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April 8, 2011

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, BC
V6E 2N7

Attention: Mr. James L. Quail, Executive Director

Dear Mr. Quail:

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 British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization et al ("BCOAPO") Information Request ("IR") No. 2

On January 27, 2011, the Companies filed the Application as referenced above. On April 1, 2011, the BCOAPO 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 BCOAPO IR No. 2.

If there are any questions regarding the attached, please contact 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.

1.0 Reference: BCUC IR 1.1.1.1

1.1 To what factor(s), does FortisBC attribute its significant – in comparison to total cost of commodity purchased – hedging losses in 2009 and 2010 for both FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc.?

Response:

Please refer to the response to BCUC IR 2.1.1.

1.2 Do the responses to the referenced IR indicate that hedging activities increased the "Total Commodity Purchased" costs (as defined below the tables) borne by system gas customers of FortisBC Energy Inc. and of FortisBC Energy (Vancouver Island) Inc., by over 22% in 2009 and 2010?

Response:

Yes. Please also see the response to BCUC 2.1.1.

1.3 For each of the tables, please disaggregate the row entries in the columns entitled "Total Commodity Purchased" to separately the components (i) net storage activity, (ii) commodity resale (for FortisBC Energy Inc.), and (iii) peaking gas resale (for FortisBC Energy (Vancouver Island) Inc.), for each year shown in the table.

Response:

As requested, the following tables disaggregate the "Total Commodity Purchased" for each year for the FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. tables provided in the response to BCUC IR 1.1.1.1.

FortisBC Energy Inc.

Year	Commodity Cost including Hedging * ($millions) (A)	Net Storage Activity* ($millions) (B)	Commodity Resale* ($millions) (C)	Total Commodity Purchased* ($millions) (A+B+C)
2000	778.1	(40.8)	(162.8)	574.5
2001	988.6	(19.3)	(205.6)	763.7
2002	646.1	29.2	(48.3)	626.9
2003	819.8	(38.0)	(60.0)	721.8
2004	897.9	(37.4)	(184.7)	675.8
2005	1,110.6	(26.0)	(311.0)	773.5
2006	955.2	10.1	(207.3)	758.0
2007	1,020.8	(18.0)	(198.2)	804.5
2008	1,109.9	(11.1)	(273.1)	825.7
2009	713.2	43.0	(136.1)	620.1
2010	634.5	12.1	(155.1)	491.5

***Commodity Cost includes hedging gains/costs.**

***Amounts shown are provided on a calendar-year basis for the Lower Mainland, Inland, and Columbia service areas.**

FortisBC Energy (Vancouver Island) Inc.

Year	Commodity Cost including Hedging * ($millions) (A)	Net Storage Activity* ($millions) (B)	Peaking Gas Resale* ($millions) (C)	Total Commodity Purchased* ($millions) (A+B+C)
2000	47.3	(3.1)	-	44.2
2001	69.8	(3.2)	-	66.6
2002	52.5	(3.3)	-	49.2
2003	74.3	(3.4)	-	70.9
2004	82.8	(5.2)	(5.8)	71.9
2005	104.9	(5.2)	(5.4)	94.3
2006	99.8	5.5	(12.3)	93.0
2007	117.8	2.0	(27.5)	92.3
2008	135.6	(4.7)	(27.8)	103.1
2009	93.2	7.4	(18.7)	82.0
2010	87.2	0.4	(19.6)	67.9

***Commodity Cost includes hedging gains/costs, and hedging activity for FEVI began in 2002.**
***Amounts shown are provided on a calendar-year basis for FEVI.**

1.4 Has either FEI or FEVI ever written put options related to potential future gas commodity sales by the Companies?

Response:

No, the Utilities have never purchased put options related to future gas commodity sales. Note that the "writing" is done by the put seller, whereas the Utilities are purchasers of options written by financial counterparties as part of the price risk management activities related to its physical gas portfolio. Regardless, the Utilities do not participate in put options related to its gas supply portfolio.

2.0 Reference: BCUC IR 1.3.1.2

Preamble: The response to this IR states, in part: *"The Companies would not generally favor options in a relatively low market price environment since potential downside in market prices is limited."*

2.1 Please indicate how the Companies know that a low price environment at any particular time or for any particular period is likely to occur in the future.

Response:

The Utilities do not know that a low price environment at any particular time or for any particular period is likely to occur in the future. As discussed in Section 3.4 of the Review Report, the multiple supply and demand factors in the natural gas marketplace make future price predictions extremely difficult.

However, the Utilities do monitor commodity markets and are aware when market prices are low relative to historical values or commodity rates, or when market prices are near or below levels where natural gas production, on an average basis, is likely uneconomical. As discussed in Section 3.2 of the Review Report, Figure 4 on page 18 shows that most natural gas production is uneconomic at prices below $4 per MMBtu. Therefore, sustained market prices below this level are likely to result in reduced production levels which, ultimately, results in higher prices in the future. This is reflected in the enhanced hedging strategy. For example, with forward prices at their lowest levels in several years, the value hedging price target of $4.25 per GJ per the FEI 2011-2014 Price Risk Management Plan enables the Utilities to lock in value for customers relative to historical values and below the current commodity rate of $4.568 per GJ

2.2 Please explain why opportunities such as call options would not generally be favoured in a relatively low market price environment to limit future upside price risk and future increased volatility.

Response:

Call options are generally not favoured in a relatively low market price environment. This is because call options have the most value in a high price environment where there is the potential for significant future downward market price movements. In this high price environment, if market prices should eventually decline, the call options allow for downward

price participation, whereas fixed price swaps do not, while still providing upside market price protection. In a low price environment, fixed price swaps limit future upside price risk without the cost of option premiums and effectively mitigate future volatility without the potential for significant out-of-market outcomes given that market prices are already depressed.

For example, an AECO fixed price swap for the upcoming winter 2011/12 is currently trading at about $4.05 per GJ. A call option that limits market price movements above this level with an equivalent $4.05 per GJ strike price would require a $0.46 per GJ premium. So market prices would have to fall below $3.59 per GJ (or $4.05 per GJ less the $0.46 per GJ premium) in order to provide more value than the fixed price swap.

3.0 Reference: BCUC IR 1.3.1.9

3.1 In addition to the factors mentioned in this response, does option valuation also depend on the risk-free interest rate assumed? If so, please explain how the Companies determine this rate.

Response:

Option valuation does take into consideration the interest rate within the option premium. For upfront call option premiums, where the premium is paid at the time of transacting the call option, the premium is discounted by the interest rate value from the current period to the term to maturity on a present value basis. For deferred call option premiums, where the premium is paid to coincide with the time of the physical price settlement for the term, the interest rate is included in the valuation of the option premium. Therefore, the difference between deferred and upfront call option premiums is dependent on the term to maturity of the call option and the current market interest rate and is generally not significant given the recent low level of interest rates.

The Utilities typically transact deferred call option premiums to coordinate payments of hedging settlements and option premiums with underlying physical gas supply payments.

4.0 Reference: BCUC IR 1.4.1.10

4.1 Do the Companies believe that "market values" for natural gas include forward prices, indexed prices, and other fixed prices for future delivery, in addition to spot prices?

Response:

Yes, the Companies believe that "market values" for natural gas include forward prices, indexed prices and other fixed prices for future delivery in addition to spot prices. The Companies have interpreted the term 'other fixed prices for future delivery' to mean the market based premiums, or discounts, on physical gas purchases for future delivery.

4.2 Do the Companies agree that volatility would be zero for any portfolio components of their gas supply arrangements that were underpinned by fixed price contracts for future commodity?

Response:

Yes, the Companies agree.

5.0 Reference: BCUC IR 1.4.2.3

5.1 Have there been any cases in the past when a gas marketer defaulted on their obligations to supply customers resulting in the affected customer(s) "returning to system," i.e., becoming dependent on the Companies for commodity supply?

Response:

FEU understands this question to be asking if at any time has a Gas Marketer failed and their customers necessarily returned to the Companies' commodity supply. In summer 2008, two Gas Marketers failed, including Wholesale Energy Group and CEG Energy.

Under the Essential Services Model ("ESM"), FEI is responsible for midstream resources including contracting and managing transportation and storage requirements, and providing balancing and peaking services. Gas Marketers, under the ESM are not required to provide any balancing services as their delivery requirements are determined on a 100% load factor basis, without any true up to actual consumption at period end. FEI is the supplier of last resort under the ESM. In this role, FEI is obligated to make up any difference between the authorized quantity and the delivery requirement at each receipt point on a mandatory basis through a sale of backstopping gas to the Gas Marketer at the receipt point. Backstopping gas sales are triggered in the event there is a shortfall between the authorized quantity and the delivery requirement at a receipt point at the completion of the Evening Nomination Cycle.

Since its inception, the ESM has performed as expected. The model addresses the numerous short-term backstopping events that occur annually, and notably, gas continued to flow to customers without interruption when Wholesale Energy Group and CEG Energy ceased operations in summer 2008. During these situations, Terasen Gas (now FEI) acted as supplier of last resort until each failing Gas Marketer negotiated the sale of their book of customers to other companies.

Other Gas Marketers were attracted to Wholesale Energy Group's and CEG Energy's books of customers, which primarily included contracts negotiated in 2007 when natural gas pricing was relatively high and rising. By mid 2008, gas prices had moderated and supply was readily available at lower cost. Had gas prices continued to rise in 2008, FEI believes the sale of these contracts to other Gas Marketers would have been unlikely. Gas Marketers would not have been able to secure the necessary supply at a cost that would allow for a positive return on investment. As such, it is anticipated that affected customers would have necessarily returned to FEI supply. This scenario can arise in the future; the ESM and proposed hedging strategy provide residential customers assured commodity supply even when a Gas Marketer's book of customers represents an unattractive investment.

5.2 Do the forward prices indicate futures prices traded on the NYMEX?

Response:

The Utilities do not know which forward prices BCOAPO is referring to in this question.

NYMEX natural gas futures prices are traded on the futures exchange market with Henry Hub as the delivery location of the NYMEX natural gas contract. Futures prices and basis differentials for other price hubs such as AECO and Sumas are typically traded on over-the-counter markets such as with market makers (such as banks) via the phone or on a centralized exchange such as the Intercontinental Exchange ("ICE").

6.0 Reference: BCUC IR 1.5.1.1

6.1 Do the Utilities agree that it is not possible, ex ante, for any entity to know how to construct a supply portfolio that will result in the lowest possible commodity prices *ex post*?

Response:

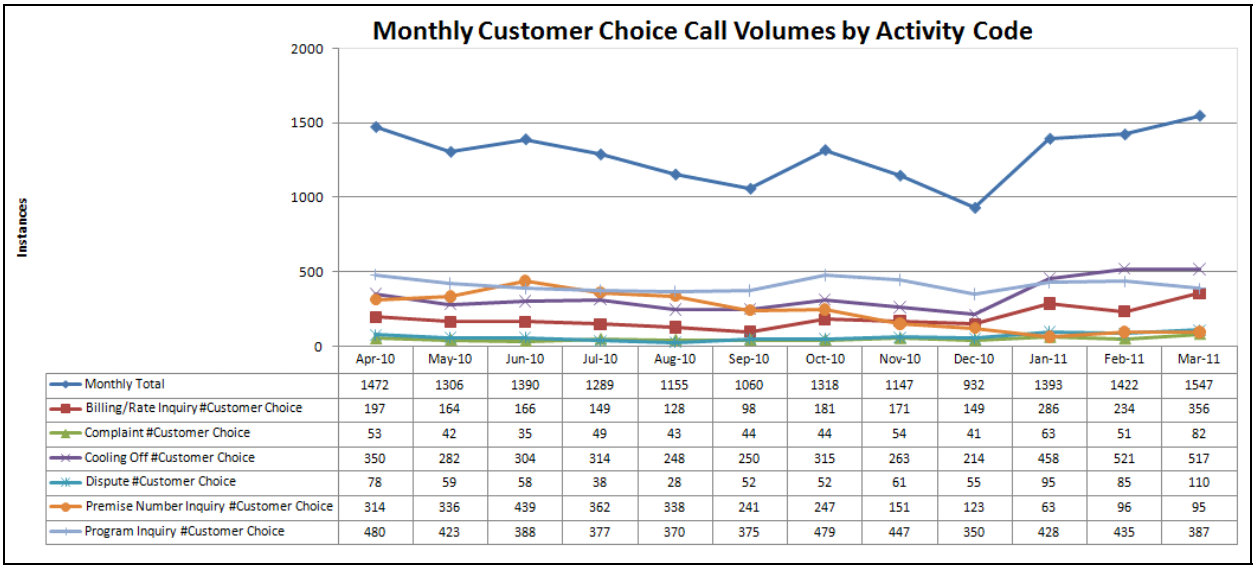
Yes, it would be extremely unreasonable to expect any entity to be able to construct a supply portfolio, ex ante, that would be guaranteed to result in the lowest possible commodity prices ex post.

6.2 Have any customers communicated complaints regarding gas marketers' prices or policies to either of the utilities?

Response:

Yes, many customers have communicated complaints regarding gas marketer's prices and/or policies. These queries and concerns are evidenced by FEU Contact Centre call statistics, negative media coverage, and the dispute activity adjudicated by the BCUC. A discussion of these three areas follows.

The table below depicts Customer Choice related call volumes handled by the FEU Contact Centre for the 12-month period ending March 2011. During the period, the Contact Centre handled 15,431 calls related to Customer Choice. This represents about 12.5% of those customers currently participating in the program. About 70% of these calls, represent either billing/rate inquiries, complaints, cancellation enquiries (i.e., cooling off drops), or disputes. Call levels pertaining to the program remain high, despite low sales and declining enrolment levels.



	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11
Monthly Total	1472	1306	1390	1289	1155	1060	1318	1147	932	1393	1422	1547
Billing/Rate Inquiry #Customer Choice	197	164	166	149	128	98	181	171	149	286	234	356
Complaint #Customer Choice	53	42	35	49	43	44	44	54	41	63	51	82
Cooling Off #Customer Choice	350	282	304	314	248	250	315	263	214	458	521	517
Dispute #Customer Choice	78	59	58	38	28	52	52	61	55	95	85	110
Premise Number Inquiry #Customer Choice	314	336	439	362	338	241	247	151	123	63	96	95
Program Inquiry #Customer Choice	480	423	388	377	370	375	479	447	350	428	435	387

Complaints about Gas Marketer activity is further evidenced by negative media attention, particularly following the program's launch in late 2007 and early 2008. Additional consumer protection policies were established in early 2008 to better safeguard customers from inappropriate sales tactics. In particular, the BCUC made third party verification calls mandatory. However, media attention continues to view the fixed contracts unfavourably. For example, the CBC published an article in March 2010 entitled, "Natural gas customers stuck with costly contracts."[1] The article suggested that, "Thousands of B.C. residents who switched to new natural gas providers after deregulation are now paying significantly more than market rates and discovering they can't get out of multi-year contracts."[2] The article is still located on the CBC website. Almost 250 responses to the report are available for review. Almost all consumer concerns noted regard Gas Marketer pricing, policies or sale tactics.

A news report by CTV first made on Oct. 11, 2010 called, "What you need to know before leaving Terasen," is another good example of the media coverage that has typified public perceptions. The story starts, "A natural gas customer is sending a warning after switching companies for what she thought was a deal – but ended up paying twice as much."[3]

[1] CBC, story available at http://www.cbc.ca/news/canada/british-columbia/story/2010/03/08/bc-gascontracts.html
[2] CBC, story available at http://www.cbc.ca/news/canada/british-columbia/story/2010/03/08/bc-gascontracts.html
[3] CTV BC, story at http://www.ctvbc.ctv.ca/servlet/an/local/CTVNews/20101011/bc_gas_marketer_101011/20101011?hub=BritishColumbiaHome

Gas Marketer sales approaches have even led one irate consumer to write and maintain an ongoing cautionary blog at http://bcgasmarketer.blogspot.com/. FEU is also aware of a professionally designed website that tells customers how they can "trick" the system and get out of contracts without penalty.

Despite declining program participation and low enrolment activity, the BCUC continues to deal with high dispute levels. Consumer safeguards implemented after the program launched in 2007 have helped to mitigate disputes. However, Commission staff still processed approximately 320 disputes in March 2011. Many of these were "courtesy drops," in which the Gas Marketer chose not to contest the issue with the customer. Other instances related to contracts that consumers felt they were paying an inappropriately high price for the Gas Marketer's fixed rate, or that the contract had been established inappropriately.

To summarize, customers have often voiced concerns regarding gas marketer pricing practices, penalties and/or policies. Their concerns are demonstrated by FEU Contact Centre call statistics, negative media coverage, and the extensive dispute activity that must be adjudicated by the BCUC each month.

7.0 Reference: BCUC IR 1.6.1.3 and BCUC IR 1.4.3.1

7.1 Please confirm that no Core Market Administration Expense costs related to the Utilities' gas supply activities are allocated to gas marketer customers. If unable to so confirm, please explain.

Response:

A portion of Core Market Administration Expense ("CMAE") costs related to the Utilities' gas supply activities are allocated to gas marketer customers. Because gas supply activities involve management of both commodity and midstream resources, it is appropriate to allocate CMAE costs related to midstream management activities to gas marketer customers who benefit from these activities. While customers can choose their commodity supply provider, the Utilities are still responsible for ensuring appropriate and cost effective midstream resources meet customer load requirements, as per the Essential Services Model ("ESM"). CMAE costs are allocated 70% to midstream related activities and 30% to commodity related activities based on the management resources required for these functions.

8.0 Reference: BCUC IR 1.6.1.5

8.1 Have either of the utilities received expressions of interest from customers for a fluctuating commodity rate completely underpinned by daily spot supply purchases?

Response:

No.

9.0 Reference: BCOAPO IR 1.1.4

Preamble: The response to this IR states, in part: *"On an annual bill basis, this (hedging cost) equates to an approximate annual cost of $56."*

9.1 For a typical residential customer whose commodity is provided by the utility and for comparative purposes, what would be the annual commodity charges, not including the aforementioned $56? If appropriate, please provide averages for the various representative customer types within the residential class.

Response:

Table 1 below illustrates the annual commodity only charges for an average residential customer consuming about 95 GJ per year. The figures are presented for both the unhedged and hedged CCRA rates for all full years beginning January 2005.

Table 1: Annual Commodity Charges for Hedged and Unhedged CCRA Rates

	Consumption Weighted Unhedged CCRA Rate Average	Consumption Weighted CCRA Rate Average	Average Residential Consumption	Annual Commodity Bill for Unhedged and Weighted CCRA Rate	Annual Commodity Bill for Hedged and Weighted CCRA Rate
Jan05-Dec05	$8.37	$7.83	95	$795.44	$743.70
Jan06-Dec06	$8.16	$8.50	95	$775.11	$807.73
Jan07-Dec07	$6.85	$7.42	95	$651.18	$704.67
Jan08-Dec08	$7.68	$7.64	95	$729.21	$726.01
Jan09-Dec09	$5.29	$6.25	95	$502.60	$594.02
Jan10-Dec10	$4.09	$5.08	95	$388.18	$482.22

FEI does not have data available differentiated by different customer types within the residential class.

10.0 Reference: BCOAPO IR 1.2.1

Preamble: The response to this IR states, in part: *"… the Equal Payment Plan ("EPP") is not reflected in approved published rates but rather a mechanism available to individual customers to smooth the impact of volume consumption on their bills over a 12 month period…"*

10.1 Please provide a brief explanation as to how the EPP monthly amount to be charged to a given consumer is calculated. For example, does the calculation involve expected future prices over the 12-month period, in addition to expected monthly volumetric consumption?

Response:

The Equal Payment Plan (EPP) provides customers with the ability to budget their natural gas costs and smooth out payments over the course of a year rather than having higher payments during the winter period and lower payments during the summer months. A key objective of the EPP is for enrolled customers to end their plan year with a balance that is as close to zero as possible.

To determine a customer's EPP installment amount, the Company uses the customer's prior year consumption history and current rates as the basis for estimating the EPP monthly installments for the next year. As well, a 5% contingency factor has historically been used to address usage and rate increases that can occur during a year. The monthly EPP installments are automatically reviewed every three months during the plan year and are adjusted up or down if required to reflect significant changes in usage or rates.

Note that although the EPP smoothes the monthly amounts a customer will pay over the course of a year, each customer's EPP account is trued up to the actual usage and rates at the end of the year meaning a customer will ultimately pay the same total annual amount whether they elect to participate in the EPP or not.

11.0 Reference: BCOAPO IR 1.2.2

11.1 Regarding the graph provided in response, have all hedging cost components been removed from the line "FEI Rate – Unhedged"?

Response:

As stated in the response to BCOAPO IR 1.2.2, while it is not possible to precisely restate the historical results to incorporate all the changes that may have occurred in the absence of any commodity hedging, FEI has undertaken to adjust the historical and recorded gas cost data to remove the commodity hedging gains and costs related to the CCRA portfolio from the historical recovery rates to develop a proxy of the "unhedged" rate.

No adjustments were made to the Core Market Administration Expenses, and the midstream rates were left unchanged as the small amount of hedging in the historical midstream costs amounts to less than ± $0.01/GJ in the historical annual midstream rate.

11.2 For each of the full years shown on this graph, please provide a comparison of annual commodity costs for a typical residential under the "FEI Gas Rate" and under the "FEI Rate Unhedged."

Response:

Please refer to the response to BCOAPO IR 2.9.1.

11.3 For each of the full years shown on this graph, please provide the annual bill for a typical residential customer exclusive of gas commodity costs.

Response:

Table 1 below summarizes charges exclusive of commodity charges for full years from January 2005 to December 2010. The Carbon Tax charges, which commenced on July 1, 2008, are also included as part of the charges that customers incur.

Table 1: Residential Customer Charges (Exclusive of Commodity Charges)

	Average Fixed Basic and Delivery Charges	Average Midstream Charge	Average Carbon Tax Charge	Total Charge (excl. of commodity charges)	Average Residential Consumption	Annual Cost
Jan05-Dec05	$3.99	$0.66	N/A	$4.64	95	$441.18
Jan06-Dec06	$4.12	$0.36	N/A	$4.47	95	$425.01
Jan07-Dec07	$3.97	$0.86	N/A	$4.83	95	$458.85
Jan08-Dec08	$3.95	$1.33	$0.50	$5.77	95	$547.95
Jan09-Dec09	$4.31	$1.02	$0.62	$5.94	95	$564.68
Jan10-Dec10	$4.64	$1.73	$0.87	$7.24	95	$687.33

12.0 Reference: BCOAPO IR 1.2.4

12.1 Please explain the circumstance surrounding the year (2007) in which the unhedged CCRA rate was less volatile than the hedged CCRA rate.

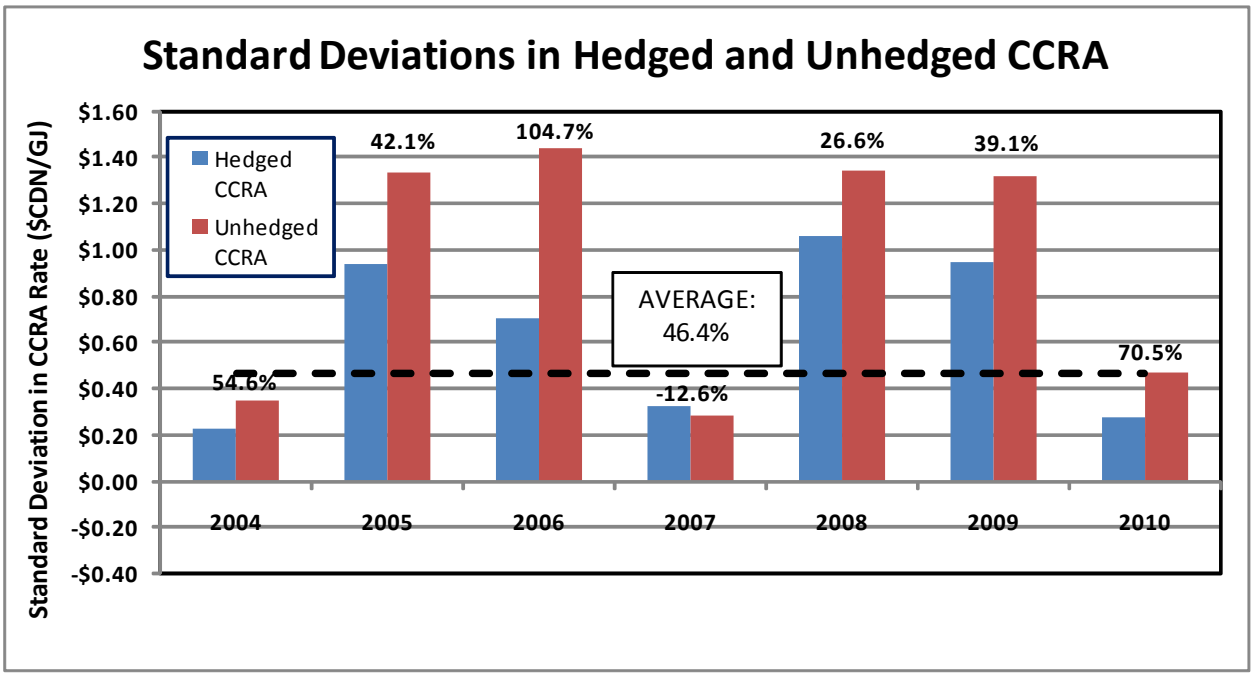
Response:

As explained in the response to BCOAPO IR 1.2.2, FEI has undertaken to adjust the historical forecast and recorded gas cost data to remove the commodity hedging from the historical CCRA rates to develop a proxy of the "unhedged" rate. A number of assumptions were made in determining the unhedged rate, including that the historical CCRA rate was recalculated to approximate an unhedged rate by leaving the effective dates of the original rate changes unchanged and by adjusting the commodity cost forecasts to remove the hedging and also adjusting the CCRA deferral balances to remove the hedging impacts. The resultant "FEI Rate – Unhedged" line shown on the graph in the response to BCOAPO IR 1.2.2 demonstrates the generally wider band for the unhedged rates compared to the hedged rates. As the data provided in the response to CEC IR 2.11.3 indicates, there are a number of quarters under the unhedged scenario where a CCRA rate change could have been triggered outside of the effective dates of the original rate changes (for example, the unhedged scenario at Line No. 11, shows the Revenue to Cost Ratio in Column 13 as 88.9%, outside of the 95%-105% deadband range, indicating that a rate increase would have been required).

In 2007, the hedged CCRA rate was $7.662 CDN/GJ from January 2007 to October 2007 at which time it was reduced to $6.926 CDN/GJ. At the same time the hypothetical unhedged CCRA rate was $6.641 CDN/GJ on January 2007 and then increased to $7.284 CDN/GJ on October 2007. The reduction in the hedged CCRA rate was larger than the increase in unhedged CCRA rate and thus resulted in the unhedged CCRA rate to be about 13% less volatile than the hedged CCRA rate during that time period.

Bearing in mind that the CCRA rates are established based on a 12-month prospective forecast of gas costs and the projected current deferral balance, and subject to quarterly review, it is not surprising that over a narrow time period there may be occurrences when the unhedged rate was less volatile that the hedged rate. However, on an overall basis, hedging has proven to reduce market price volatility quite significantly over the course of the past seven years, as illustrated in Figure 1 below. The hedged CCRA rate has been about 46% less volatile than the unhedged CCRA rate from 2004 to 2010.

Figure 1: Standard Deviations in Hedged and Unhedged CCRA Rate



13.0 Reference: BCOAPO IR 1.2.5

13.1 Absent identifying counterparties to each of the transactions, could the Utilities provide details of all hedging instruments used by year as requested in the original IR? If so, please provide them; if not, please explain why not.

Response:

In order to be responsive, FEI has provided the details of all hedging instruments by year, absent identifying counterparties to each of the transactions in Attachment 13.1 being filed confidentially and only to the registered parties in this proceeding. However, FEI does not believe this information is relevant in terms of reviewing the objectives of the proposed Price Risk Management Plan.

FEI would also like to make clear that all previous hedging activity and transactions were implemented according to prior Price Risk Management Plan that were approved or accepted by the Commission and compliant with the FEI governance policies, as discussed in the response to BCUC IR 1.3.1.5. Furthermore, hedging activity reports, including details of each transaction, are provided to the Commission on a monthly and quarterly basis.

13.2 Hedging costs appear to be substantial for each year from 2006 onwards. In addition, for each hedging instrument employed since 2008 (and for all but one employed in 2007), the Companies have realized hedging losses. Please provide a high level commentary to accompany the hedging results shown in the tables provided in response to the referenced IR.

Response:

For hedging gains realized in 2003 to 2005, futures prices steadily climbed and peaked for this period in the summer of 2005 as a result of production disruptions due to Hurricanes Katrina and Rita. This spike in prices near the end of the 2003 to 2005 period resulted in material hedging gains.

Forward prices subsequently declined in early 2006 and then dramatically increased in late 2006 in response to below normal storage levels entering the winter heating season and colder

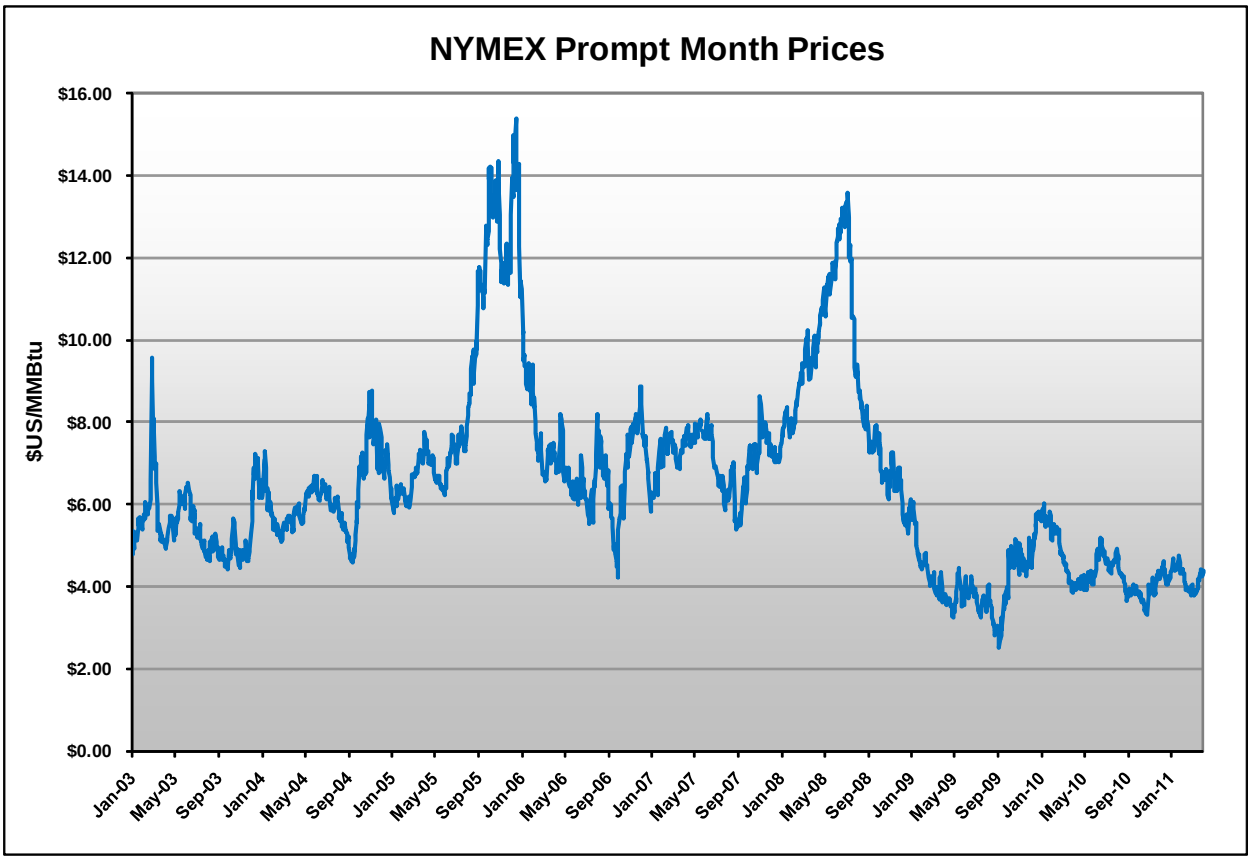
than normal winter temperatures. In 2007, prices dramatically declined entering the winter heating season as a result of higher than normal storage inventories. These extreme fluctuations in gas prices resulted in hedging costs for hedges that were implemented during the period of high prices (summer of 2005) in accordance with the approved programmatic hedging schedule. Hedges were implemented at these high prices throughout 2005 and in hindsight it appears that prices were high due the 'fear premium' associated with uncertainty regarding supply related to Hurricanes Katrina and Rita.

Hedging costs in 2008 were significantly lower than costs for 2006, 2007, 2009, 2010 due the rapid escalation of prices and subsequent and rapid decline in prices. In 2008, NYMEX prompt month prices spiked to over $13 US/MMBtu and then fell to about $5.50 US/MMBtu all in a span of about seven months, from July 2008 to December 2008. Hedges were implemented as prices were rising in response to prices reaching close to the competitive electric benchmark at the time and hedges were also implemented while prices were declining in the latter half of 2008. By the end of 2008, prices had declined below the level entering 2008 and this resulted in hedging costs for 2008, albeit less hedging costs than in the other four years.

For the period of 2009 and 2010, the Utilities experienced large hedging costs as a result of lower prices in response to the severe economic slowdown, depressed demand, and proliferation of shale gas resources. Hedges that were implemented at higher prices during 2008 eventually resulted in hedging costs in response to the low prices in 2009 and 2010.

Over the past number of years, the Utilities have mostly used fixed price swaps, at least 30% during summer periods and at least 45% during winter periods, as the primary financial hedging instrument. As a result of implementing fixed price swaps during rising and falling price markets any fluctuations in prices, as discussed earlier, will result in either hedging gains and costs. The proposed enhanced hedging strategy provides more flexibility to respond to changes in market environments and will reduce the likelihood of significant hedging costs while still providing appropriate protection for customers.

Figure 1: NYMEX Prompt Month Prices



13.3 To FortisBC's knowledge, did any of the utility's counterparties engage contemporaneously in any hedging or other financial activities with affiliated unregulated entities?

Response:

Please refer to the responses to the identical question at BCOAPO 1.2.10 and BCOAPO 1.12.3, and similar questions at BCOPAO 1.17.1 and BCOAPO 1.17.2.

14.0 Reference: BCOAPO IR 1.9.2

Preamble: The response to this IR states, in part: *"… the EPP provides customers with bill smoothing rather than rate smoothing."*

14.1 Do the Companies have any evidence about the preferences of vulnerable consumers, such as low-income residential households or seniors living on fixed incomes, with respect to whether they prefer bill smoothing as opposed to rate smoothing? If so, please provide this evidence.

Response:

The response to the referenced BCOAPO IR 1.9.2 explains that "bill smoothing" provided by the the EPP program is a function of levelling out the consumption impacts on monthly bills over a twelve month period. The EPP does not provide customers any protection against swings in the underlying cost of gas which would be provided by fixed rate offerings by marketers, a fixed price gas supply portfolio or the proposed hedging strategy. In the context of the referenced IR, this price protection provided was referred to as "rate smoothing". It is not a question of preferring "bill smoothing" or "rate smoothing"'; these tools provide customers value in different ways and can work together.

It is expected that vulnerable customers, such as low-income residential households or seniors living on fixed incomes, would be concerned with both bill smoothing where mechanisms such as the EPP can help with avoiding big swings in monthly budget requirements and "rate smoothing" which in this context refers to the underlying cost of gas that is recovered from those customers.

15.0 Reference: BCOAPO IR 1.12.2, Table 1

15.1 *Ex ante*, is the expectation that when entering a basis swap agreement with a counterparty, that gains and losses are equally likely for each of the parties?

Response:

No, when entering into a basis swap agreement with a counterparty, the expectation is not that the gains and losses are equally likely for each of the parties. While it is possible that, over the long run and on average, gains and losses could be equal, this will depend on regional demand, supply and market infrastructure developments. The expectation of the Utilities for a basis swap arrangement is mitigation of potential regional price disconnections at a reasonable or minimal cost over time. On the other hand, the expectation of the counterparty for a basis swap arrangement is the realization of a premium for undertaking this risk. Otherwise, the counterparty would not be willing to provide this basis swap arrangement on an on-going basis.

16.0 Reference: BCOAPO IR 1.12.2, Schedule 1

16.1 Please explain why basis swaps in May 2003 and August 2003 involved terms from April 2004 – October 2004, and April 2005 – October 2005 i.e., for periods outside of the gas-heating season and, in the latter case, for a period almost two years after the deal was entered into.

Response:

Basis swaps, in combination with fixed price swaps, were implemented for the summer 2004 and summer 2005 periods as an alternative method to manage the Sumas price exposure for the summer period within the portfolio. The Utilities have historically hedged both summer and winter price exposure given market price volatility can occur at any time and, at that time, both AECO and Sumas prices were hedged for the summer periods. In order to provide hedging diversity with respect to Sumas pricing at that time, NYMEX fixed price swaps combined with NYMEX-Sumas basis swaps were implemented. This resulted in an effective Sumas fixed price hedge based on fixed NYMEX prices with a fixed basis component. These hedges, along with Sumas fixed price swaps, were implemented to reduce Sumas price exposure in the portfolio for summer and winter periods further out in time. The Utilities hedged for periods further out in time (typically up to three years in the past) in order to smooth market price volatility. This implementation was consistent with the Price Risk Management Plans at the time, which were reviewed and approved by the Commission.

17.0 Reference: BCOAPO IR 1.13.1

Preamble: The response to this IR states, in part: *"Monthly priced gas at Station 2 and Alberta are priced off the AECO monthly index plus the prevailing market factor at the time of entering into the deal while monthly priced deals are priced off the Sumas Monthly Index plus the prevailing market factor at the time of entering into the deal."*

17.1 Please elaborate with respect to the prevailing market factors referred to in this response.

Response:

Gas that is purchased at the various indices will have an associated price or market factor that is added or deducted off the index price that is usually associated with the characteristics of that marketplace for supply and demand. For example, gas that is purchased at the Station 2 hub is priced off the monthly AECO NIT price which is the price in Alberta. Therefore, the gas price at Station 2 will either be available at the AECO NIT price plus or minus a market factor which fluctuates depending on the time of the year largely based on supply and demand conditions for gas at Station 2. If gas is purchased in Alberta at the same AECO NIT price, then there is also an associated market factor at that location, however, that market factor may not fluctuate as much as the factor at Station 2 due to the characteristic of that market for liquidity and availability of supply compared to the volatility level of the Station 2 market. Other factors affecting a market factor could include the contracting and availability of capacity in the region that is required to deliver gas production to market.

18.0 Reference: BCOAPO IR 1.14.1

18.1 Please provide (i) the total amount of storage that the Companies could contract for in order to inject gas in the summer for withdrawal in the winter, and (ii) the total amount of storage that the Companies do contract for in order to inject gas in the summer for withdrawal in the winter.

Response:

The Utilities assess the optimal amount of seasonal storage in the gas supply portfolio as part of the modeling performed to support the Annual Contracting Plan. The amount of seasonal storage that the Utilities could physically contract 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.

The amount of storage that the Utilities contract for depends on a number of other factors including market conditions, summer winter differentials, pricing of storage and transportation services, and availability of competitive alternatives. Furthermore, the Utilities contract at differing storage facilities based on the characteristics of the Utilities winter weather requirements such as seasonal winter loads and short term spikes arising from colder weather. All facilities are normally injected with supply to their maximum capacity in the summer months which are then utilized to meet the load in the winter months. However, some facilities require additional refilling during winter months that is explained further in this answer.

A portion of winter loads are met by seasonal storage facilities that are utilized primarily each day over the course of the winter months supplementing term and seasonal gas supply. These facilities are contracted to provide high capacity and deliverability over the course the winter months and a portion is also contracted to provide supply during the traditionally cooler months of December through February in a given year. The Aitken Creek facility in Northern BC is an example of a seasonal storage facility. Currently, there are limitations to the amount of capacity that can be contracted at the Aitken Creek facility.

Shorter duration storage resources, which are closer to the Utilities large load centers such as the Lower Mainland, are contracted to provide support during bouts of cooler or extreme winter weather that usually persist for no more than a few days at a time over the course of the winter months. These facilities provide high deliverability on a daily basis that aid in managing severe spikes in the load but their total capacity is subject to rapid depletion if utilized over a prolonged number of days. As a result, these facilities require refilling during the winter months when normal winter weather returns in order to be available for another bout of cold weather during the winter months. Services provided by the Jackson Prairie facility in Washington State and the Mist facility in Oregon State are examples of shorter duration market area storage facilities.

These facilities provide flexibility when needed especially on the intraday to balance the system. These facilities safeguard the Utilities from requiring to contract for expensive firm pipeline capacity backed by purchased gas supply. This type of gas supply may require contracting on a daily basis over the course of the winter months which may not be utilized for load while the pipeline capacity could require contracting on an annual basis resulting in costly demand charges. The contracting of short duration market area storage has become difficult for the Utilities over the last few years due to incremental contracting and demand from gas-fired generation facilities in the Pacific Northwest region.

The Utilities also own on-system peak shaving facilities that are available for gas supply during extreme or peak weather and emergency conditions. The Utilities Tilbury LNG facility at the Lower Mainland provides the coastal region with 660 TJ of capacity and 164 TJ/d for a period of four days at maximum sendout. In addition, the Utilities are in the completion stages of the new Mt. Hayes LNG facility on Vancouver Island that will become available for injection in the summer of 2011 for use commencing in the 2011/12 winter months. This facility will provide both the Vancouver Island and Lower Mainland regions with 1,614 TJ of storage capacity that is capable of delivering 161 TJ/d of supply for a period of ten days at maximum sendout. The Mt. Hayes LNG resource provides the Utilities with much needed relief in light of the tightening availability of market area storage resources in the region and also provides increased system capacity.

Currently, there are regional infrastructure constraints and limitations pertaining to the contracting of both seasonal and shorter duration market area storage facilities. Seasonal storage such as Aitken Creek has available capacity that can be contracted, however, it is constrained by the unavailability of firm transportation capacity required for delivery of supply out of the facility over to the Utilities market or load centers. Firm transportation is required to guarantee delivery of supply and Westcoast's T-North lateral that delivers supply to and from Aitken Creek is fully contracted resulting in no incremental firm capacity being available. As a result, the Utilities contract for seasonal winter term supply at Station 2 and Huntingdon in order to serve its customers during the winter months.

With regards to market area storage such as Jackson Prairie and Mist, the constraints for contracting are twofold. Firstly, there are severe capacity limitations at both facilities that prevent the Utilities from contracting at those locations. Secondly, in order to access supply from those facilities when required for load during cooler weather, there is a significant shortage of firm capacity on the Northwest Pipeline system that is necessary in order for supply to be delivered to the Lower Mainland. The Utilities were successful in acquiring a portion of capacity in February 2006 that resulted from an expansion of the Jackson Prairie facility, however the Utilities understand that there are very limited further cost effective expansion opportunities with these facilities.

The Utilities currently contract for over 30.0 PJ of storage capacity at NE BC, Alberta and Pacific Northwest facilities.

- In NE BC, the Utilities hold approximately 24 PJ of storage capacity at Aitken Creek with 150 TJ/d of associated deliverability and matching firm T-North and T-South transportation capacity. The amount of NE BC seasonal storage that the Utilities could contract for is currently limited by the amount of firm T-North capacity on the Spectra system.

- In Alberta, the amount of seasonal storage that the Utilities could contract for is limited by the SCP transportation capacity available to deliver into our service territory (approximately 114 TJ/d). The amount of storage that the Utilities do contract for is dependant on the value of the storage option versus other alternatives such as seasonal, monthly or spot gas purchases. The Utilities currently contract for 2 PJ of Alberta storage capacity with 33 TJ/d of deliverability.

- In the Pacific Northwest, the Utilities contract for approximately 4 PJ of storage capacity. The amount of storage services from the Pacific Northwest is limited by the availability of redelivery from the storage facilities to the service areas. Firm pipeline capacity is not often available and extremely costly.

Unlike other marketplaces such as Alberta and Ontario that have a large number of storage facilities with significant capacities, the BC marketplace is limited with a few facilities which face competition from all utilities that serve customers in the Pacific Northwest region. As discussed above, the total amount of storage that the Utilities could physically contract is also limited by the associated pipeline transmission capacity in the region that is required for re-delivery to the service regions served by the Utilities. The Utilities will continue to evaluate developments in regional contracting and infrastructure in order to evaluate and access incremental storage opportunities as they arise.

19.0 Reference: BCOAPO IR 1.15.2

19.1 Are the Companies aware of any statistical research which supports the assumption that real world daily gas spot prices follow a lognormal distribution?

Response:

Lognormal distribution of energy prices, including natural gas, is an industry-wide accepted assumption when attempting to model energy prices.

It should be noted that both daily spot *and* futures commodity prices follow a lognormal distribution and not just daily spot prices, like the question is assuming.

Research relating to lognormal distributions can be viewed at the following links:

Pages 12, 16, 19, 23, and 28 of the following link:
http://www.eia.doe.gov/emeu/steo/pub/special/pdf/2009_sp_05.pdf

Pages 2, 4, 5, and 6 of the presentation at the following link:
http://www.brattle.com/_documents/uploadlibrary/upload793.pdf

Attachment 13.1

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