BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-120-11

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
(collectively Terasen Gas) (now FortisBC Energy Inc. and FortisBC Energy (Vancouver) Inc.)
for Approval of the Price Risk Management Plan Effective April 2011–October 2014

BEFORE: D.A. Cote, Panel Chair/ Commissioner
L.A. O'Hara, Commissioner
N.E. MacMurchy, Commissioner

July 12, 2011

O R D E R

WHEREAS:

A. On July 22, 2010, the British Columbia Utilities Commission (Commission), by Orders E-23-10 and E-24-10, denied the 2010 Price Risk Management Plans submitted by FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) respectively. In letters which accompanied the Orders, the Commission directed FEI and FEVI, in consultation with Commission staff, to conduct a review of the PRMP's primary objectives in the context of the *Clean Energy Act* and increased domestic natural gas supply;

B. On January 27, 2011, FEI filed with the Commission on a confidential basis the "Review of the Price Risk Management Objectives and Hedging Strategy" providing the results of the FEI review of the of the PRMP objectives and the recommendations of its consultant, RiskCentrix, LLC for an enhanced hedging strategy;

C. On January 27, 2011, FEI also filed with the Commission on a confidential basis the "Price Risk Management Plan Effective April 2011–October 2014" (2011 PRMP or Filing) for approval of the objectives and key elements of the 2011 PRMP which include measures for programmatic, defensive, and value hedging as well as basis swaps to hedge price exposure at the Sumas trading hub;

D. The Commission reviewed the Filing and concluded that prior to making a determination on the need for a hedging program, a written process was necessary to review the objectives of the 2011 PRMP;

E. On February 18, 2011, FEI filed redacted copies of the 2011 PRMP and Review of the Price Risk Management Objectives and Hedging Strategy suitable for public review;

F. On February 22, 2011, the Commission issued Order G-23-11 establishing a Written Public Hearing process (the Proceeding) with a Regulatory Timetable to review the objectives of the 2011 PRMP;

G. Order G-23-11 approved FEI at its discretion over the course of the proceeding to, on an interim basis, implement those measures related to value hedging, programmatic hedging and Sumas basis swaps as outlined in the 2011 PRMP;

H. Effective March 1, 2011 Terasen Inc. changed its corporate name to FortisBC Holdings Inc. such that Terasen Gas Inc. became FortisBC Energy Inc. (FEI) and Terasen Gas (Vancouver Island) Inc. became FortisBC Energy (Vancouver Island) Inc.;

I. The Commission has considered the Filing, submissions and evidence provided by FEI/FEVI.

NOW THEREFORE the Commission, for the Reasons attached as Appendix A orders as follows:

1. With the exception of the Sumas/AECO Basis Swaps element the FEI 2011-2014 PRMP Filing is denied.

2. FEI is encouraged to consider alternate means of augmenting the existing non-PRMP tools used to manage natural gas price volatility as discussed in the attached Reasons for Decision.

3. FEI is directed to properly manage its existing PRMP portfolio positions in a prudent manner to expiry, unless otherwise directed by the Commission.

DATED at the City of Vancouver, in the Province of British Columbia, this *12th* day of July 2011.

BY ORDER

Original signed by:

D.A. Cote
Commissioner

Attachment

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

FORTISBC ENERGY INC. AND
FORTISBC ENERGY (VANCOUVER ISLAND) INC.
2011-2014 PRICE RISK MANAGEMENT PLAN

REASONS FOR DECISION

July 12, 2011

BEFORE:

D.A. Cote, Panel Chair / Commissioner
L.A. O'Hara, Commissioner
N.E. MacMurchy, Commissioner

TABLE OF CONTENTS

Page No.

APPENDICES

1.0 INTRODUCTION

1.1 The Filing

Both FortisBC Energy Inc. (FEI), formerly known as Terasen Gas Inc. and FortisBC Energy (Vancouver Island) Inc. (FEVI), formerly known as Terasen Gas (Vancouver Island) Inc. (collectively the Utilities or FEU) as is the traditional practice, file separate annual Price Risk Management Plans (PRMP) seeking approval of gas commodity hedging plans for the next three year period and, in the case of FEVI, for the next five years. In May of 2010 both FEI and FEVI submitted their PRMPs for review and acceptance by the British Columbia Utilities Commission (BCUC, Commission). On July 22, 2010 BCUC issued Order E-23-10 and Order E-24-10 which denied the PRMP Applications of FEI and FEVI. In addition, these Orders directed the Utilities to conduct a review of the primary objectives of the PRMP in the context of the *Clean Energy Act (CEA)* and the increase in domestic natural gas supply. Further, on the basis of discussions held with Commission staff FEU also agreed to expand this review by examining the cost/benefit value of hedging for customers. (Exhibit B-1, p. 4)

On January 27, 2011 FEU filed with the Commission on a confidential basis the “Review of Price Risk Management Objectives and Hedging Strategy” (Review Report) which included the results of its review of the PRMP objectives and an enhanced hedging strategy based on the recommendations of its consultant, RiskCentrix, LLC. In addition, FEI filed with the Commission on a confidential basis the “Price Risk Management Plan Effective April, 2011 to October, 2014.” This included the program objectives and the key elements of the 2011 PRMP which includes Programmatic, Defensive and Value hedging measures as well as a program of Basis Swaps designed to hedge price exposure at the Sumas trading hub. These filings collectively constitute the FEU response to the Commission Directives in Orders E-23-10 and E-24-10 respectively. On February 18, 2011, FEU filed redacted copies of both of these documents which were suitable for public review. On February 27, 2011, the Commission issued Order G-23-11 which concluded that prior to making a determination on the need for a hedging program, a review of the 2011 PRMP Objectives was required and established a regulatory process. In these Reasons for Decision, the Commission Panel will examine the evidentiary record and provide a determination on the validity of the PRMP Objectives and whether there is a need for a formal hedging program. For clarity purposes, the Commission Panel acknowledges its understanding that the Review Report applies to both Utilities while the PRMP applies to FEI only as stated in the cover letter.

1.2 The Applicant

FEI and FEVI are companies incorporated under the laws of the Province of British Columbia and are wholly owned subsidiaries of Fortis Inc. On March 1, 2011 the Terasen group of companies began operating under the FortisBC Energy Inc. brand name but continue to operate as separate legal entities. Fortis BC Energy and its affiliated companies sell and deliver natural gas to residential, commercial and industrial companies throughout British Columbia. They provide service to over 940,000 customers in 125 communities encompassing 95 percent of natural gas users within the province.

1.3 Key Stakeholders

The key stakeholders of the FortisBC Utilities Price Risk Management Program and related hedging strategies are its ratepayers who purchase gas. FEU states that the program has three primary objectives related to: maintaining competitiveness with other energy sources, reducing price volatility and reducing the risk of regional price disconnects. The position of the Utilities is that the achievement of these objectives is in the best interests of customers. (FEU Final Submissions, p. 5) Accordingly, the Commission Panel has the expectation that the benefits derived in satisfying these objectives must be sufficient to justify them in relation to additional ratepayer costs.

1.4 Orders Sought

As outlined in its Final Submissions FEU is seeking the following:

- The Commission’s endorsement of the price risk management primary objectives which have been reviewed in light of developments including the introduction of the *Clean Energy Act* and increased domestic gas supply; and

- Approval of the FEI 2011-2014 Price Risk Management Plan dated January 27, 2011, which includes the implementation strategy and hedging instruments necessary to meet the objectives.

1.5 Regulatory Process

The review of the Filing was conducted by way of a written proceeding. The Interveners in this proceeding were the British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO) and the Commercial Energy Consumers Association of British Columbia (CEC). Both of these Intervener groups participated very actively in the processes. The Regulatory Timetable which included two rounds of Information Requests (IRs), Final Submissions from the participants and Reply Submissions from the Applicant is summarized in Appendix 1.

2.0 COMMISSION PANEL DECISION SUMMARY

The Commission Panel has reached the following conclusions regarding the FEI 2011-2014 Price Risk Management Plan and its objectives:

1. Endorsement of the FEU PRMP Primary Objectives

    - **The need for an objective related to the competitiveness of natural gas with other energy sources has not been established.**

    - **Moderation of the volatility of natural gas prices to stabilize customer rates is a reasonable goal for the Utilities to pursue. However, the Panel rejects the notion that it necessarily follows the proposed PRMP is the most cost-effective approach or solution.**

2. Approval of the FEI 2011-2014 PRMP

    - **With the exception of those elements related to the usage of Sumas-AECO Basis Swaps, we reject the FEI 2011-2014 PRMP dated January 27, 2011.**

3.0 BACKGROUND

3.1 Natural Gas Overview

FEU provided evidence that the natural gas market in North America has undergone significant changes in the last few years. There has been a dramatic increase in supply, largely from unconventional supply sources (coal bed methane, tight gas and shale gas). Supply increases have also been driven by advances in horizontal drilling technology that have reduced production costs. At the same time, demand for natural gas has been reduced in direct response to the downturn in the global economy. The bulk of this reduction is attributed to a drop in demand from industrial customers. The result has been record high gas storage levels and depressed natural gas prices.

FEU foresees that natural gas prices in the future could be quite different than today, as gas supply activity diminishes in response to low gas prices and industrial demand increases with economic recovery. These broad supply and demand factors are seen as longer term affecting natural gas prices over periods of years rather than months. (Exhibit B-1, pp. 16-21)

In the short term, FEU sees natural gas prices as potentially being affected by a number of factors including:

- Supply disruptions such as pipeline constraints during peak demand periods;
- Weather related supply disruptions such as hurricanes that disrupt production during the active hurricane season in the summer months;
- Unusually hot summer temperatures increase demand for natural gas for air conditioning loads;
- High demand for space heating in the winter months; and
- Relative prices of competing fuels, such as crude oil or coal. (Exhibit B-1, p.22)

In assessing the future impact of these supply/demand factors, FEU concludes that there is no information to suggest with any certainty that future market price volatility or market price spikes will be any greater or any less than in the past. (Exhibit B-5, CEC 1.13.2)

3.2 FEU Hedging Performance

3.2.1 Historical Impact of FEU Hedging on Price Volatility and Competitiveness with Electricity

FEU sets out a graph demonstrating that the FEU hedged commodity rate is less volatile than the AECO market (Exhibit B-4, BCOAPO 1.2.2). It also shows that the FEU hedged rate has generally tracked above the AECO market price, has been moderately higher than the "Electric Equivalent 60 percent Efficiency bench mark, and significantly lower than the "Electric Equivalent 90 percent Efficiency bench mark." FEU sees the Electric Efficiency bench mark as being significant for assessing the competitiveness of natural gas in applications such as water heating where natural gas water heaters are only 60 per cent efficient relative to electric water heaters, while the 90 per cent bench mark is significant with respect to natural gas's competitiveness with electricity for space heating purposes. (Exhibit B-1, p. 51-55)

3.2.2 Cost of FEU Hedging Programs

FEU presented information on the hedging losses for both FEI and FEVI. The results are summarized below in Tables 1 and 2.

TABLE 1

FortisBC Energy Inc.			
Year	**Total Annual Hedging Gains/(Costs) ($ millions) (A)**	**Total Commodity Purchased ($ millions) (B)**	**Gain/(Cost) as a percentage of Total Commodity Purchased (A/B)**
2000	$26.4	$574.5	4.60%
2001	$(56.3)	$763.7	(7.37%)
2002	$(123.9)	$626.9	(19.77%)
2003	$8.6	$721.8	1.19%
2004	$15.6	$675.8	2.3%
2005	$66.2	$773.5	8.56%
2006	$(88.1)	$758.0	(11.62%)
2007	$(136.8)	$804.5	(17.01%)
2008	$(40.9)	$825.7	(4.96)
2009	$(163.1)	$620.1	(26.29%)
2010	$(133.8)	$491.5	(27.23%)

- Total Commodity Purchased is based on the annual commodity costs including hedging gains/costs, net storage activity and commodity resale.
- Total Commodity Purchased includes Lower Mainland, Inland, and Columbia service areas.
- Figures are provided on a calendar year basis.

TABLE 2

Fortis BC Energy (Vancouver Island) Inc			
Year	**Total Annual Hedging Gains/(Costs) ($millions) (A)**	**Total Commodity Purchased ($millions) (B)**	**Gain/(Cost) as a percentage of Total Commodity Purchased (A/B)**
2000	n/a	$44.2	n/a
2001	n/a	$66.6	n/a
2002	$0.3	$49.2	0.57%
2003	$4.3	$70.9	6.09%
2004	$2.6	$71.9	3.66%
2004	$5.2	$94.3	5.49%
2006	$(5.0)	$93.0	(5.35%)
2007	$(6.3)	$92.3	(6.87%)
2008	$(1.8)	$103.1	(1.70%)
2009	$(19.7)	$82.0	(24.04%)
2010	$(15.1)	$67.9	(22.22%)

- Hedging activity for FEVI began in 2002.
- Total Commodity Purchased is based on the annual commodity costs including hedging gains/losses, net storage activity, and peaking gas resale.
- Figures are provided on a calendar year basis.

(Exhibit B-3, BCUC 1.1.1)

For the last five years FEI, on average, had hedging losses of $112.5 million per year and FEVI losses of $9.6 million. Losses for both utilities were most significant in the 2009-2010 periods which coincided with a sharp drop in natural gas commodity prices.

Reviewing each area of hedging activity based on the hedging cost and volume data supplied by FEU shows that FEU has effectively used Basis Swaps to lock in the AECO/Sumas basis spread to the benefit of its customers. The average cost of basis spreads for the period 2006 to 2010 was only $0.06/GJ. This is significantly less than the costs of other hedging instruments over this period which were $2.24/GJ for financial fixed instruments, $1.38/GJ for costless collars and $1.34/GJ for calls. The costs of each of these instruments are illustrated below:

TABLE 3

Average Gains (Costs)/GJ of Hedging Instruments for the Period 2006 to 2010

Year	Financial Fixed			Costless Collars		
	Gains/Costs (A)	Hedged Volume (GJ) (B)	Average cost/GJ (A/B)	Gains/Costs (A)	Hedged Volume (GJ) (B)	Average cost/GJ (A/B)
2006	($75,059,847)	47,721,411	($1.57)	($24,952)	5,194,800	($0.005)
2007	($117,924,893)	49,813,300	($2.37)	($1,670,273)	2,310,750	($0.72)
2008	($22,607,026)	36,188,974	($0.62)	($955,268)	2,926,850	($0.33)
2009	($134,061,221)	38,326,914	($3.50)	(20,417,898)	7,936,637	($2.57)
2010	($124,842,095)	39,722,870	($3.14)	($10,524,415)	5,938,974	($1.77)
Total 2006-2010	**($474,495,082)**	**211,773,469**	**($2.24)**	**($33,592,806)**	**24,308,011**	**($1.38)**

Year	Basis Swaps			Calls		
	Gains/Costs (A)	Hedged Volume (GJ) (B)	Average cost/GJ (A/B)	Gains/Costs (A)	Hedged Volume (GJ) (B)	Average cost/GJ (A/B)
2006	$651,378	5,997,119	$0.11	($13,043,081)	11,104,300	($1.75)
2007	$1,608,145	8,032,774	$0.20	($20,023,329)	13,746,700	($1.46)
2008	($1,477,226)	7,780,700	($0.19)	($16,838,363)	13,165,500	($1.28)
2009	($2,664,092)	4,751,033	($0.56)	($7,710,476)	5,033,699	($1.53)
2010	($367,972)	13,412,949	($0.03)	($541,549)	388,514	($1.39)
Total 2006-2010	**($2,249,767)**	**39,974,575**	**($0.06)**	**($58,156,798)**	**43,438,713**	**($1.34)**

(Source: Exhibit B-4, BCOAPO 1.2.5)

3.3 Hedging Practices in Other Jurisdictions

FEU provides information on the use of hedging by gas utilities in other jurisdictions, including the nature and limitations of such use. Table 4 summarizes hedging activities in other jurisdictions.

TABLE 4

Hedging Activity in Other Jurisdictions			
Province	**Hedging Use**	**Max %of Options Approved for Use**	**Reference**
Alberta	Not Used	n/a	Exhibit B-5 p.37
Saskatchewan	In Use	70% summer and 90% winter subject to $15M in call option premiums (unlimited use of costless collars)	Exhibit B-3, p.48
Manitoba	Not used	n/a	Exhibit B-1, p.29
Ontario	Not used	n/a	Exhibit B-1, p.30
Quebec	In use	30% summer and 50% winter	Exhibit B-3, p.48

3.3.1 Provinces Allowing Hedging

Saskatchewan

SaskEnergy Incorporated (SaskEnergy) has an active hedging program that in FEU's view has enabled SaskEnergy to reduce market price volatility. It has allowed SaskEnergy to limit commodity rate changes to only twice a year for the past few years despite the price volatility in the marketplace. (Exhibit B-1, p. 29)

Based on conversations with SaskEnergy, FEU determined that:

- its hedging horizon is three to four years;
- it hedges a significant portion of its portfolio with a mix of instruments;
- it has the flexibility to choose the mix of hedging instruments it utilizes and generally prefers to use fixed price swaps in low price environments and more options in high price environments; and
- it is limited in terms of total budgeted costs for call options as set out in the Table 4 above.

FEU notes that the hedging approach including the use of the mix of hedging instruments is consistent with the FEU proposed enhanced hedging strategy. (Exhibit B-3, BCUC 1.9.1.2)

Quebec

Gaz Metro Limited Partnership (Gaz Metro) uses hedges to mitigate market price risk. FEU notes that, like the Utilities, Gaz Metro faces the challenge of competing with electricity. Because of Quebec's abundant hydro-electric generating capacity, electricity rates in the province are amongst the lowest in the country. FEU states that the hedging program of Gaz Metro helps in this regard. (Exhibit B-1, p. 30)

Based on conversations with Gaz Metro, FEU determined that Gaz Metro's approach to hedging is the same as SaskEnergy. Unlike SaskEnergy, Gaz Metro does not have any cost limitations in its use of options. (Exhibit B-3, BCUC 1.9.1.2)

Manitoba

Manitoba Hydro does not have a formal hedging program. For its default service offerings, it is allowed to offer fixed rate programs to its customers and does engage in hedging activity to support those offerings. As the utility is able to offer fixed rate services, Manitoba Hydro has been directed to wind down its hedging program related to the quarterly standard variable rate offerings by July 2011 and to cease any hedging for periods beyond this month. (Exhibit B-3, BCUC 1.9.1.2)

3.3.2 Provinces Not Allowing Hedging

Alberta

FEU notes that until this past winter, the government of Alberta provided natural gas customers with a rebate if natural gas prices exceeded $5.50/GJ. This effectively insulated consumers from price volatility whenever gas rates exceeded this threshold. However due to the impact of the recent recession on Alberta government revenues this program was discontinued. Currently with the absence of a rebate program and with no hedging programs by Alberta utilities, customers are fully exposed to market prices. Natural gas rates in Alberta are adjusted monthly. (Exhibit B-5, CEC 1.23.1)

Ontario

The primary natural gas utilities in Ontario, Union Gas Limited (Union Gas) and Enbridge Gas Distribution Inc. (Enbridge), had hedging programs in the past but do not currently. Their hedging programs were cancelled by the regulator, the Ontario Energy Board (OEB) in 2007 and 2008. While these utilities maintained that their risk management activities had provided a material reduction in rate volatility, the OEB disagreed and found that the quarterly rate adjustment and the equal billing plan provided sufficient rate smoothing effects. FEU strongly disagrees with this conclusion. (Exhibit B-1, p. 30)

FEU also points out that a major difference in circumstances between the Ontario utilities and the Utilities is that the Ontario utilities have significant amounts of contracted storage capacity (166 PJ). The Ontario utilities' access to the liquid Dawn market hub reduces their need to purchase seasonal and peaking gas and allows them to take advantage of favourably priced spot gas when load requirements dictate. In contrast FEU states that storage capacity in the Pacific Northwest is relatively scarce and FEU does not have the same access to storage resources as Ontario utilities. This is seen as having adverse price impacts in the Pacific Northwest region, particularly at Station 2 and Sumas during periods of high demand, typically seen during cold winter months. (Exhibit B-5, CEC 1.23.1)

To enhance storage and provide peaking services a number of activities have been undertaken by FEU. FEVI is currently completing the construction of the Mt. Hayes LNG storage facility on Vancouver Island, which will add 1.5 billion cubic fee (Bcf) of storage capacity to the area and provide peaking services to both FEVI and FEI beginning in 2011. In 2006, FEI contracted for a long-term capacity addition at Jackson Prairie in the Pacific Northwest, which helped to underpin the ongoing expansion of that facility. FEI also holds the largest amount of storage capacity at Mist, other than that held by Northwest Natural for its own customers. FEI in the past has investigated the potential for greenfield underground storage projects in the region, however, it has concluded that no cost effective opportunities are available outside of limited potential for further expansions at Mist or Jackson Prairie. (Exhibit B-8, CEC 2.6.1)

3.3.3 Comparative Assessment of Results in Other Jurisdictions

FEU has not undertaken a comparative quantitative performance analysis for utilities in other jurisdictions and is not privy to performance details where hedging is done. As pointed out by FEU, each utility faces unique operating and market environments and competitive challenges. This limits the usefulness of the assessment of the use (or non-use) of hedging activity in other jurisdictions as a determinant of the merits of FEU proceeding with its proposed program. (Exhibit B-5, CEC 1.23.2)

4.0 PRICE RISK MANAGEMENT - PROPOSED PROGRAM

4.1 Price Risk Management Plan Objectives

FEU states that the primary objectives of the PRMP can be described as follows:

(i) improve the likelihood that natural gas will continue to be competitive with other energy sources;

(ii) moderation of gas price volatility and its effect on customer rates; and

(iii) reduction of risk due to regional price disconnects.

FEU further states that the PRMP has a further underlying objective of providing this volatility protection and competitiveness at a reasonable cost to its customer base. The Commission Panel considers these objectives as a basis for the justification of having a Price Risk Management Plan. Accordingly, we believe that any decision to move forward with a PRMP will be a consequence of the determinations made on the validity of these objectives and whether the benefits derived from achieving them justify the costs to ratepayers. (Exhibit B-1, p. 31) In what follows we will review submissions with regard to each of these.

4.1.1 Competitiveness with Other Energy Sources

FEU submits that the maintenance of competitiveness with other energy sources allows it to grow its customer base and provide continued reasonable rates. The Utilities state that while the primary competitive challenge currently is electricity this objective will become increasingly important in the future as more options for energy sources such as air or ground source heat pumps become popular. Further, it states that the maintenance of competitiveness is not only good for FEU customers but is also in the best interests of those who consume electricity.

FEU's view is that if natural gas rates are considered to be uncompetitive with electricity, the consequence will be upward pressure on both natural gas and electricity delivery rates. This is based on the expectation that customer and load migration from natural gas to electricity will occur. FEU submits that this in turn results in the need for electricity distribution upgrades and the requirement for incremental power sources. The cost of these is considerably higher than what it describes as the embedded cost of supply which is dominated by Heritage generation resources with an embedded average residential rate of $0.065/kWh. It estimates these new electricity sources to be in the $0.12/kWh or higher range. Correspondingly, FEU states that delivery rates for its customers would increase reflecting the decrease of system throughput and the fact that much of the utility cost of service is fixed. To illustrate this point FEU cites the example of its competitive challenge with hot water heating where natural gas has a typically lower efficiency level than electricity (60 percent as opposed to 90 percent for electricity hot water heaters) and where customers incur the lower step 1 electricity rate. FEU notes that if FEI were to lose its entire current residential and commercial water heating load (presumably because of an electricity cost advantage), the result would be a 22 PJ decline and delivery rates could increase between 12 and 17 percent. Moreover, FEU estimates that if this migration were to occur it would result in an electricity rate increase in the 5 percent range. (Exhibit B-1, pp. 31-34)

FEU's view is that electricity rates have historically been based on utility-owned supply and infrastructure costs and not on market-based prices. Also they have not been affected by market price volatility and significant increases. However, FEU note that given the current situation, BC Hydro faces an era where costs and rates will increase as the company moves to achieve self-sufficiency and cleaner energy. While it is acknowledged that this could improve the Utility's ability to manage electricity competitiveness, numerous supply and demand factors affecting the market price of natural gas along with the potential for carbon tax increases will add to its challenge of maintaining competitiveness in the future. (Exhibit B-1, pp. 37-38)

FEU reports it has experienced customer migration to other energy sources and states that some of this may be due to gas price volatility. In taking this position, FEU cites the 2008 Residential End Use Study (REUS) which concludes that "the increase in the real price (nominal prices adjusted for inflation) of natural gas over the long-run is contributing to the decline in use rates". Further, the authors of the study note that price spikes could induce customers to turn natural gas heating systems off in favour of readily available alternative secondary heating sources.

FEU reports that information in the 2008 REUS indicates that on average 3 percent of FEI and 11 percent of FEVI customers have made a main space heating fuel change in the last five years with a net shift away from natural gas to electricity. The Utilities report that this is a unique occurrence as similar studies in 1993 and 2002 showed a positive gain for natural gas over electricity. Of the 3 percent of FEI customers who switched in the last five years, the study reports that 78 percent of these moved to electricity as their primary fuel source. As reported by FEU, the authors of the 2008 REUS state that increases in natural gas prices can cause fuel switching and based on this, the Utilities believe that natural gas prices have contributed to this migration. Further, based on these results, FEU asserts that natural gas hedging is of critical importance in mitigating market price volatility and its effects on natural gas rates. (Exhibit B-1, pp. 61-62)

In taking the position that a hedging program is critically important, FEU acknowledges that it is helpful only in dealing with competitiveness over the near term. As stated in the Filing "[a] narrowing of the gap between natural gas prices and electricity rates over the long run cannot be mitigated other than through a longer term hedging horizon. In other words, over the longer term it is the market that defines the competitive position of natural gas relative to electricity or other sources of energy." (Exhibit B-1, p. 5) FEU further acknowledges in response to BCUC 1.4.1.2 that because the hedging horizon extends out three years, its effectiveness is short term in nature and ultimately the natural gas marketplace and electricity rates will determine the competitiveness of natural gas over the long term. FEU also notes the impact of government policy and public perception towards energy and the role of natural gas on long term competitiveness.

With respect to the competitiveness objective, BCOAPO submits that its belief is that competitiveness of natural gas with other energy sources is in the ratepayer's interest. However, BCOAPO submits that this is best achieved through rigorous control of distribution and procurement at the utility level. (BCOAPO Final Submissions, p. 2) The CEC submits that a review of the competitiveness evidence is an indication of how the FEU has attempted to blend the management of short term price volatility with longer term competitiveness issues. The CEC states that FEU's treatment of competitiveness identifies the key comparative issues between gas and electricity as a heating source but fails in making a connection between competitiveness and price risk mitigation. After providing a lengthy list of examples taken from FEUs responses to IRs, the CEC concludes that the majority of the evidence does not provide support for the need for a price risk management objective designed to keep natural gas pricing competitive with electricity. (CEC Final Submissions, pp. 1-4)

In Reply, FEU states that the assertions of the BCOAPO and the CEC that the objective of maintaining competitiveness should not be part of the plan objectives is not based on the belief that competitiveness is an invalid objective. FEU states that the claim of the interveners is that the hedging strategy over the long run cannot mitigate the market forces which will ultimately determine natural gas and electricity rates which it views as an oversimplification. The Utilities argue that hedging can help with the near term maintenance of competitiveness for the three year hedging plan period. FEU further argues that "[m]arket price volatility can effect competitiveness in the near term as natural gas customers change their consumption behaviour or switch fuel sources based on the real or perceived view that natural gas is uncompetitive." FEU states that the CEC concedes this point in its submissions. In response to BCOAPO's assertions with respect to cost controls FEU notes that the Utilities do employ cost controls for distribution and operating expenses but they do not affect the cost of gas resources. Further, the Utilities state that procurement (Annual Contracting Plan) resources have limited ability to manage competitiveness and commodity rate volatility. (FEU Reply Submissions, pp. 2-3)

4.1.2 Moderation of the Impact on Rates from Gas Price Volatility

FEU believes that reducing rate volatility is a critical factor and improves the Utilities ability to compete with other forms of energy. With respect to rate volatility FEU asserts the following:

- Moderating market price volatility provides customer value.
- Customers have indicated that they desire a degree of rate stability.
- Customers accept this stability may come at reasonable cost.

To support its position FEU has cited a number of research studies which have been conducted to assess the importance of rate stability. (Exhibit B-1, p. 31)

i. Residential Customer Price Volatility Preferences Study

This study was conducted in February, 2005 by Western Opinion Research Inc. and was designed to survey customers concerning their tolerance for rate volatility. This study involved qualitative focus group research to identify the range of opinions on the subject and assist with preparing the questionnaire for the quantitative part of the study. Key findings included the following:

- Customers report that natural gas is one of the more significant monthly payments.
- Customers cannot afford large bill price increases.

The average customer tolerance for annual billing changes is $169 or 16 percent of the annual bill (with a range of 11 to 17 percent depending on the group they fit into).

Seventy percent of customers could tolerate bill changes of $100 or less.

With respect to this last point FEU interprets this to mean the tolerance of most customers is a maximum of $100 which is approximately 10 percent of an average yearly bill. In the study customers were provided with scenarios resulting from various approaches to natural gas price hedging. FEU reports that most customers surveyed were willing to participate less in downside rate movements if upside rate increases were correspondingly limited. These results were explained as indicating a concern with large bill increases as well as the impact of rate volatility on the ability to budget. (Exhibit B-1, pp. 63-64; Exhibit B-1, Appendix B)

ii. Residential Customer Focus Group

FEU reports that it recently conducted inquiries regarding preferences for rate stability in conjunction with a November 2010 focus group with customers enrolled in the Commodity Unbundling Program. Customers were given three rate scenarios (a fixed rate, a variable or market rate and a controlled rate with a tighter range than the variable rate) and asked to give their preferences. FEU reports that the majority favoured a controlled rate and were willing to accept less downside rate participation than the variable rate if upside increases were also limited. Customers stated preferences for rate stability and less bill surprises are reasons for the selection of this option. FEU submits that the results of this focus group provide validation in the current time period of the findings from the earlier 2005 study. (Exhibit B-1, p. 64-65)

iii. Customer Threshold for Gas Supply Volatility Study

In December 2004 Enbridge Gas Distribution (Enbridge) commissioned Ipsos-Reid to conduct a study designed to assess the customer's threshold for natural gas volatility. The study focused on residential and small commercial customers and assessed their sensitivity to rate volatility and risk management strategy preferences. Key findings of this study were as follows:

- Most customers place more importance on maintaining a steady rate than getting the lowest possible rate.
- Most customers wanted their utility to manage potential risk for large commodity price fluctuations.
- About half of the respondents expressed $100 as a tolerable fluctuation in their annual bill.
- Customers prefer rate stability to avoid large bill surprises and for budgeting purposes.

While acknowledging that this study was conducted in another jurisdiction, FEU notes that the results were not inconsistent with those in its jurisdiction and it appears that customers have a desire for a level of rate stability and avoid fluctuations in bills that can occur in the absence of volatility mitigation strategies. (Exhibit B-1, pp. 65-66)

BCOAPO's position is that a reduction in the volatility of gas market prices on behalf of ratepayers is a laudable goal but they should not be asked to bear the risk for this activity at any cost. The Intervener attributes significant reductions in gas commodity bill volatility solely to the existence of mechanisms such as gas cost deferral accounts and the practice of quarterly rate adjustments pointing out that to some degree the Utilities concur. BCOAPO notes that the information provided by the Utilities with respect to hedged versus unhedged rates in response to an information request include the impact of these two mechanisms. Additionally, it summarizes the impact of the program by stating that "it is not at all clear that the estimated historical reduction in volatility was worth the costs incurred." What is clear to the BCOAPO is that the approach has led to significant ratepayer cost increases citing gains in only four of the last eleven years totalling $116.8M and losses totalling $742.9M for the remaining seven years. Further, the Intervener points out that in spite of what it describes as a dismal hedging record, the FEU, in response to CEC IR 1.1.2, states that the primary PRMP objectives have been met at a reasonable cost over the last ten years. (BCOAPO Final Submissions, pp. 2-6)

The CEC submits that the evidence in the filing and IRs is supportive of the existence of natural gas price volatility. Further, the CEC states the evidence also supports the view that price volatility affects customer perception of short term competitiveness which in turn has an impact on the customer's decision-making process with respect to changing heating application fuel types. It saw no need to repeat the evidence to support these positions and submits that it is in strong support of the need for an objective to moderate the impact on rates from natural gas price volatility. (CEC Final Submissions, p. 4)

In Reply, FEU acknowledge the support of this objective from the CEC and state that the concerns raised by BCOAPO relate to questions as to whether what was achieved was worth the costs incurred rather than whether this is an important objective. The Utilities also comment upon the recent unprecedented market declines and their impact upon hedging costs and state this is not indicative of past hedging performance or that going forward. In FEU's view, the proposed hedging strategy which allows for greater use of options places it in a better position to cap high prices and also participate in any price declines. (FEU Reply Submissions, p. 3-4)

4.1.3 Reduction of Risks Due to Price Disconnects

FEU describes a period of disconnection occurring "when increased demand in the Pacific Northwest including British Columbia creates a lack of gas delivery capacity at Huntingdon causing Sumas prices to increase significantly and disproportionately above other regional hub prices such as Station 2 and Alberta prices." The Utilities maintain that the management of the Sumas price exposure becomes critical, especially during a price disconnection period and is believed to be an important objective of the hedging strategy. An example of price disconnection provided by FEU includes the winter of 2000/01 when natural gas prices peaked at $60.96/GJ and experienced unprecedented price volatility. More recently, in November 2010 during a particularly cold weather period, the Sumas price disconnected from the AECO and the Henry Hub price and spot prices which had traded below $4.00 US/MMBtu ran up to almost $5.50 US/MMBtu. FEU concludes that this latest example highlights the fact that even though the supply of natural gas in North America is abundant, price increases and volatility can occur when regional demand increases.

FEU has traditionally used Sumas-AECO Basis Swaps where the Sumas price exposure is converted to an AECO floating price plus a fixed Sumas-AECO price differential to remove the Sumas floating pricing risk in order to manage this risk within the commodity and midstream portfolios. FEU points to the fact that pipeline capacity has not kept up with demand growth in recent years. Accordingly, the Utilities believe there is greater potential for the Sumas basis to widen from AECO and Station 2 during periods of high demand than in the past. During such periods, the Sumas price will increase to draw gas away from Alberta and cover interruptible T-South transportation charges. The Utilities note that basis hedging serves primarily to protect against cold weather, high demand Sumas price disconnects. (Exhibit B-1, pp. 68-72)

BCOAPO offers no specific comments with regards to the objective related to regional price disconnects. The CEC views the issue of price disconnects as being a special case of price volatility and belongs under this objective rather than meriting a specific objective of its own. (CEC Final Submissions, p. 5)

FEU submits it is best as a separate objective as it is distinct from more general market price volatility and requires separate handling in terms of hedging strategy. In addition, keeping it separate distinguishes it as being unique to this region as are constraints effecting Sumas pricing and serves to highlight its importance in the management of customer risk.

4.2 Proposed Hedging Strategies

To assist in the review of the existing hedging program and objectives and provide recommendations for the future, FEI selected RiskCentrix an external consultant with much experience in the design and implementation of commodity risk mitigation programs for both gas and electricity utilities. The RiskCentrix review concluded that the FEI objectives for the PRMP were appropriate and consistent with those of other utilities as were the existing hedging program strategies. RiskCentrix then focused on ways to improve the existing hedging program to continue to achieve objectives with greater focus on cost effectiveness.

RiskCentrix recommended a hedging strategy with a number of key elements designed to achieve the objectives. Included in these are the following:

- programmatic hedging to reduce volatility on a scheduled basis;
- defensive hedging to respond to potential increases above specific price levels;
- value hedging to take advantage of favourable price opportunities; and
- Basis Swaps for Sumas price risk management.

The RiskCentrix recommendation is for a monitor-and -respond style of risk mitigation as opposed to one which is primarily programmatic. FEU states that this approach allows for mitigation of customer rate increases and reduces the potential for intolerable hedging costs. Key refinements to the existing hedging program recommended by RiskCentrix include a reduction in reliance on programmatic hedging, the setting of rules for defensive hedge responses, the addition of value screening criteria for incremental hedge accumulation and a greater reliance on call options. The FEU proposed hedging strategies are outlined below. (Exhibit B-1, pp. 84-85)

4.2.1 Programmatic Hedging

The RiskCentrix recommendation calls for 25 percent or less of both winter and summer volumes to be hedged programmatically. This is a significant departure from the past where FEI typically hedged 60 percent of winter and 45 percent of summer volumes programmatically. The programmatic hedges will be done with fixed price swaps in equal increments monthly based on a schedule which extends out 3 years. (Exhibit B-1, pp. 85, 89)

4.2.2 Defensive Hedging

Defensive hedging is used only on an as needed basis. It is only in those cases where potential price movements would have the effect of increasing costs above a predefined tolerance level that a defensive hedge would be initiated. FEU explains that the tolerance targets for defensive hedging will be integrated with predefined tiers based on customers' tolerable bill preferences and electric equivalent commodity component benchmarks. FEU will use tiers where the first defensive price target will be related to the maximum tolerable customer rate increase and other tiers related to predetermined electricity benchmarks. FEU notes that this strategy will be implemented with fixed price swaps and options. To allow for gradual ramping into a defensive posture, defensive hedges will be made within a two year window of the term being hedged. (Exhibit B-1, pp. 85-86, 90)

4.2.3 Value Hedging

As outlined by FEU, value hedging using fixed price swaps will be used to take advantage of favourable pricing opportunities and is similar to accelerated hedging the Utilities have used in the past. It is the RiskCentrix recommendation that screening data criteria based on the shape of the forward price curve be added and this type of hedging only be used when the forward price curve is in contango or where forward prices increase further out in time. FEU states that value hedging would be implemented only when a specific predefined price target was reached. They note that the rate at the beginning of this year of $4.568/GJ is the lowest commodity rate since inception of the Commodity Cost Reconciliation Account (CCRA) and that setting a target below $4.50/GJ would assist in maintaining low commodity rates and provide value for the customer. Noting that the FEU are competitively challenged for new or retrofit hot water heating customer's falling into the Step 1 rate, and assuming 50 percent of BC Hydro's rate increases are approved, the Utilities note the benchmark target is near $4.00/GJ to $4.50/GJ from 2011 to 2014. (Exhibit B-1, pp. 87, 91)

4.2.4 Basis Swaps

The need for Basis Swaps to manage winter Sumas price exposure was discussed previously in Section 4.1.3. FEU reports that that this program will continue to be consistent with past practice. (Exhibit B-1, p. 91)

BCOAPO notes its understanding that the hedging proposal before the Commission does not suggest that FEU will continue with historical practices. In spite of this, the position of BCOAPO is the Commission Panel should reject what the Utilities "believe to be 'reasonable costs' associated with hedging activities in whatever form" and, presumably, the filing itself. BCOAPO notes that it does not find compelling evidence to support the view that the hedging strategy being proposed will come at any lower cost to ratepayers. On the contrary, it notes that the possibility for highly volatile costs and impacts exists if FEU is to embark on their proposal as filed. BCOAPO submits that there is a lack of evidence on the record suggesting that the proposed strategy has been tested in practice and concludes the PRMP is therefore inordinately risky to ratepayers. (BCOAPO Final Submissions, pp. 6-7)

The CEC submits that FEU has made credible enhancements to their hedging programs and there is likelihood for improvement in performance in the 25 to 30 percent range. Nonetheless, the CEC asserts that the PRMP will provide only a modest level of price risk management at significant cost to its customers. However, the CEC 's position is price hedging programs should be a matter of choice for the customer and offered as one of a number of alternatives for price risk management to FEU's customer base. CEC suggests it would be helpful in aiding with customer retention. (CEC Final Submissions, p. 18)

FEU in its Reply takes exception to the position of BCOAPO and the arguments raised that challenge whether the hedging is able to achieve the objectives. Specifically, FEU respond to assertions regarding evidence supporting whether the strategy has been tested in practice, the possibility of volatile costs and high risk to ratepayers, the methodology for deploying defensive hedging, the impact of a greater use of options, the accuracy of statements related to trying to "time or beat the market" and the lack of discussion or analysis regarding probable outcomes of the strategy and impact on the reduction of bill volatility. (FEU Reply Submissions, pp. 7-10)

With respect to the CEC's submission that customers be given the choice to select a hedging program as one of a number of options, the FEU responds that there are a number of key reasons why hedging should continue on behalf of customers:

- A variable rate option with no hedging exposes customers to greater rate volatility than they are used to or willing to tolerate.
- The use of a price stability rate rider (as discussed in Section 4.4.1) may not prove to be significantly different than using deferral account balances and in the event balances become high, may come with similar risks or cost. Moreover, such a vehicle would have no effect on the underlying market prices effecting gas costs and thus be limited in mitigating rate volatility.

- Either option would require significant expenditures for development and execution of the separate service which would be recovered from ratepayers. (FEU Reply, pp. 12-13)

4.3 Existing Rate Stabilization Tools

This Section provides an overview of the other tools and/or mechanisms that FEU currently uses to stabilize customer rates by reducing the impact of volatility in gas commodity markets. In addition, the position of the Company as well as the views of the Interveners regarding these mechanisms is summarized.

4.3.1 Overview of the Existing Mechanisms

Gas Cost Deferral Accounts

Gas cost deferral mechanisms essentially collect the difference between forecast and incurred gas costs with the balances to be recovered from customers or refunded to customers at a later date through rates. This way deferral accounts allow some rate stability by deferring the impact of commodity market volatility on gas costs. Two deferral accounts are used to stabilize rates.

The Commodity Cost Reconciliation Account became effective April 1, 2004. Since that time deferral account balances, on a net of tax basis, have generally been within a ± $50 million range.

The Midstream Cost Reconciliation Account (MCRA) contains the midstream costs which comprise a mixture of costs which are fixed in nature (related to storage and transportation demand charges) and those which are variable in nature (related to storage injections and withdrawals as well as seasonal commodity purchases and sales). (Exhibit B-1, pp. 75-76)

Quarterly Rate Adjustment Mechanism

Currently FEI reviews the CCRA rate on a quarterly basis and, as a rule, uses a CCRA rate adjustment mechanism with a 95 percent to 105 percent under/over recovery dead band on the rate change trigger ratio in determining whether or not a rate adjustment is required. The midstream cost recovery rates or MCRA rates are also reviewed quarterly as part of the FEI quarterly gas cost reports filed with the Commission. However, under normal circumstances, the MCRA rates are typically reset annually. (Exhibit B-1, p. 76)

Use of Storage

The effective use of storage is another tool used by FEU to manage price volatility and gas cost in order to enhance price stability. Storage provides both operational and financial benefits and enables FEU to achieve the Annual Contracting Plan (ACP) objective of balancing supply reliability, portfolio diversity and cost minimization. (Exhibit B-1, p. 78) Specifically, storage with associated transportation service provides a physical or “natural hedge” by realizing and locking in the differential between summer and winter prices. The underlying intent is to inject gas in the summer months when gas prices are generally lower for withdrawal in the colder winter months when prices tend to be higher. (FEU Final Submission, p.21).

Equal Payment Plan

The Equal Payment Plan (EPP) provides customers with equal monthly bill payments for a twelve month period, based on their previous year’s consumption volumes. The monthly EPP instalments are automatically reviewed every three months during the plan, and are adjusted if necessary to reflect significant changes in usage or rates. Approximately 31 percent of FEU customers are signed up for this billing option. (Exhibit B-1, p. 66)

Commodity Unbundling – Customer Choice

Both residential and commercial customers can also enrol in the Commodity Unbundling Program to ensure rate stability. In this program, called Customer Choice, customers can purchase their natural gas from marketers at a fixed rate for one to five year terms instead of purchasing their commodity supply from FEI at its quarterly adjusted rate. Currently, approximately 16 percent of residential and commercial customers are enrolled with a marketer. (Exhibit B-1, Review Report, p.67)

4.3.2 FEU Submissions

FEU submits that it uses the above mechanisms to complement hedging in moderating rate impacts and maintaining competitive rates for natural gas customers. It further submits that "while all of these mechanisms help to some degree in achieving the objectives, they cannot individually or collectively replace the value of cost effective hedging in fully meeting the objectives." (FEU Final Submission, p. 19) The following explanations provided either in the Review Report or in FEU responses to IRs, are put forward to support the Utilities' position:

FEU on Deferral Accounts

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. (Exhibit B-3, BCUC 1.8.3)

Generally deferrals do not serve as an alternative to an effective hedging program. A short-duration deferral mechanism adds modest additional stability when used in conjunction with a robust hedge program; it is inferior as a stand-alone approach in the absence of a hedge program. Furthermore, the risk of deferral accounting is that deferrals could accumulate to unsustainable levels resulting in the need to ultimately pass through more radical costs. (Exhibit B-1, Appendix A of the Review Report, p. 24)

FEU on the Equal Payment Plan

Under the EPP consumers will ultimately have to pay the rate impacts of any market price fluctuations as each customers' account is trued up to the actual usage and rates at the end of the twelve months. Indeed, during periods of extremely volatile market prices EPP customers may also be subject to quarterly rate changes. The hedging program, unlike the deferral accounts and EPP, directly mitigates market price volatility by affecting the underlying commodity cost of gas. (FEU Final Submission, p. 21)

FEU on the Use of Storage

Despite the benefits provided by storage it is not a substitute for hedging for the following reasons:

(i) The amount of storage that can physically be contracted is primarily limited by the availability of third party storage capacity and the associated pipeline transmission capacity for delivery to the service areas during the winter months. (Exhibit B-7, BCOAPO 2.18.1)

(ii) Contracting for storage capacity increases associated storage and transportation fixed demand charges. Furthermore, because storage balances are usually drawn down at the end of each winter, the price protection associated with storage capacity is generally limited to a single season. With an effective hedging program, price protection can be provided for several years out in time. (Exhibit B-1, Review report, p. 85, FEU Final submission, p. 22)

(iii) Storage injections during the summer could be impacted by any adverse market price movements, such as price increases resulting from production disruptions caused by seasonal hurricanes.

In conclusion, while the use of storage does play an important role in managing the impacts of market prices on gas costs, it must be balanced with the hedging strategy and use of deferral balances in combination with the appropriate amount of index-based supply. (Exhibit B-8, CEC 2.8.1, FEU Final Submission, p. 22)

4.3.3 Intervener Submissions

BCOAPO

BCOAPO submits that "there is an insufficient basis that would allow parties, and the regulator, to conclude that approval of this Filing is warranted and we urge the BCUC reject the Utilities' Price Risk Management Plan on the grounds that (i) the regulatory onus on the utilities has not been met and (ii) approval could expose ratepayers to high costs with low benefits." (BCOAPO Final Submission, p. 9)

BCOAPO notes that there are significant reductions in gas commodity related bill volatility due solely to the existence of gas cost deferral accounts and the quarterly rate adjustment mechanism. Specifically, BCOAPO states the evidence has not established that the estimated historical reduction was worth the costs incurred. Furthermore, it submits FEU was unable to separately quantify reduction in volatility due to hedging vs. other mechanisms used. (Exhibit B-4, BCOAPO 1.2.1, 1.2.2)

Finally, BCOAPO does not consider the net hedging costs over the 2000-2010 period reasonable and submits there is no compelling evidence on the record that the proposed hedging strategy will come at any lower cost to ratepayers, nor that it has actually been tested in practice. (Exhibit B-3, BCUC 1.1.1, BCOAPO Final Submission, p. 6)

In reply, FEU submits the evidence on deferral accounts is that "these mechanisms do not provide the same degree of volatility reduction as hedging." Furthermore, FEU submits that "deferral accounts do not impact the underlying market prices and have limitations with respect to impacting short-term borrowing capacity." (FEU Reply Submission, p. 12)

CEC

The CEC submits that it sees the existing alternatives for price risk management as providing some interesting options for customers. The base quarterly price adjustments and deferral accounts seem to smooth out much of the price volatility but leave the question of how to handle the significant peak prices that come along from time to time. The CEC tends to agree with FEU's position that quarterly pricing and deferral account mechanisms are complementary to other price risk management.

The CEC also agrees with FEU that the EPP is essentially an additional complementary option for customers. Finally, the CEC submits that gas marketer contracts with price certainty provide an option for customers and that FEU should continue to offer this option. (CEC Final submission, pp. 12-16)

4.4 Other Options for Rate Stabilization

To assess the benefits of hedging as compared to other utility alternatives to stabilizing natural gas prices and their impact on customer bills, other options should be explored as well. The CEC provided some suggestions which are addressed below.

4.4.1 Customer Price Stability Fund

The CEC submits the evidence demonstrates that FEU customers would be substantially better off with a self-hedging Price Stability Fund. At a minimum, the CEC states customers might prefer the choice between a self-hedging price risk management option and a market risk management option. In terms of numerical verification, the CEC points out that had FEU adopted a policy of offering a price stability rate rider to customers of 5.25 percent of the commodity purchased over the eleven years of performance data provided, the fund would have generated approximately $400 million over that time period. If that amount had been applied to reduce the unhedged price peaks experienced over the period, the CEC submits, FEU customers would have enjoyed far greater price stability than what was achieved by hedging. Indeed, the $400 million would have been enough to produce essentially flat rates throughout the eleven year period. (Exhibit B-3, BCUC 1.1.1.1, CEC Final Submission, p. 15)

This contrasts to the hedging programs offered which cost customers some $626 million over the eleven years. The CEC submits that the hedging program achieved only very modest amounts of rate smoothing for the peaks, amounting to less than 33 percent of a full flattening of the rate peaks. (Exhibit B-3, BCUC 1.1.1.1, Exhibit B-4, BCOAPO 1.2.2) In conclusion, the CEC submits that the FEU needs to look much more closely at customer self-hedging as a price risk management tool. (CEC Final Submission, p. 15)

4.4.2 Customer Market Supply

The CEC notes that some customers would see the benefit of not paying the premium for hedging and submits that FEU is not currently making this option available. The CEC further submits that it would be highly relevant to customers to have the option for an 8.2 percent lower commodity cost without the hedging. (Exhibit B-1, Appendix B, p.4, CEC Final Submission, pp. 15-16) This would in effect provide the customer with the choice as to subscribing to the program.

4.4.3 Alternative Equal Payment Plans

As noted previously, the CEC agrees with FEU that the EPP is essentially an additional complementary option for customers to choose from for bill management. The CEC submits that FEU might find it useful to offer alternative EPP types, which provide more or less price stability at defined prices. (CEC Final Submission, p. 14)

4.4.4 Customer Choice for Price Risk Management

After reviewing the proposed price risk management enhancements proposed by the FEU the CEC acknowledges that the proposed enhancements may produce 25 percent to 30 percent improvement in the hedging program performance. However, the CEC still submits that the hedging program will only provide a modest level of price risk management for a significant cost to customers. Accordingly, the CEC further submits that "FEU should be permitted to provide an enhanced hedging option for consideration by customers and that it should be offered to customers to allow them to decide if the cost risk trade-off suits them."

In conclusion, the CEC submits that a hedged price option, a self-hedging option and no hedging option would represent an ideal suite of price risk management options to add to the existing mix. A customer choice of this nature would then allow the customers to decide the most reasonable trade-off to suit their personal circumstance. (CEC Final Submission, p. 18)

5.0 COMMISSION PANEL DECISION

5.1 Validity of Objectives

In Section 4.1, FEU outlined three objectives which were the basis for the PRMP. The proposed objectives involve maintaining the competitiveness of natural gas with other energy sources, moderation of the impact of gas price volatility and reducing risks related to price disconnects. The view of the Commission Panel is that these objectives can be separated into two categories; the need for competitiveness and the need to moderate natural gas price volatility as a means of stabilizing customer rates. These bear examination from the perspective of the FEU ratepayers who purchase gas as this group has been identified as the key stakeholder for these proceedings. We believe this will serve to assist in underlining the fact there are fundamental differences between the two and how they impact the gas purchasing ratepayer.

5.1.1 Need for Competitiveness

The Commission Panel finds that the need for an objective related to the competitiveness of natural gas with other energy sources has not been established.

The need for competitiveness speaks to the FEU position that it is in the customer's best interest that natural gas prices continue to be competitive with other energy options, principally electricity. FEU has outlined a scenario where there will be customer migration from natural gas to electricity if the competitive picture were to shift in favour of electricity. This in turn will lead to increased delivery rates and possibly result in an increase in electricity rates depending upon the reasons behind the change and the magnitude of customer migration. An interpretation of this is the customer is expected to fund the cost of a hedging program to mitigate what can best be described as a competitive business risk rather than a price risk with the ultimate effect being a stabilization of delivery costs. The Commission Panel is of the view that a Return on Investment (ROE) Hearing is a more appropriate forum for evaluating business risks and notes that in the most recent proceeding, FEU received a substantial increase in the level of ROE to compensate for increased business risk. The question arises as to why then is the gas customer being expected to bear the cost of the risks for which FEU is already compensated for within its approved rate of return. The Panel's answer is they should not.

Perhaps the more important consideration lies in the concept of competitiveness itself. The Commission Panel views the commodity price as just one of many elements affected by market forces which in concert determine the competitive position of natural gas relative to electricity and other energy sources. In addition, the Utilities must consider factors related to delivery costs as well as those affecting the cost of electricity itself. Considering only the commodity price and ignoring the potential for responding to competitive threats more broadly is in our view an inadequate response. This is especially important given FEU's admission outlined in Section 4.1.1 that well run hedging programs assist in dealing with competitiveness in the near term hedging horizon only. The Panel notes that a hedging program does not really deal with the issue of competition and the variability of the market but merely puts off the inevitable. A further consideration is that while an elimination of the gap between electricity and natural gas rates may occur over the long term, there is little to indicate this will occur over the nearer term covered by the hedging horizon.

The lack of rigorous analysis examining the hedging option against other options to mitigate competitive risk is also a concern to the Panel. This matter was queried in BCUC IR 1.2.1 where FEU was asked to "provide a detailed analysis on the risk issue, criteria that addresses the issue, the various alternatives, the pros and cons of the alternatives and the reasoning for the preferred alternative that best mitigates the risk." BCOAPO comments that this question was an opportunity to present the PRMP in a way "...that could demonstrate the appropriateness of the Proposal in terms of delivering ratepayer value for hedging dollars." BCOAPO further comments that FEU failed to seize this opportunity, a sentiment with which the Panel agrees. (BCOAPO Final Submission, p. 8) A comprehensive review such as that requested would have resulted in a more robust discussion of the competitiveness risk and outlined a broader range of alternatives.

Further, in determining the merits of an objective related to the competition with electricity, the Commission Panel believes it appropriate to consider the British Columbia's Energy Objectives as set out in the *CEA*, specifically objective (h) which is "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia." (*CEA*, Part 1, 2(h)) It should be noted that the *CEA* objective (c) contemplates that at least 93 percent of the electricity in British Columbia be generated from clean or renewable resources. In this proceeding FEU has asserted that the PRMP can, in the short term, mitigate the impact of government policies that impact the competitiveness of natural gas to other energy forms or shape public perception that reduces the demand for natural gas. (Exhibit B-3, BCUC 1.11.1.1) The Panel's position is that it is not in the public interest to have a PRMP objective designed to mitigate the impact of an objective of government policy.

In summary, the Commission Panel bases its finding that the objective related to competitiveness of natural gas with other energy sources (principally electricity) is inappropriate for the following reasons:

- issues related to business risk have complexities beyond those of natural gas commodity cost and are more appropriately dealt with in the context of a ROE Hearing;

- in the long run the demand for gas versus electricity will not be driven by a PRMP but will be driven by market forces;

- in the current market environment short run competitiveness with electricity is seen to be largely driven by events of limited duration that cause market volatility, making this objective indistinguishable from the moderating of price volatility objective; and

- promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate.

5.1.2 Need to Moderate Natural Gas Price Volatility

FEU's position is that there is a need for an objective to moderate natural gas price volatility as a means of stabilizing customer rates. In addition, FEU has asserted that there is also a need for an objective to reduce the risk of regional price disconnects with specific reference to Sumas-AECO disconnects. The Commission Panel, while acknowledging that Sumas-AECO disconnects are a unique circumstance requiring different tactics, agrees with the CEC that this is a volatility-related issue and sees no benefit in separating the two. Accordingly, the Panel will consider the risk of regional price disconnects as being addressed within the discussion of the need to control price volatility in order to stabilize customer rates.

The Commission Panel finds that moderating the volatility of natural gas prices is a reasonable goal for the Utilities to pursue. **However, the Panel rejects the notion that it necessarily follows that the proposed PRMP is the most cost effective approach or solution.**

As noted previously in Section 4.1.2, neither BCOAPO nor the CEC take issue with the need to take steps to moderate price volatility. The CEC has further pointed out the link between customer perception of short term competitiveness and its impact on the customer decision-making process as to the choice or change of heating fuel. In addition, various studies cited by FEU generally support the view that there is a decided customer preference for rate stability and there are limits to the size of annual bill changes customers indicate they are willing to accept. However, in the Commission Panel's view the key issue is not whether controlling volatility is a desirable outcome but how this outcome can be best achieved in a cost effective manner. In the following sections, 5.2 and 5.3 the Panel will address whether there is a need for a formal PRMP before examining some of the existing tools and potential for new alternatives to manage this volatility.

5.2 Need for a Formal Price Risk Management Plan

In the previous Section 5.1 the Commission Panel provided its assessment of the validity of the three PRMP objectives and found that the issue is really about volatility. In making this determination and rejecting the FEU's position that there is a need to be competitive with other energy sources (principally electricity) the question arises as to whether sufficient justification remains to support the need for a PRMP as proposed. While acknowledging that managing volatility is in the best interests of ratepayers, the Commission Panel is not persuaded that the PRMP as proposed is a requirement or even the most cost effective solution to the problem. **Accordingly, with the exception noted below, the Panel rejects the FEI 2011-2014 PRMP dated January 27, 2011.**

As outlined in Table 1 in Section 3.2, over an 11 year period commencing in 2000, FEI has experienced hedging costs which total $626.1 million. Based on a total commodity cost of $7.636 billion (inclusive of hedging costs or gains) what this means is that over this 11 year period FEI ratepayers have paid a premium to the market natural gas rate of 8.9 percent. It is understood that the two worst performance years in 2009 and 2010 were anomalies where natural gas prices dropped at an unprecedented rate and the FEI program experienced costs of $296.9 million resulting in a ratepayer premium of over 36 percent. However, relying upon the FEU response to BCUC IR 1.1.1, the Panel notes that the costs for the three preceding years (2006-2008) totalled $265.8 million. This converts to a ratepayers natural gas rate premium of 12.5 percent which is also well above the 11 year average. In spite of these snapshots over the last 2, 5 and 11 year periods FEU states that "[o]n average over the past decade, the direct hedging costs have been modest in light of the benefits of reduced market price volatility and maintaining competitiveness for customers." (FEU Final Submissions, p. 13) The Commission Panel does not consider these costs to be modest nor are we persuaded that the benefits justify these costs. On the contrary, the Panel considers forcing customers to pay a premium of 8.9 percent on average over the last decade as being a very high cost for marginal benefits. Add to this the fact that over the last five years customer premiums have consistently exceeded this level and the results of this program from the perspective of 'reasonable cost' in the Panel's view, can best be described as dismal.

FEU enlisted an outside consultant, RiskCentrix which has been instrumental in assisting the Utilities in making significant changes to the proposed program strategies. The Commission Panel acknowledges this and accepts the position that on a go-forward basis the results of the PRMP would potentially be more responsive to market changes. However, the Panel notes that improved responsiveness over the current program sets a low baseline and there is no data or analysis presented to suggest that hedging will effectively balance risk and cost objectives. As outlined in 5.1.1, we also note the lack of analysis examining the hedging option against a range of other alternatives. As a result, the Panel remains unconvinced the need for the PRMP has been adequately established.

FEU states throughout its evidence that the measure of this type of program is not gains or losses but whether the objective is achieved at a reasonable cost. Further, FEU uses the analogy of homeowner insurance which is used to protect against uncertain events and has equated this to hedging programs. The Panel views this analogy as a reasonable characterization, which in these circumstances, is useful. However, we would like to point out there is at least one major difference between the two situations. That is the customer purchasing home insurance has various coverage options including whether a policy will be purchased. With the proposed PRMP there are no customer driven options or the ability to opt out. Given the past performance of this program and the potentially high impact on ratepayer bills, the Commission Panel is in agreement with the submissions of CEC regarding the need for choice (CEC Final Submissions, p. 11) and finds that, at the very least, the decision to be involved with a hedging program, should be a choice made by the individual customer.

The Panel does accept that there are ongoing issues with price disconnects leading to pricing volatility which are most appropriately dealt with by the current practice of Sumas-AECO Basis Swaps. As pointed out previously, the Ontario jurisdiction which no longer has a hedging program does have access to substantial storage which could be used to mitigate these types of problems. This is not the case in British Columbia where the amount of and accessibility to storage is limited and other options to control such price disconnects must be pursued. The Sumas-AECO Basis Swaps program has proved to be a relatively low risk, low cost strategy which, as outlined in Table 17 of the Filing, has proved successful over time. **Accordingly, the Panel approves those elements of the PRMP related to the usage of Sumas-AECO Basis Swaps.**

In rejecting the full PRMP, the Commission Panel does not dismiss the view that there is a need for additional measures to control volatility. In Section 5.3 which follows we will discuss some of the existing means to manage volatility as well as explore some of the other alternatives which have been raised in these proceedings.

5.3 Alternatives for Rate Stabilization

When determining whether to endorse the price risk management primary objectives and whether to approve the 2011-2014 Price Risk Management Plan, the Commission Panel also considered how the proposed hedging program compares to other alternatives available for FEU to stabilize natural gas prices and customer bills. Section 4.3 provided an overview of the existing rate stabilization tools while Section 4.4 addressed other potential options for rate stabilization. In rejecting the PRMP, the Panel gave significant weight to reasonable cost. Specifically, the past costly hedging performance and prospects of on-going high ratepayer bill impact and found that given the existing other mechanisms and the availability of other potential options, a mandatory hedging program is not in the public interest. In this Section the Panel explains its views regarding the other available rate stabilization mechanisms and the role they play in managing natural gas price volatility.

FEU outlined a multitude of factors that can adversely affect gas prices and volatility in the short term, for periods of several months or longer. Examples of those factors included supply disruptions such as pipeline constraints during peak demand periods, weather related supply disruptions such as hurricanes, and unusually hot summer temperatures. **The Commission Panel finds that these short term incidents can be managed by the existing alternative mechanisms in conjunction with the use of Sumas-AECO Basis Swaps.**

5.3.1 Existing Rate Stabilization Tools

As noted previously, a number of rate stabilization tools are currently in use. These include gas cost deferral accounts, equal payment plans and the Customer Choice program. The purpose of these measures is to stabilize rates by reducing the number and frequency of price changes and thereby reduce volatility. These measures are addressed below:

Gas Cost Deferral Accounts

To assess the effectiveness of the existing programs in controlling price volatility the Panel first reviewed the Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance which were established in 2001 by Commission Letter L-5-01. Attributes of Deferral Account and Gas Cost Rate Setting Methodologies included in the Guidelines provide a framework for analyzing these tools and are reproduced in Appendix B. The key attributes are as follows:

- Rate Stability
- Price Transparency
- Size of Deferral Account
- Efficiency of Process

As noted previously, the deferral account balances since 2004 have generally been within a ± $50 million range and there is general agreement among the participants that the program has been successful in moderating rate impacts in the short term. This point was further supported by the Report on the CCRA and MCRA Deferral Accounts and Rate Setting Mechanisms submitted to the Commission by FEU on March 10, 2011. Based on that report, by Letter L-40-11 the Commission approved further enhancements to the 2001 Guidelines designed to reduce the need for small CCRA rate changes and moderate the growth of MCRA deferral account balances which are addressed annually. **Considering the criteria established in the 2001 Guidelines, the FEU evidence and Intervener submissions, the Commission Panel finds that the existing rate stabilization tools and mechanisms, enhanced as described above, continue to serve the intended purpose.** Furthermore, the deferral account balances seem to remain in a reasonable range, which means that the credit and liquidity risks are being managed. In supporting the continued use of these tools the Panel acknowledges that while deferral accounts provide some smoothing, they do not affect or help manage the underlying commodity prices.

Equal Payment Plan

The Equal Payment Plan is designed to level out payments over a year based on consumption levels in the previous year. The Commission Panel notes that 31 percent of FEU customers have chosen this option which indicates there is a desire among certain customers to have a steady rate throughout the year and to control volatility. While recognizing that this tool has no impact on the cost which will ultimately be paid by the customer, the Panel is persuaded this is a useful tool as it allows the ratepayer the option of stabilizing prices and allowing the impact of price volatility to be dealt with over a longer time period.

Commodity Unbundling – Customer Choice

The evidence that some 16 percent of residential and commercial customers are enrolled with a gas marketer demonstrates the existence of a group of customers preferring choice who are comfortable committing to a multi-year fixed price contract which guarantees commodity price stability. The Commission Panel notes that this program provides the ultimate in stability and protection against significant upward price movement. However, it offers no participation in the event that prices drop significantly as they have in recent years. Because of this, we are of the view that this program is a good fit for the group of customers who require price stability only but is less attractive to those who prefer to pay market price or at least participate in downward price movement when it occurs.

The Commission Panel believes each of the existing price stabilization mechanisms has a role to play both currently and in the future. However, we acknowledge that other than the Customer Choice commodity unbundling program, the existing mechanisms may not be effective in dealing with longer periods of considerable price volatility should they occur in the future. Therefore, FEU should continue to explore other alternatives; in particular, alternatives that would enable it to manage potential longer periods of persisting price volatility.

The Commission Panel believes the main reason for a utility not to hedge is the likelihood that the price-protection benefits from hedging will not justify the inherent costs. This is particularly the case during periods when relatively stable prices are expected. As discussed in Section 3.1, the natural gas industry has seen a dramatic turnaround in prices since 2008, and there are projections that shale gas may be able to supply the North American gas market adequately for decades at reasonable, more stable prices. More than ever, the Panel finds that in this new world the expected future value of hedging may be diminishing and benefits offered by other mechanisms can outweigh hedging. Under these circumstances, the Commission Panel believes that it is of utmost importance to provide customers a choice when it comes to rate stability and the price they are willing to pay for it.

For the reasons discussed above, the Commission Panel has rejected the FEI 2011-2014 Price Risk Management Plan. Should FEU, after reviewing the Decision, still believe that further steps to manage market gas price volatility and rate stability are required, the Panel urges FEU to explore new alternatives. In this regard, the Commission Panel wishes to emphasize the importance of choice as a principle. The Panel acknowledges the FEU reply submissions regarding the CEC proposals, especially the cost concerns. The Panel also notes that these proposals are largely untested and would require further analysis of the underlying assumptions.

Nonetheless, the Panel suggests FEU consider the CEC proposals among others. First, FEU is encouraged to consider the potential of offering an optional Customer Price Stability Fund. As described in Section 4.4, by way of a rate rider as a percentage of gas commodity purchased, customers would in effect be self-hedging and providing more stability. Second, FEU should consider offering an enhanced hedging program for customers, on an optional basis, along the lines recommended in the filing. After reviewing cost and risk trade-offs, customers can then determine whether insurance in the form of hedging would suit their personal circumstances. In other words, a customer can decide whether the cost of hedging is an appropriate premium for “peace of mind.” In an optional hedging program, the Panel would expect the participants to cover the full cost burden. If FEU finds that alternative options such as these are warranted in the future, the Commission Panel invites FEU to submit a new filing for Commission’s consideration.

5.4 Commission Panel – Concluding Remarks

The Commission Panel would like to add a few concluding remarks. Firstly, we do not want to leave the impression that there is only limited concern for ongoing rate stability and the impact of potential future volatility. With the current price of gas at levels which have not been seen in years, the Panel acknowledges that the potential for downward movement of the price of natural gas is limited and the potential for upward movement is greater. However, we also note that in light of the recent exploitation of shale gas, the likelihood for more stable natural gas prices is significantly greater and the risk of dramatically higher natural gas prices, excepting short periods of price disconnects, is significantly lower than it has been in many years. This is not to say that the risk of more dramatic increases in natural gas prices has been eliminated. On the contrary, factors such as the potential for growth in LNG exports and the possibility of a more dramatic economic recovery leading to increased consumption are just two of the myriad of events which could affect future natural gas prices. However, the Commission Panel’s position is that hedging is not the way to deal with the potential for price increases. The key is managing volatility not price which is a result of market forces. The Panel has no desire to “close the door” on the consideration of all future hedging options. Given a change in external conditions, we would consider proposals on behalf of ratepayers to help in mitigating the relevant risks. However, we would like to be clear that the need for a formal hedging program as proposed has not been established by this Filing and given the performance of the PRMP over the last 10 years, a regular ongoing program applying to all ratepayers is not in the public interest.

REGULATORY PROCESS

Terasen Gas Inc. (TGI) and Terasen Gas (Vancouver Island) Inc. (TGVI)
(collectively Terasen Gas)

An Application for Approval of the Price risk Management Plan
Effective April 2011–October 2014

REGULATORY TIMETABLE

ACTION	DATES (2011)
Intervener and Interested Party Registration	Friday, March 4
Commission Information Request No. 1	Friday, March 11
Intervener Information Request No. 1	Wednesday, March 16
Participant Assistance/Cost Award Budgets	Friday, March 18
TGI Response to Commission and Intervener Information Request No. 1	Friday, March 25
Commission Information Request No. 2	Friday, April 1
Intervener Information Request No. 2	Friday, April 1
TGI Response to Commission and Intervener Information Request No. 2	Friday, April 8
TGI Written Final Submission	Tuesday, April 26
Intervener Written Final Submission	Tuesday, May 3
TGI Written Reply Submission	Tuesday, May 10

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.