008	32	0.843	0.366	1.209	35	0.843	0.101	0.944	3	(0.265)
Jan 01, 2009	(36)	1.283	(0.341)	0.942	(16)	1.283	(0.049)	1.235	20	0.293
Jan 01, 2010	33	1.330	0.312	1.642	28	1.330	0.085	1.415	(5)	(0.227)
Jan 01, 2011	(7)	1.408	(0.068)	1.340	6	1.408	0.017	1.425	13	0.085

*Deferral Balances shown in the table are the projected December 31 year end amounts grossed-up to reflect amounts flowed through for rate setting purposes.

*Rates shown in the table are based on the Lower Mainland Rate Schedule 1 (LM RS 1) residential customer rates and exclude Rate Rider 8.

*Rate Rider 8, Residential Commodity Unbundling Rider, came into effect January 1, 2008.

*MCRA Deferral Rate of $(0.606)/GJ effective January 1, 2006 is shown in the table; the 2006 mid-year adjustment is not shown however the Deferral Balances shown in the table reflect all approved rate changes.

*Grossed-up balances may contain slight differences due to rounding.

Based on the historical results, as shown in the Tested Scenario 1 results, lengthening the amortization period of the closing balance in the MCRA by amortizing only 1/3 of the balance in the next year's midstream rates dampens the rate impacts related to the deferral balance.

Further, it is expected that the component of the annual MCRA variances caused by warmer or colder than normal weather will tend to offset themselves over the longer term.

5.2 Scenario 2: 1/3 of Deferral Amortized Under Back-to-Back Deficits

The second scenario repeats the same basic alternative approach of amortizing 1/3 of the cumulative deferral balance at the end of each year into the next year's midstream rates as was tested in the Scenario 1 analysis but the Scenario 2 analysis tests "what if" the MCRA deferral account experienced three years of consecutive annual deficit activity.

Due to the nature of the swings in the historical ending deferral balances from a deficit at the end of 2007, to a surplus at the end of 2008, and back to a deficit at the end of 2009, the impacts of the alternative amortization methodology under Scenario 1 are very favorable. The historical data provides a relatively small sample and it is felt that with a larger data sample it would not be inconceivable to experience a build-up of the deficit in the MCRA deferral account as a result of back-to-back deficits.

Table 5-2 summarizes the results from Scenario 2. For comparative purposes, the Scenario 1 tested results and the Scenario 2 tested results are presented side by side. The "Tested Scenario 1" portion of the table summarizes the Scenario 1 results that are based on the historical data while the "Tested Scenario 2" portion of the table shows the results that would have occurred based on a "what if" scenario where annual deficit activity occurs for three consecutive years and the 1/3 alternative MCRA deferral balance amortization methodology is used. Further, the "Net Impact" columns are provided to highlight the differences in deferral balances and rates between the two scenarios.

Table 5-2: 1/3 of Deferral Balance Amortized in 12-Month Rates – Consecutive Deficits

	Tested Scenario 1				Tested Scenario 2				Net Impact	
EFFECTIVE DATE	DEFERRAL BALANCE ($ million)	MCRA BASE RATE LM RS 1 ($/GJ)	MCRA DEFERRAL RATE LM RS 1 ($/GJ)	TESTED RATE LM RS 1 ($/GJ)	DEFERRAL BALANCE ($ million)	MCRA BASE RATE LM RS 1 ($/GJ)	MCRA DEFERRAL RATE LM RS 1 ($/GJ)	TESTED RATE LM RS 1 ($/GJ)	DEFERRAL BALANCE ($ million)	RATE LM RS 1 ($/GJ)
Jan 01, 2007	$ (3)	$ 0.821	$ (0.010)	$ 0.811	$ (3)	$ 0.821	$ (0.010)	$ 0.811	$ -	$ -
Jan 01, 2008	35	0.843	0.101	0.944	35	0.843	0.101	0.944	-	-
Jan 01, 2009	(16)	1.283	(0.049)	1.235	56	1.283	0.177	1.460	72	0.225
Jan 01, 2010	28	1.330	0.085	1.415	75	1.330	0.228	1.558	47	0.143
Jan 01, 2011	6	1.408	0.017	1.425	38	1.408	0.113	1.521	32	0.096

*Deferral Balances shown in the table are the projected December 31 year end amounts grossed-up to reflect amounts flowed through for rate setting purposes.
*Rates shown in the table are based on the Lower Mainland Rate Schedule 1 (LM RS 1) residential customer rates and exclude Rate Rider 8.
*Rate Rider 8, Residential Commodity Unbundling Rider, came into effect January 1, 2008.
*Grossed-up balances may contain slight differences due to rounding.

The Tested Scenario 2 results are not based on the actual historical data but rather show the deferral and rate impact of three consecutive years of deficit activity in the MCRA. The scenario is not meant to be representative of an expected outcome but of a possible severe under recovery case; over time, the weather related annual MCRA variances would be expected to be offset as the long term weather will trend to normal. The results demonstrate how the 1/3 alternative MCRA deferral balance amortization methodology effectively dampens the rate impacts related to the deferral balance; under the Tested Scenario 2 results, the midstream rate at each of the back to back deficit years is lower than the approved midstream rate effective January 1, 2010. However, should such a situation as tested in Scenario 2 ever present itself, consideration would have to be given to the magnitude of the deferral balance and possible acceleration of the recovery of the deficit as the Tested Scenario 2 results show the deferral balance reaching a deficit of approximately $75 million.

5.3 Scenario 3: 1/3 of Deferral Amortized Under Back-to-Back Surpluses

The third scenario repeats the same basic alternative approach of amortizing 1/3 of the cumulative deferral balance at the end of each year into the next year's midstream rates as was tested in the Scenario 1 analysis but, instead of testing the "what if" scenario of consecutive annual deficit activity as was done in Scenario 2, the Scenario 3 analysis tests "what if" the MCRA deferral account experienced three years of consecutive annual surplus activity.

As discussed in subsection 5.2, the nature of the swings in the historical ending deferral balances from a deficit at the end of 2007, to a surplus at the end of 2008, and back to a deficit at the end of 2009, yield very favorable results under the Scenario 1 analysis. The historical data provides a relatively small sample and with a larger data sample it would not be inconceivable to experience a large surplus build in the MCRA deferral account as a result of back-to-back surpluses

Table 5-3 summarizes the results from Scenario 3. For comparative purposes, the Scenario 1 tested results and the Scenario 3 tested results are presented side by side. The "Tested Scenario 1" portion of the table summarizes the Scenario 1 results that are based on the historical data while the "Tested Scenario 3" portion of the table shows the results that would have occurred based on a "what if" scenario where annual surplus activity occurs for three consecutive years and the 1/3 alternative MCRA deferral balance amortization methodology is used. Further, the "Net Impact" columns are provided to highlight the differences in deferral balances and rates between the two scenarios.

Table 5-3: 1/3 of Deferral Balance Amortized in 12-Month Rates – Consecutive Surpluses

	Tested Scenario 1				Tested Scenario 3				Net Impact	
EFFECTIVE DATE	DEFERRAL BALANCE ($ million)	MCRA BASE RATE LM RS 1 ($/GJ)	MCRA DEFERRAL RATE LM RS 1 ($/GJ)	TESTED RATE LM RS 1 ($/GJ)	DEFERRAL BALANCE ($ million)	MCRA BASE RATE LM RS 1 ($/GJ)	MCRA DEFERRAL RATE LM RS 1 ($/GJ)	TESTED RATE LM RS 1 ($/GJ)	DEFERRAL BALANCE ($ million)	RATE LM RS 1 ($/GJ)
Jan 01, 2007	$ (3)	$ 0.821	$ (0.010)	$ 0.811	$ (3)	$ 0.821	$ (0.010)	$ 0.811	$ -	$ -
Jan 01, 2008	35	0.843	0.101	0.944	(29)	0.843	(0.085)	0.758	(64)	(0.186)
Jan 01, 2009	(16)	1.283	(0.049)	1.235	(59)	1.283	(0.185)	1.099	(44)	(0.136)
Jan 01, 2010	28	1.330	0.085	1.415	(66)	1.330	(0.200)	1.130	(94)	(0.285)
Jan 01, 2011	6	1.408	0.017	1.425	(59)	1.408	(0.177)	1.231	(65)	(0.194)

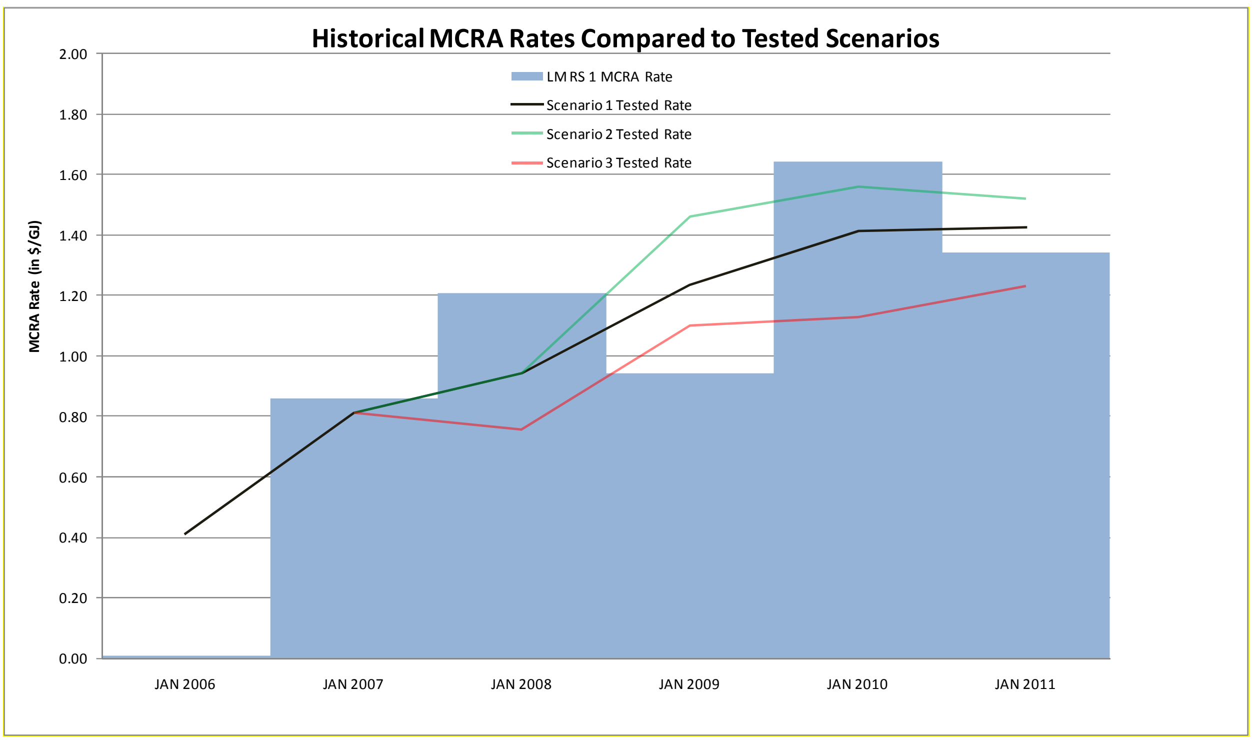
*Deferral Balances shown in the table are the projected December 31 year end amounts grossed-up to reflect amounts flowed through for rate setting purposes.
*Rates shown in the table are based on the Lower Mainland Rate Schedule 1 (LM RS 1) residential customer rates and exclude Rate Rider 8.
*Rate Rider 8, Residential Commodity Unbundling Rider, came into effect January 1, 2008.
*Grossed-up balances may contain slight differences due to rounding.

The Tested Scenario 3 results are not based on the actual historical data but rather show the deferral and rate impact of three consecutive years of surplus activity in the MCRA. The scenario is not meant to be representative of an expected outcome but of a possible severe over recovery case; over time, the weather related annual MCRA variances would be expected to be offset as the long term weather will trend to normal. The results demonstrate how the 1/3 alternative MCRA deferral balance amortization methodology effectively dampens the rate impacts related to the deferral balance; under the Tested Scenario 3 results, the midstream rate at each of the back to back surplus years is less volatile than the approved midstream rate has been over that same time period. However, should such a situation as tested in Scenario 3 ever present itself, consideration would have to be given to the magnitude of the deferral balance and possible acceleration of the refund of the surplus as the Tested Scenario 2 results show the deferral balance reaching a surplus of approximately $66 million.

5.4 MCRA Rate Adjustment Mechanism Recommendations

Chart 5-1 displays the historical MCRA rates, based on the LM RS 1 residential customer rates, that have been in effect since January 1, 2006 compared to the rates determined from the tested results of the Scenario 1 alternative mechanism, and the tested results under the Scenario 2 consecutive deficit and Scenario 3 consecutive surplus "what if" scenarios.

Chart 5-1: Historical Effective MCRA Rate Compared to Tested Scenarios



In terms of rates, based on the historical sample data, the tested Scenario 1 alternative amortization methodology provides a greater level of rate stability than the current methodology. Amortizing 1/3 of the cumulative MCRA deferral balance at the end of each year has the net effect of dampening the year-to-year rate change impacts by elongating the amortization period related to any individual year's deficit or surplus and by smoothing the annual weather-related MCRA variances. Over a multi-year period the annual weather variations would be expected to offset themselves as the weather will trend to normal over the long run.

The Company believes the existing MCRA rate setting mechanism has functioned well in the past but that some of the recent year-to-year volatility in the midstream rates can be reduced by adoption of the alternative amortization methodology of amortizing 1/3 of the cumulative MCRA deferral balance at the end of each year into the next year's midstream rates. Although this effectively lengthens the recovery / refund period related to deficit / surplus balances, the Company believes the benefits provided by the additional rate stability support such a change. Further, all Sales customers pay midstream rates and only those customers electing to receive service under a Transportation Service tariff or discontinuing gas service would escape payment of the midstream rate and any recovery / refund of deficit / surplus activity related to prior periods.

In summary, the Company recommends that the MCRA rate setting mechanism be revised so that, under normal circumstances, only 1/3 of the projected cumulative MCRA deferral balance at the end of each year be amortized in the next year's rates, similar to the RSAM mechanism. The Company believes this is appropriate as the MCRA for gas costs, similar to the RSAM for delivery margin, captures the volumetric consumption variances.

Furthermore, the Company believes that along with the recommended revision to the MCRA rate setting mechanism it is important that consideration be given to the full circumstances in establishing rates, including such factors as the current deferral balance, the appropriateness of the amortization of the deferral balance, and the appropriateness of any rate proposals over the 24-month timeframe.

6 SUMMARY

In summary, the Company believes the results of its review validate that the current CCRA and MCRA quarterly review and rate setting mechanisms, consistent with the Commission established Guidelines, have functioned appropriately up to now and continue to provide a strong base from which to build.

Of significant note, the review of the CCRA and MCRA deferral accounts and rate setting mechanisms, and in particular the CCRA mechanism, has been conducted based on the existing gas supply portfolio which includes the historical hedging within the CCRA. At the time of this submission, the Company had filed on a confidential basis the results of the Commission directed review of the Price Risk Management Plan objectives, its recommendations for an enhanced hedging strategy, and had also filed its 2011 PRMP. Pursuant to Commission Order No. G-23-11, dated February 22, 2011, the 2011 PRMP objectives will be examined by way of a written public hearing process. The Company emphasizes that any material changes to the hedging within the CCRA portfolio could materially affect the variability between forecast and actual CCRA gas costs and subsequent deferral balances. While this outcome could result in more frequent commodity rate changes, the Company believes the quarterly review and proposed mechanisms are still appropriate.

The Company also believes that the following recommended minor improvements will serve to further improve the quarterly review and rate setting mechanisms, thereby benefiting customers through reduction of the frequency of minor rate changes while still providing appropriate price signals:

1. Commodity Price Forecasts – the Company supports the continued use of the NYMEX natural gas commodity futures, and recommends that a five-day average of forward prices taken on consecutive market dates be utilized in the determination of the gas cost forecasts for the quarterly review and resetting of rates.
2. CCRA Deferral Account and Rate Setting Mechanism – the Company supports the continued use of the existing ± 5% trigger ratio, and recommends the addition of a secondary parameter of a minimum $0.50/GJ rate change threshold value to enhance the effectiveness of the trigger mechanism utilized to evaluate the appropriateness of the commodity cost recovery rate on a quarterly basis.
3. MCRA Deferral Account and Rate Setting Mechanism – the Company recommends the annual midstream rate setting methodology be revised to include amortizing only 1/3 of the year end cumulative MCRA deferral balance in the following year's rates.

Furthermore, the Company believes the Guidelines are meant to be guidelines and provide valid mechanisms for the review and resetting of appropriate recovery rates. However, the Company believes that it is important, and not inconsistent with past practice, to give consideration to the full circumstances in establishing rates, including such factors as the current deferral balance and the appropriateness of any rate proposals over the 24-month timeframe.

The Company looks forward to working with Commission staff towards an efficient review of the attached report and the implementation of any changes to the Guidelines.

Appendix A

COMMISSION ORDER NO. L-5-01

ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

LETTER NO. L-5-01

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Log Nos. 5109,5013,4512,4523,4513

VIA FACSIMILE

February 5, 2001

Mr. David M. Masuhara
Vice President
Legal, Regulatory & Logistics
BC Gas Utility Ltd.
24th Floor, 1111 West Georgia Street
Vancouver, B.C. V6E 4M4

Dear Mr. Masuhara:

Re: BC Gas Utility Ltd.
Guidelines for Setting Gas Recovery Rates
and Managing the Gas Cost Reconciliation Balance

Until recently, gas cost recovery rates for BC Gas were set once per year effective January 1st. In 1999 and 2000, however, gas prices increased dramatically and mid-year rate changes were required. The difference between revenue from the gas cost recovery rates and gas costs incurred accumulates in the Gas Cost Reconciliation Account ("GCRA") and is paid back to BC Gas or refunded to customers in subsequent years. The rising gas prices in the last few years resulted in gas costs that were higher than rate revenue and led to a GCRA balance estimated at around $180 million at the end of 2000.

Due to concerns about the mid-year rate increases and the large GCRA balance, the Commission asked its staff to prepare a report on the method of establishing gas cost recovery rates for BC Gas and amortizing the GCRA balance. The staff report was circulated to BC Gas and other parties on November 7, 2000. BC Gas and four other parties responded with comments.

Based on its review of the staff report and the submissions made by BC Gas and the other parties, the Commission has decided to request quarterly reports from BC Gas and establish the attached Guidelines for Setting Gas Recovery Rates and Managing the GCRA Balance ("the Guidelines"). Although the Guidelines were developed with specific reference to BC Gas, the Commission believes that the Guidelines will also be appropriate for other provincial gas utilities.

Yours truly,

Original signed by:

Robert J. Pellatt

MAG/mmc
Attachment
cc: Mr. C.P. Donohue, Director
Regulatory Affairs & Gas Supply
Pacific Northern Gas Ltd.
Mr. I.D. Anderson
Vice President, Finance
Centra Gas British Columbia Inc.
Mr. R.T. O'Callaghan
R.T. O'Callaghan & Associates Inc.

Mr. R.J. Gathercole
Executive Director
B.C. Public Interest Advisory Centre
Mr. S. Yallouz
Vice President
PremStar Pacific

BCG/Cor/GCRA Guidelines

BRITISH COLUMBIA UTILITIES COMMISSION

Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance

---

1.0 Background

BC Gas Utility Ltd. ("BC Gas") purchases gas on behalf of its sales customers and passes these costs through to sales customers without markup. Costs related to the gas commodity are recovered from customers through gas cost recovery rates. Since rates are based on forecast costs and actual costs invariably differ from forecast costs, the Gas Cost Reconciliation Account ("GCRA") was established to accumulate the difference between the cost incurred by BC Gas to purchase the gas commodity and the revenue collected by BC Gas through the gas cost recovery rates.

Until recently, gas cost recovery rates were established once per year effective January 1 based on forecast costs for the upcoming year. In 1999 and 2000, however, gas costs were much higher than forecast and mid-year increases were sought by BC Gas and approved by the Commission effective September 1, 1999 and July 1, 2000 to reduce the under-recovery of gas costs. Even with the mid-year rate increases, the GCRA balance moved from a net credit balance (gas cost recovery revenue exceeded gas costs incurred) to a net debit balance (related costs exceeded gas cost recovery revenue) of around $180 million by the end of 2000.

The general rule for dealing with the GCRA balance has been to amortize it over three years through Rate Rider 6. A net debit balance results in a positive rate rider and higher effective gas cost recovery rates, while a net credit balance results in a negative rate rider and lower effective gas cost recovery rates. BC Gas has, in the past, been directed by the Commission to deviate from the rule and use the net credit GCRA balances to offset future rate increases to the greatest extent possible.

Due to concerns about the large rate increases, the discretionary nature of the two mid-year corrections and the lack of opportunity for customers to comment on or plan for the mid-year rate changes, the Commission asked its staff to provide a report on the method of establishing gas cost recovery rates for BC Gas, the method of amortizing the GCRA and alternate GCRA and gas cost commodity rate setting methods used in other jurisdictions. The staff report also discussed the various attributes of deferral account and rate setting methodologies including rate stability, price transparency, implications for the expected size of the deferral account and efficiency of process.

On November 7, 2000, the Commission circulated the report and invited feedback from utilities, customers and other stakeholders with the intent of preparing guidelines for gas cost recovery rate setting procedures for BC Gas. Parties were encouraged to comment on the suitability of BC Gas' gas cost recovery rate setting process and GCRA methodology given the current volatile and high price environment, as well as the merits of alternative processes. The issue was also raised at BC Gas' Annual Review on November 21, 2000.

Based on this process, the Commission has decided to request quarterly reports from BC Gas and establish Guidelines for Setting Gas Recovery Rates and Managing the GCRA Balance ("the Guidelines"). The Guidelines set out the conditions under which the Commission will generally expect BC Gas to file applications for changes to commodity cost recovery rates and the method of amortizing the GCRA balance.

The Guidelines are intended as a general guide only. Nothing in the Guidelines precludes BC Gas from filing applications for rate changes at times other than those implied by the Guidelines or proposing alternate treatment of the GCRA balance in unusual circumstances. Similarly, nothing in the Guidelines precludes the Commission from requesting rate applications at times other than those implied by the Guidelines.

Although the Guidelines were developed with specific reference to BC Gas, the Commission believes that the Guidelines will also be appropriate for other gas utilities.

2.0 Analytical Framework and Stakeholder Comments

The staff report discussed the various attributes of deferral account and rate setting methodologies including rate stability, price transparency, implications for the expected size of the deferral account and administrative requirements. These attributes provide a framework for analyzing proposed deferral account and gas cost rate setting methodologies and are described in Appendix II.

The Commission received comments on the staff report from BC Gas and four other parties. A summary of the comments is provided in Appendix III.

3.0 Determination

The Commission's preferences with respect to discretion in rate changes, the frequency of rate adjustments and the amortization period for the GCRA balance are outlined below.

Discretion in Rate Changes

BC Gas has proposed adjustments to gas cost recovery rates based on a pre-defined formula. The Commission is of the view that a mechanistic, formula-driven process of establishing gas cost recovery rates could lead to volatility in rates if 12 month gas cost forecasts vary significantly from month to month or quarter to quarter. The Commission is also concerned that setting rates based on a formula could result in undesirable rate changes and make it difficult to adapt to changing circumstances. This is of particular importance for the near future since the cost of energy from natural gas is now similar to the cost of energy from electricity and oil. For these reasons, the Commission finds that setting rates based on a pre-defined formula would be inappropriate at this time, and that BC Gas and the Commission should retain discretion in terms of the gas cost recovery rates applied for and approved.

Frequency of Rate Changes

The Commission is of the view that the current procedure of setting gas cost rates once per year with mid-year adjustments on an as required basis is no longer appropriate. However, a monthly process could lead to overly frequent rate changes and rate oscillations that impede, rather than improve, the price signal to customers, and would involve a great deal of administrative effort by both BC Gas and the Commission. The Commission also believes that while more frequent processes should generally reduce the size of required rate changes, even monthly adjustments would not prevent very large rate increases if gas costs change rapidly as they have over the last two years.

The Commission finds that a quarterly process for adjusting gas cost rates would provide a good price signal to customers, would help to reduce the size of the required rate changes, would help to keep the GCRA to manageable levels, and would be less onerous administratively. Accordingly, the Commission prefers a quarterly adjustment process rather than a monthly process as proposed by BC Gas.

Mechanism for Changes to Gas Rates

BC Gas and the Consumers' Association of Canada (B.C. Branch) et al. ("CAC (BC) et al.") proposed that the intra-year rate changes would be triggered by certain conditions. BC Gas suggested that changes be required if the difference between projected gas costs over the next 12 months and projected rate revenue over the next 12 months plus the GCRA balance (excluding the 2000 year-end balance) exceeds $50 million. The CAC (BC) et al. suggested that rates should be adjusted if the forecast under-recovery or over-recovery exceeds 5-10 percent of the forward gas bill.

The Commission agrees with BC Gas and the CAC (BC) et al. that intra-year rate adjustments should not occur if expected rate revenue is sufficiently close to expected gas costs. **The Commission believes that a rate adjustment should be triggered if the ratio of expected 12 month gas cost recovery revenue to the sum of the expected 12 month gas cost and the GCRA accumulated starting January 1, 2001 is less than 0.95 or more than 1.05. For the purposes of this calculation, gas cost recovery revenue would include gas cost rate revenue, gas cost mitigation revenue and revenue from the GCRA rider (except amounts related to**

the 2000 year-end GCRA balance). Gas costs would include the impact of hedging and the cost of storage.

For example, if the expected cost of gas for the next 12 months were $1,200 million and the GCRA debit balance were $50 million, BC Gas would file for a quarterly adjustment if expected gas cost recovery revenue were less than 0.95 X ($1,200 million + $50 million) = $1,188 million or more than 1.05 X ($1,200 million + $50 million) = $1,313 million.

The 5 percent trigger recommended by the Commission is at the lower end of the range suggested by the CAC (BC) et al. and is slightly higher than the trigger suggested by BC Gas based on current gas costs. The 5 percent trigger could be lower than BC Gas' trigger point if forecast gas costs fall significantly.

The Commission expects that the trigger mechanism would be applied to rate changes for the second, third and fourth quarters only. That is, the Commission expects that BC Gas will continue to file a comprehensive commodity rate application for the first quarter of each year (effective January 1).

Amortization of the GCRA Balance

BC Gas proposed to amortize the initial GCRA balance over the period from January 1, 2001 to October 30, 2002, which is the anticipated date for commodity unbundling. It appears that incremental GCRA amounts would be amortized over one year based on BC Gas' proposal. The CAC (BC) et al. indicates that a one year amortization period would generally be desirable, but that a two year amortization period may be required initially due to the current high GCRA balance. R.T. O'Callaghan and PremStar Pacific support amortization periods of no longer than one year.

The Commission finds that amortization of the GCRA balance over a one year period would be reasonable in normal circumstances. The Commission is concerned, however, about the impact of significant increases to the Rate Rider on customers already facing very high rates at this time. The Commission, in Order No. G-124-00, directed BC Gas to amortize one-third of the projected GCRA balance at December 31, 2000 through rates in 2001. In order to avoid potential rate shock associated with faster amortization of the entire balance, the Commission still finds that appropriate. The Commission expects that GCRA amounts accumulated starting January 1, 2001 will be amortized over a one year period in normal circumstances.

4.0 Reporting Requirements

To keep the Commission informed on expected gas costs, expected revenue from gas cost recovery rates and the GCRA balance, the Commission requests that BC Gas provide quarterly reports by the fifth business day of the month preceding each quarter (March, June, September and December). The Commission anticipates that the quarterly reports would include the following:

PREVIOUS QUARTER

- Actual GCRA balance at the start of the quarter
- Actual gas costs incurred in the quarter (including impact of hedging, storage, etc)
- Actual revenue from gas cost recovery rates and cost mitigation revenue in the quarter
- Actual revenue from Rate Rider 6 in the quarter
- Actual GCRA balance at the end of the quarter
- Explanation of significant differences between the above values and the forecasts for this quarter in the prior quarterly report

CURRENT QUARTER

Actual GCRA balance at the start of the quarter

Estimated gas costs incurred in the quarter (including impact of hedging, storage, etc)

Estimated revenue from gas cost recovery rates and cost mitigation revenue in the quarter

Estimated revenue from Rate Rider 6 in the quarter

Estimated GCRA balance at the end of the quarter

Explanation of significant differences between the above values and the forecasts for this quarter in the prior quarterly report

EACH OF THE NEXT FOUR QUARTERS STARTING ON THE FIRST DAY OF THE NEXT MONTH

Estimated GCRA balance at the start of the quarter

Estimated gas costs incurred in the quarter (including impact of hedging, storage, etc)

Estimated revenue from gas cost rates and cost mitigation revenue in the quarter based on both current and proposed rates

Estimated revenue from Rate Rider 6 in the quarter

Estimated GCRA balance at the end of the quarter based on both current and proposed gas cost recovery rates

OUTLOOK FOR THE FOLLOWING YEAR (COMMENCING 13 MONTHS FROM FILING DATE)

Estimated GCRA balance at the start of the year based on both current rates and the rates proposed for the upcoming quarter

Estimated gas costs incurred in the year (including impact of hedging, storage, etc)

Estimated revenue from gas cost rates and cost mitigation revenue in the year based on both current rates and the rates proposed for the upcoming quarter

Estimated revenue from Rate Rider 6 in the year

Estimated GCRA balance at the end of the year based on both current rates and the rates proposed for the upcoming quarter

The most recent forecast may be substituted if actual data is unavailable.

5.0 Guidelines for Setting Gas Recovery Rates and Managing the GCRA Balance

A. BC Gas normally files a revenue requirements application in the fourth quarter of every year to establish rates effective January 1 of the following year. BC Gas is expected to file for quarterly gas cost recovery rate changes if the ratio of expected 12 month gas cost recovery revenue to the sum of expected gas costs for the upcoming 12 month period plus the GCRA balance accumulated starting January 1, 2001 is less than 0.95 or greater than 1.05. For the purposes of this calculation, gas cost recovery revenue would include gas cost rate revenue, gas cost mitigation revenue and revenue from the GCRA rider (except amounts related to the 2000 year-end GCRA balance). Gas costs would include the impact of hedging and the cost of storage. Applications for quarterly rate changes should be made with the quarterly reports by the fifth business day of the month preceding the affected quarter. Quarterly rate adjustments would be effective April 1, July 1 and October 1.

B. BC Gas will retain its discretion in terms of the rate changes requested in any application. The Commission will continue to use its discretion in approving rate changes.

C. Due to the high initial balance and the already high rates faced by customers, the GCRA balance as at December 31, 2000 will continue to be amortized over three years. GCRA amounts accumulated starting January 1, 2001 will be amortized over a one year period in normal circumstances. Proposed changes to Rate Rider 6 will be included as part of the application to change gas cost recovery rates.

Nothing in the Guidelines precludes BC Gas from filing applications for rate changes at times other than those suggested by the Guidelines or proposing alternate treatment of the GCRA balance in unusual circumstances. Similarly, nothing in the Guidelines precludes the Commission from requesting rate applications at times other than those implied by the Guidelines.

Although the Guidelines were developed with specific reference to BC Gas, the Commission believes that the Guidelines will also be appropriate for other gas utilities in similar situations.

ATTRIBUTES OF DEFERRAL ACCOUNT AND GAS COST RATE SETTING METHODOLOGIES

Rate Stability

Rate stability refers to both the frequency and the size of rate changes. Customers would generally prefer rate changes to be smaller rather than larger and fewer rather than more, but these goals may conflict if there is a persistent upward or downward trend in gas costs.

Price Transparency

Price transparency refers to whether the gas cost recovery rates reflect market conditions and the overall accuracy of the price signal provided to customers. Setting rates annually generally provides a directionally correct price signal, but rate changes may be too infrequent to provide customers with a good idea of current gas price trends. Setting rates monthly or quarterly provides more frequent feedback, but may lead to oscillations that mask the underlying trend. It may be possible to reduce rate oscillation by setting rates based on the expected cost of gas over the next year rather than the expected cost in the next month or quarter.

Size of Deferral Account

In general, a mechanism that results in relatively small deferral account balances would be preferred to a mechanism that results in relatively large deferral account balances because large deferral accounts can mask underlying commodity price changes and alter the competitive position of the utility relative to smaller gas marketers. Large deferral accounts can also create issues related to the applicability of GCRA rate riders to new customers or customers switching to transportation service that might be avoidable or less important with smaller deferral account balances.

Efficiency of Process

Deferral account and gas cost recovery rate setting mechanisms that are relatively simple are preferred to those that are complex and difficult to understand, and adjustment mechanisms that involve less administration may be preferred to those that involve more administration. Annual review processes may tend to consume fewer resources than more frequent review processes unless the more frequent adjustments are accomplished mechanistically without the need for public input.

SUMMARY OF COMMENTS RECEIVED FROM BC GAS UTILITY LTD. AND OTHER PARTIES

BC Gas Utility Ltd.

BC Gas provided initial comments in a letter dated December 13, 2000. BC Gas indicated that it supports the implementation of a formula-based monthly review process. Rates would be changed at the end of a month if the projected cost of gas for the next 12 months less expected rate revenue for the same period plus the GCRA balance (excluding the initial GCRA balance) exceeds (or is lower than) by $50 million (approximately $65 per customer, or 4.4 percent). BC Gas proposed that rates would be set by formula commensurate with expected costs over the twelve month period. Based on BC Gas' proposal, rates would not change if gas costs are relatively stable, but could be expected to change most months if gas costs are trending upwards or downwards. BC Gas proposes to amortize the initial GCRA so that the fund is eliminated by October 31, 2002, the date of commodity unbundling. BC Gas also suggests that if gas prices fall prior to 2002, customer rates should not be reduced until the GCRA balance is reduced to negative $50 million.

BC Gas believes that the proposed monthly process would help to prevent a large accumulation in the GCRA account, would improve the price signal to customers and reduce the intergenerational inequity caused by large GCRA accounts. BC Gas suggests that the automatic adjustment mechanism would require limited public input and consume fewer resources at the Commission and BC Gas. BC Gas believes that sensitivity regarding frequent rate adjustments will likely be tempered by the increased public understanding of the commodity pricing of natural gas. BC Gas also indicates that slow recovery of large deferral account balances may be perceived by financial markets as increasing the risk of the utility. Such a perception could increase the cost of capital to the utility, thereby increasing rates to customers.

BC Gas filed further comments in a letter dated January 12, 2001. BC Gas reiterated its support for a monthly GCRA review based on a pre-defined formula and its view that a three year amortization period for the GCRA is too long. BC Gas also provided information related to the current status of the GCRA including the possibility that the previous estimate of the GCRA balance as at December 31, 2000 ($159 million) may be too low by as much as $20 million.

Consumers' Association of Canada (B.C. Branch) et al.

CAC (BC) et al. indicates that the Commission should direct BC Gas to design a new quarterly gas cost recovery mechanism with further adjustments in the second month of each quarter when required. Rate increases could be triggered if the forecast under-recovery or over-recovery exceeds 5-10 percent of the 12-month forward gas bill. Rates for the upcoming quarter should be based on the forecast average cost of gas over the next 12 months. Amounts in the deferral account should generally be amortized over 12 months, but the very large initial deferral account balance could be amortized over 24 months to reduce rate shock. BC Gas should be required to file monthly reports. The Commission should direct BC Gas to establish a task force including Commission staff, customer representatives and experts to design the new process for implementation January 1, 2001.

BC Health Services Ltd. and R.T. O'Callaghan & Associates Inc.

Minimizing the size of the deferral account is the most important objective of the deferral account and gas cost rate-setting methodology. BC Gas should adopt a monthly rate setting process with amortization of the deferral account balance over a period no longer than one year.

PremStar Pacific

The deferral account and corresponding rate rider should be updated as frequently as possible. The deferral account should be amortized over a period no longer than one year.

Centra Gas British Columbia Inc.

The GCRA balances should be disposed of frequently and systematically. Price transparency, market responsiveness, efficiency of process and volatility of rates are more important than the frequency of rate adjustments. Centra Gas advocates quarterly rate adjustments based on forward strip prices without much in the way of public process.

Appendix B

Excerpt from
COMMERCIAL COMMODITY UNBUNDLING AND CUSTOMER CHOICE PHASE 1 COST ALLOCATION APPLICATION

Terasen Gas

Commodity Unbundling and Customer Choice Phase 1 Cost Allocation Application

Terasen Gas Inc.

January 16, 2004

TABLE OF CONTENTS

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

Description	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6	Rate 7
	Rate Schedule						
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

Description	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6	Rate 7
	Rate Schedule						
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

Description	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6	Rate 7
	Rate Schedule						
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.

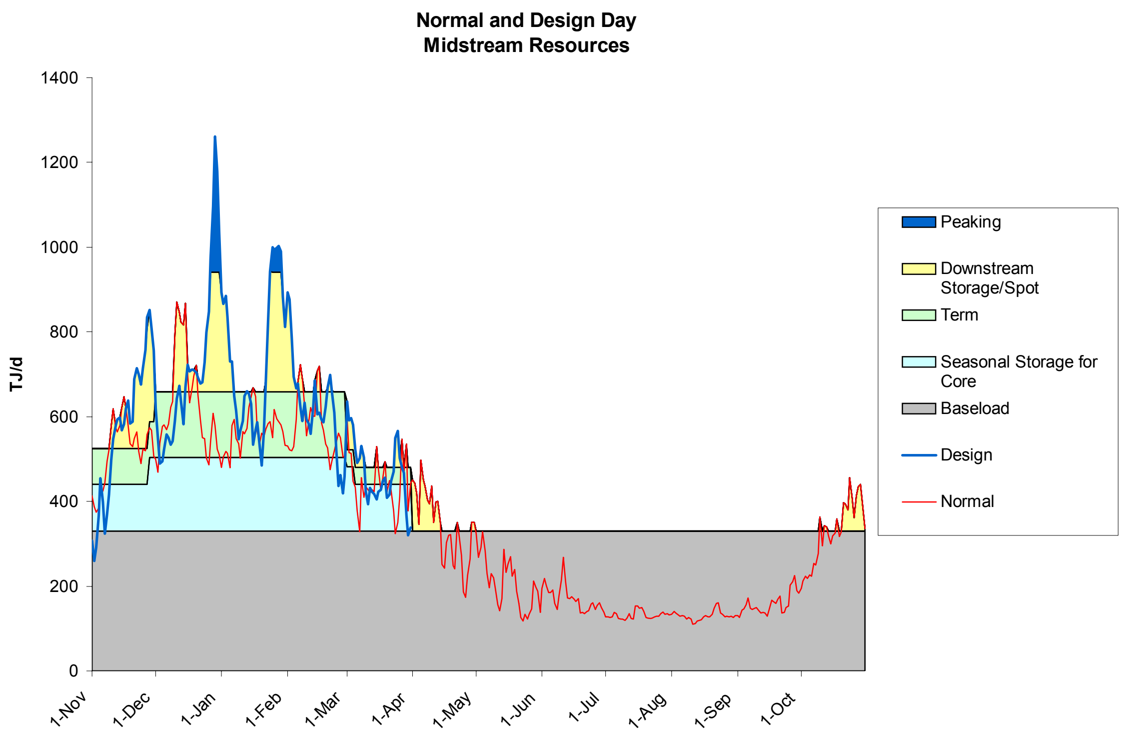
2.3 CCRA and MCRA Reporting and Rate Setting

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

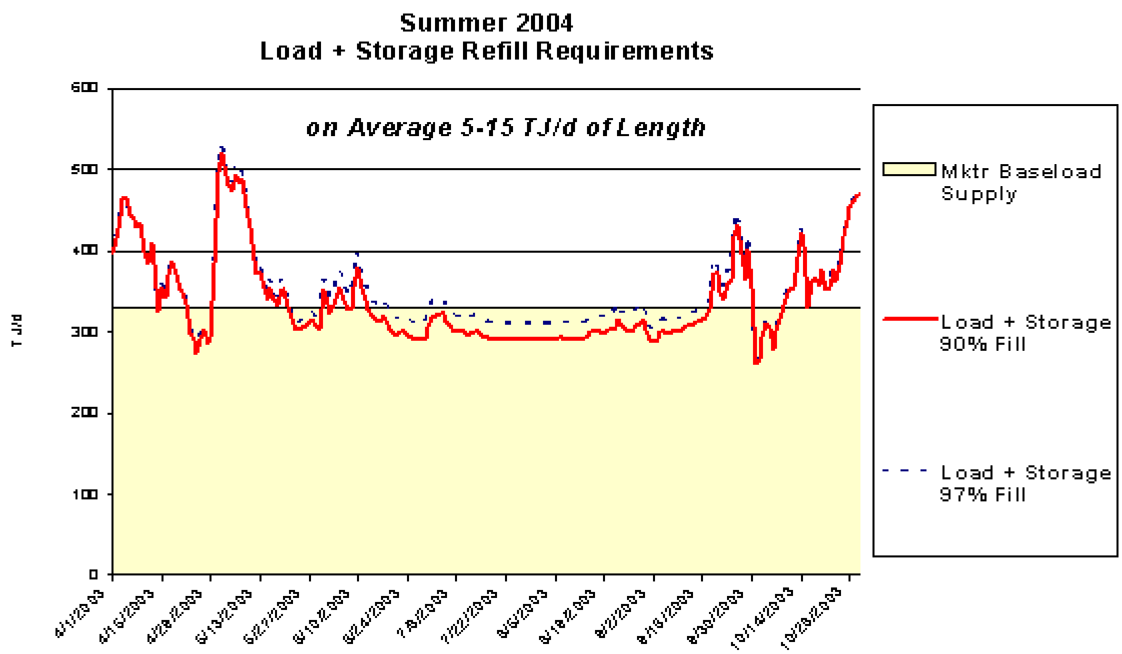
As mentioned under Section 2.2, Terasen Gas requests approval to defer any potential Gas Cost flow-through rate change determined for April 1, 2004 to July 1, 2004, resulting from application of the existing quarterly GCRA review mechanism. This will provide stability to Commercial customers and enhance 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.

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

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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

terasen Gas

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 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	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
FlDec2k4Dec4CCRAr7
04-01-16
16:00

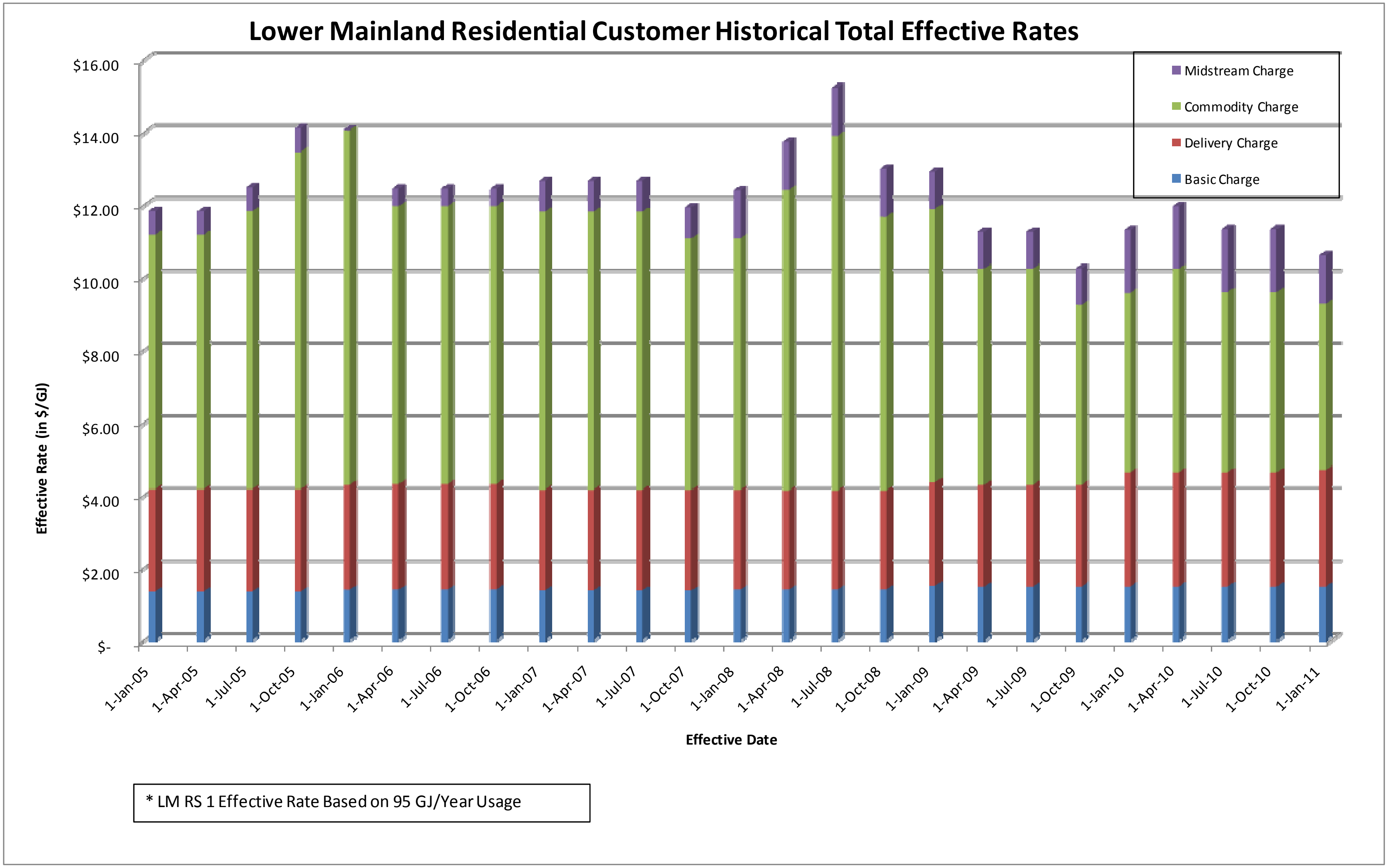
TERASEN GAS INC. - COLUMBIA SERVICE AREA
LOWER MAINLAND/INLAND/COLUMBIA COST OF GAS BY RATE SCHEDULE - CCRA
FORECAST FOR THE 12 MONTHS ENDING DECEMBER 31, 2004
($000)

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														

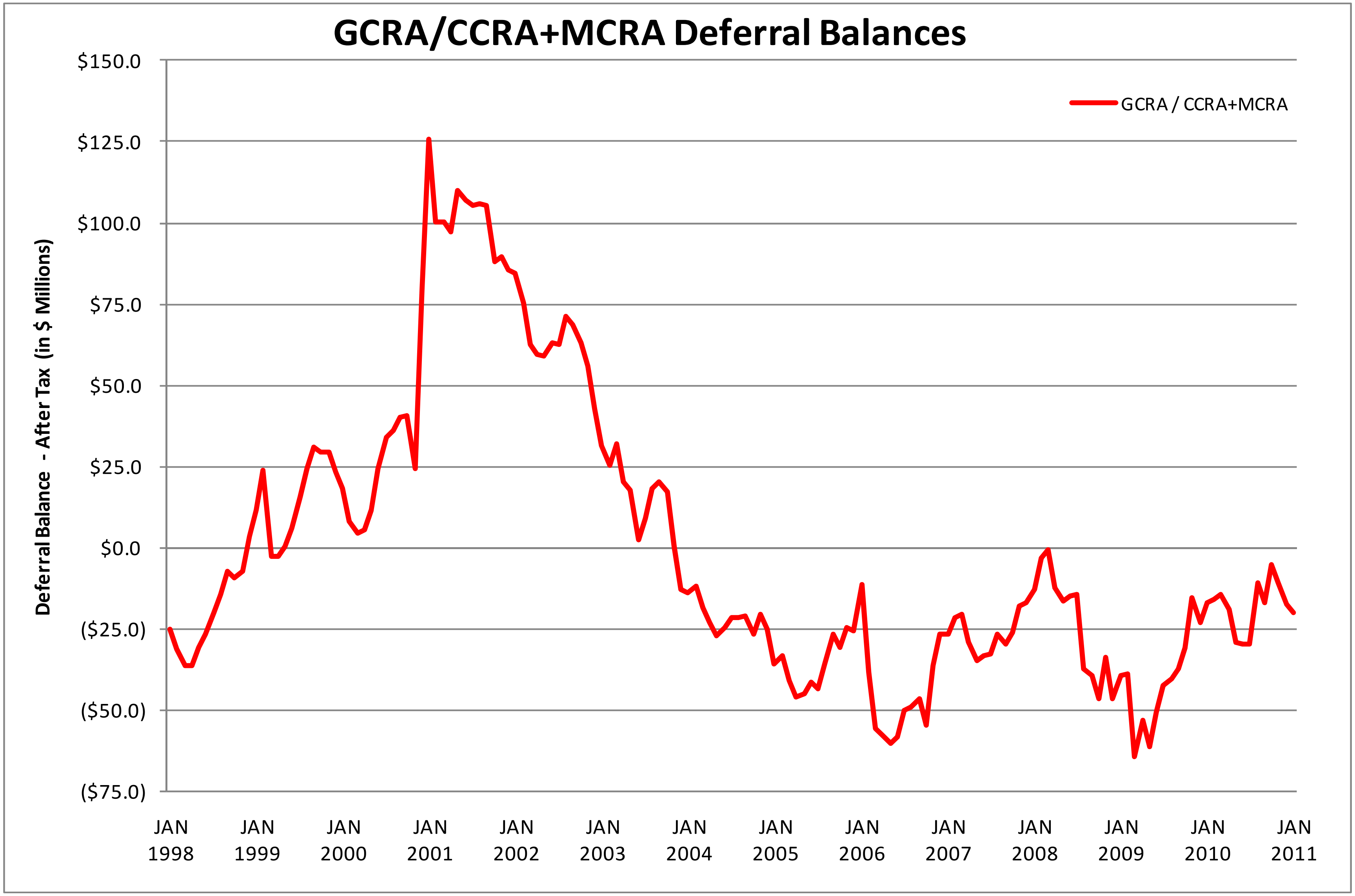
Appendix C

LOWER MAINLAND RESIDENTIAL CUSTOMER HISTORICAL TOTAL EFFECTIVE RATES


Lower Mainland Residential Customer Historical Total Effective Rates
Midstream Charge
Commodity Charge
Delivery Charge
Basic Charge
Effective Rate (in $/GJ)
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
1-Jan-05
1-Apr-05
1-Jul-05
1-Oct-05
1-Jan-06
1-Apr-06
1-Jul-06
1-Oct-06
1-Jan-07
1-Apr-07
1-Jul-07
1-Oct-07
1-Jan-08
1-Apr-08
1-Jul-08
1-Oct-08
1-Jan-09
1-Apr-09
1-Jul-09
1-Oct-09
1-Jan-10
1-Apr-10
1-Jul-10
1-Oct-10
1-Jan-11
Effective Date
* LM RS 1 Effective Rate Based on 95 GJ/Year Usage

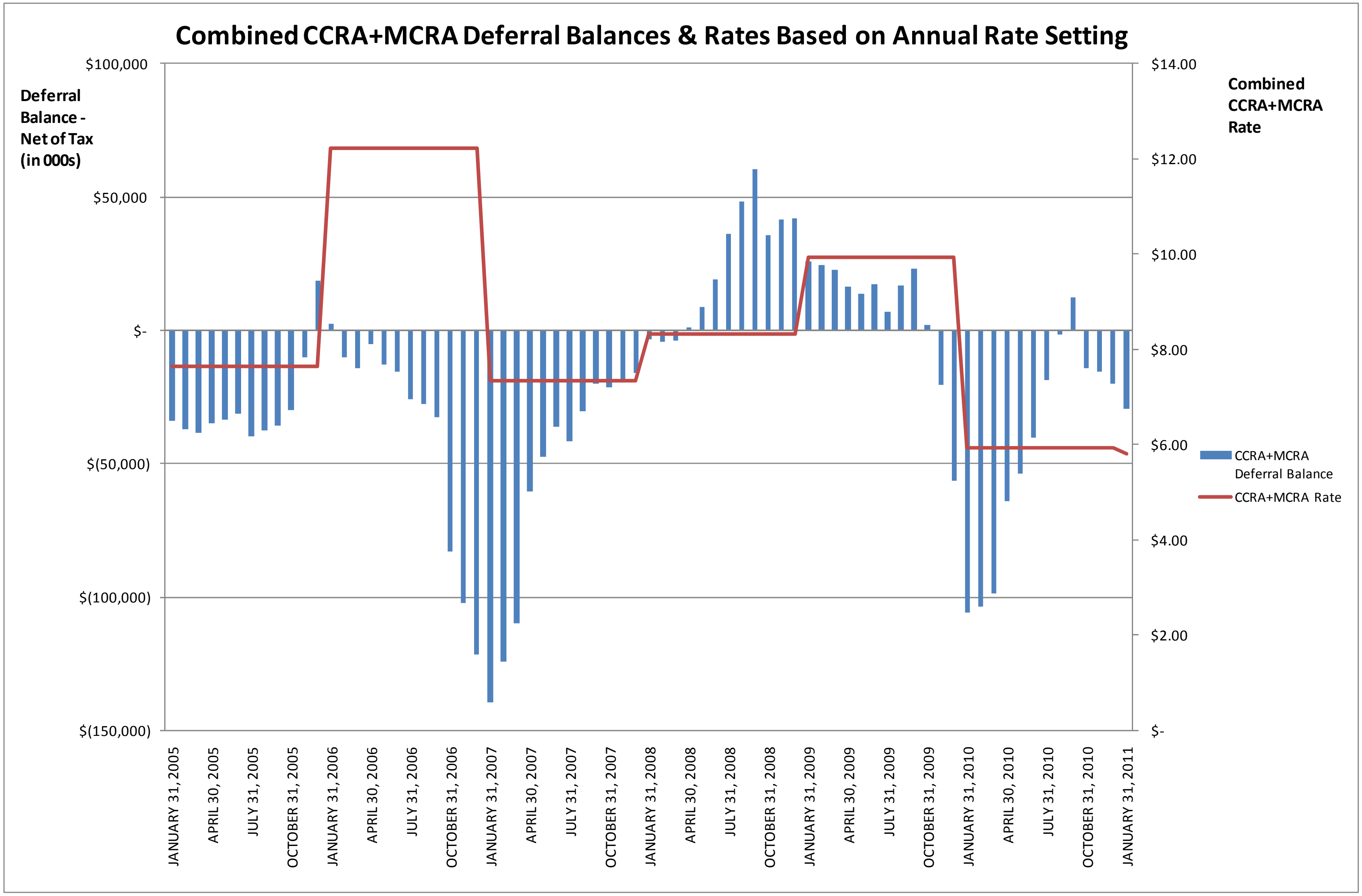
Appendix D

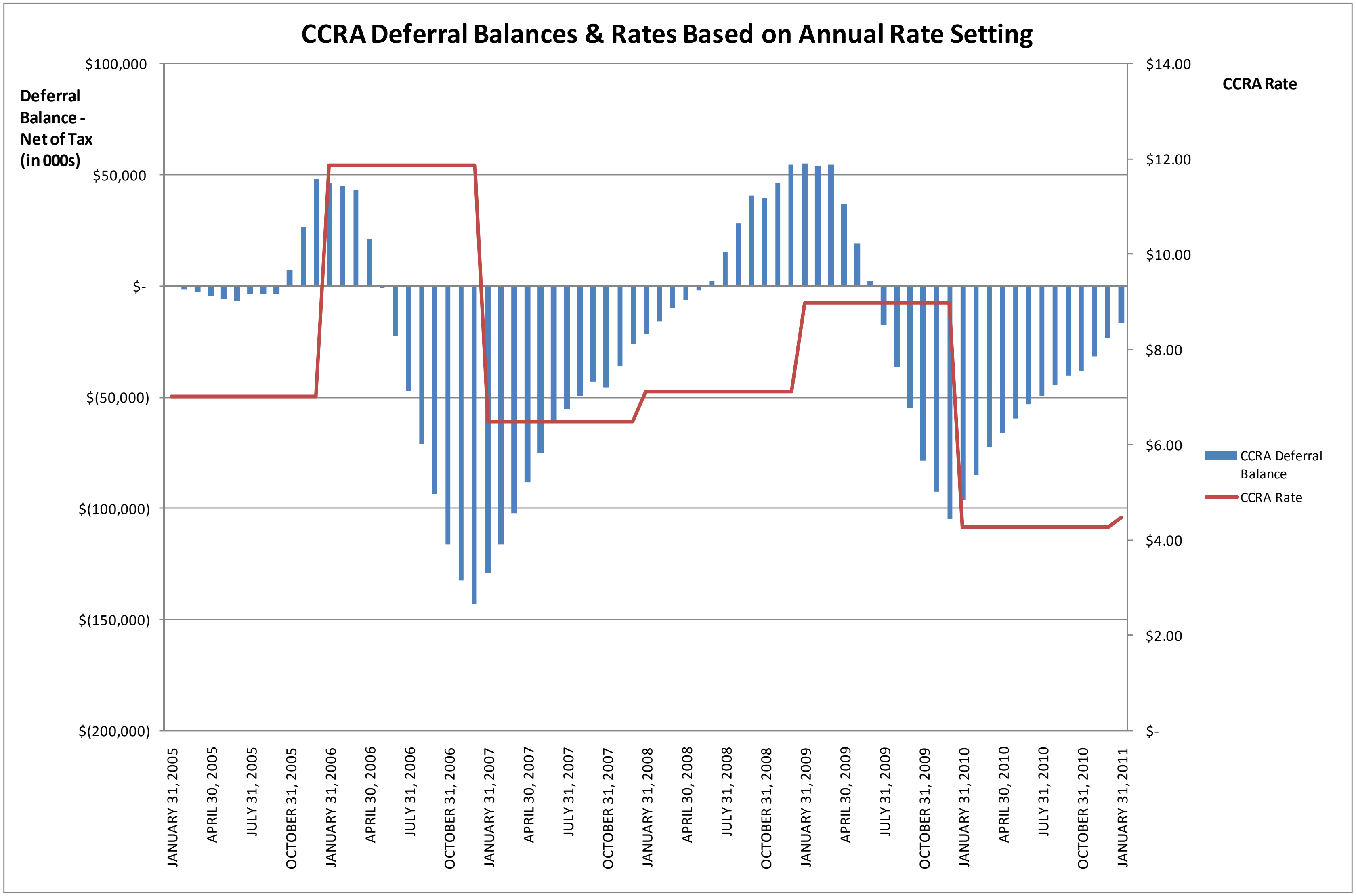
HISTORICAL ACTUAL MONTHLY DEFERRAL ACCOUNT BALANCES


GCRA/CCRA+MCRA Deferral Balances
GCRA / CCRA+MCRA
Deferral Balance - After Tax (in $ Millions)
$150.0
$125.0
$100.0
$75.0
$50.0
$25.0
$0.0
($25.0)
($50.0)
($75.0)
JAN 1998
JAN 1999
JAN 2000
JAN 2001
JAN 2002
JAN 2003
JAN 2004
JAN 2005
JAN 2006
JAN 2007
JAN 2008
JAN 2009
JAN 2010
JAN 2011

Appendix E

DEFERRAL ACCOUNT BALANCES AND RECOVERY RATES BASED ON AN ANNUAL RATE SETTING SCENARIO


Combined CCRA+MCRA Deferral Balances & Rates Based on Annual Rate Setting
Deferral Balance - Net of Tax (in 000s)
$100,000
$50,000
$-
$(50,000)
$(100,000)
$(150,000)
Combined CCRA+MCRA Rate
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
CCRA+MCRA Deferral Balance
CCRA+MCRA Rate
JANUARY 31, 2005
APRIL 30, 2005
JULY 31, 2005
OCTOBER 31, 2005
JANUARY 31, 2006
APRIL 30, 2006
JULY 31, 2006
OCTOBER 31, 2006
JANUARY 31, 2007
APRIL 30, 2007
JULY 31, 2007
OCTOBER 31, 2007
JANUARY 31, 2008
APRIL 30, 2008
JULY 31, 2008
OCTOBER 31, 2008
JANUARY 31, 2009
APRIL 30, 2009
JULY 31, 2009
OCTOBER 31, 2009
JANUARY 31, 2010
APRIL 30, 2010
JULY 31, 2010
OCTOBER 31, 2010
JANUARY 31, 2011


CCRA Deferral Balances & Rates Based on Annual Rate Setting
Deferral Balance - Net of Tax (in 000s)
$100,000
$50,000
$-
$(50,000)
$(100,000)
$(150,000)
$(200,000)
CCRA Rate
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
CCRA Deferral Balance
CCRA Rate
JANUARY 31, 2005
APRIL 30, 2005
JULY 31, 2005
OCTOBER 31, 2005
JANUARY 31, 2006
APRIL 30, 2006
JULY 31, 2006
OCTOBER 31, 2006
JANUARY 31, 2007
APRIL 30, 2007
JULY 31, 2007
OCTOBER 31, 2007
JANUARY 31, 2008
APRIL 30, 2008
JULY 31, 2008
OCTOBER 31, 2008
JANUARY 31, 2009
APRIL 30, 2009
JULY 31, 2009
OCTOBER 31, 2009
JANUARY 31, 2010
APRIL 30, 2010
JULY 31, 2010
OCTOBER 31, 2010
JANUARY 31, 2011

Attachment 11.3

FORTISBC ENERGY INC.
LOWER MAINLAND, INLAND AND COLUMBIA SERVICE AREAS
CCRA HEDGING STUDY SUMMARY
(Balances and Costs are Pre-tax and in Millions)

						CCRA "AS FILED" - includes hedging					"UNHEDGED" CCRA - commodity hedging removed				
Line No.	Quarterly Gas Cost Filing	Rates Effective Date	Forward Prices Date	Forecast Volume Core (TJ)	Forecast Volume CCRA (TJ)	12 Mth Forecast Gas Costs ($ M)	Projected CCRA Opening Balance ($ M)	Forecast CCRA Closing Balance ** ($ M)	Recovery to Cost Ratio (%)	Effective LM RS 1 CCRA Rate ($/GJ)	12 Mth Forecast Gas Costs ($ M)	Projected CCRA Opening Balance ($ M)	Forecast CCRA Closing Balance ** ($ M)	Recovery to Cost Ratio (%)	Effective LM RS 1 CCRA Rate ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	2004 Q1 *	May 1, 2004	Apr 19, 2004							$ 6.518					$ 6.518
2	2004 Q2	Jul 1, 2004	Jun 7, 2004	120,723	120,723	$ 846	$ 2	$ 61	92.9%	7.005	$ 876	$ 8	$ 98	89.0%	7.266
3	2004 Q3	Oct 1, 2004	Aug 31, 2004	120,811	120,811	805	(21)	(21)	103.1%	7.005	825	(29)	(35)	104.5%	7.266
4	2004 Q4	Jan 1, 2005	Nov 19, 2004	119,005	119,005	834	6	1	99.9%	7.005	860	4	(1)	100.2%	7.266
5	2005 Q1	Apr 1, 2005	Feb 22, 2005	120,163	111,956	782	(5)	(6)	100.6%	7.005	793	(6)	(25)	103.2%	7.266
6	2005 Q2	Jul 1, 2005	Jun 2, 2005	120,449	110,852	851	(4)	72	91.5%	7.658	878	(37)	37	95.6%	7.604
7	2005 Q3	Oct 1, 2005	Aug 31, 2005	120,606	110,677	1,048	(19)	182	82.4%	9.292	1,155	3	316	72.7%	10.458
8	2005 Q4	Jan 1, 2006	Nov 22, 2005	116,232	106,507	1,039	-	52	95.0%	9.774	1,124	(13)	(1)	100.1%	10.458
9	2006 Q1	Apr 1, 2006	Mar 7, 2006	116,061	107,570	857	(35)	(227)	127.6%	7.662	801	(88)	(410)	157.5%	6.641
10	2006 Q2	Jul 1, 2006	May 26, 2006	115,976	106,891	857	(58)	3	99.6%	7.662	786	(67)	29	96.0%	6.641
11	2006 Q3	Oct 1, 2006	Aug 21, 2006	115,911	107,399	908	(83)	1	99.8%	7.662	864	(61)	89	88.9%	6.641
12	2006 Q4	Jan 1, 2007	Nov 21, 2006	116,540	107,324	908	(76)	11	98.6%	7.662	848	(20)	117	85.8%	6.641
13	2007 Q1	Apr 1, 2007	Feb 28, 2007	116,530	104,666	889	(52)	36	95.7%	7.662	843	15	164	80.9%	6.641
14	2007 Q2	Jul 1, 2007	Jun 1, 2007	116,487	100,796	828	(55)	2	99.8%	7.662	776	78	186	78.2%	6.641
15	2007 Q3	Oct 1, 2007	Aug 28, 2007	116,575	97,374	726	(85)	(96)	115.0%	6.926	634	66	54	91.1%	7.284
16	2007 Q4	Jan 1, 2008	Nov 26, 2007	115,021	95,876	727	(56)	7	99.0%	6.926	656	(77)	(119)	120.5%	7.284
17	2008 Q1	Apr 1, 2008	Feb 27, 2008	115,265	94,712	805	(22)	130	83.5%	8.287	788	(29)	72	90.5%	8.045
18	2008 Q2	Jul 1, 2008	May 28, 2008	115,355	94,363	923	-	141	84.7%	9.780	988	1	230	76.7%	10.485
19	2008 Q3	Oct 1, 2008	Sep 5, 2008	115,405	94,678	760	(46)	(211)	129.8%	7.536	729	(54)	(318)	147.1%	7.127
20	2008 Q4	Jan 1, 2009	Nov 24, 2008	108,739	85,939	693	(33)	13	98.1%	7.536	670	(64)	(7)	101.1%	7.127
21	2009 Q1	Apr 1, 2009	Feb 24, 2009	108,179	85,872	547	(36)	(132)	126.4%	5.962	454	(53)	(206)	152.5%	4.675
22	2009 Q2	Jul 1, 2009	Jun 1, 2009	108,017	85,601	532	(57)	(34)	107.5%	5.962	428	(51)	(21)	106.0%	4.675
23	2009 Q3	Oct 1, 2009	Aug 24, 2009	112,982	90,871	543	(96)	(89)	120.4%	4.953	423	(99)	(95)	130.1%	3.592
24	2009 Q4	Jan 1, 2010	Dec 2, 2010	112,952	92,347	546	(64)	24	95.2%	4.953	442	(47)	61	84.7%	3.592
25	2010 Q1	Apr 1, 2010	Feb 23, 2010	114,414	94,939	556	(23)	61	88.4%	5.609	477	(8)	124	73.1%	4.932
26	2010 Q2	Jul 1, 2010	May 25, 2010	114,279	95,137	516	(42)	(60)	112.7%	4.976	422	(22)	(67)	117.2%	4.204
27	2010 Q3	Oct 1, 2010	Aug 24, 2010	114,439	96,199	484	(38)	(32)	107.3%	4.976	375	(45)	(53)	122.3%	4.204
28	2010 Q4	Jan 1, 2011	Nov 23, 2010	114,410	96,253	463	(20)	(41)	109.1%	4.568	374	(31)	(45)	118.0%	3.566
29	2011 Q1	Apr 1, 2011	Feb 22, 2011	114,578	97,968	421	(6)	(32)	107.7%	4.568	346	(12)	(15)	104.7%	3.566

* Pursuant to Commission Order No. G-25-04, the 2004 Q1 gas cost report was deferred to an April filing with the expectation that any significant difference in costs should be flowed through rates effective May 1, 2004.

** Forecast CCRA closing balance at existing rates (note, when recovery rates are reset, the forecast closing balance will be zero).