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October 29, 2012

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Generic Cost of Capital Proceeding

FortisBC Utilities[1] ("FBCU")

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 2

On August 3, 2012, the FBCU filed its Written Evidence in the Generic Cost of Capital proceeding as referenced above. In accordance with Commission Order No. L-52-12 revising the Amended Preliminary Regulatory Timetable, the FBCU respectfully submit the attached response to BCUC IR No. 2.

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

Yours very truly,

on behalf of the FORTISBC UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

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[1] comprised of FortisBC Inc., FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc.

151.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 2.1.1, pp. 2-3; Question 97.1,

pp. 223-224; Question 98.2, p. 232

Throughput and Risk to Electricity Rates (Step 2 Rate)

In response to BCUC IR No. 1 Question 2.1.1, the FBCU show that FEI's natural gas throughput would have to decrease by 76 percent based on 2009 natural gas and Step 2 electricity rates, and by 83 percent based on today's natural gas and Step 2 electricity rates.

FBCU also state that "natural gas prices are at their lowest levels in over ten years and current forecasts indicate that a tightening of the supply and demand balance will lead to higher prices in the future. With higher natural gas prices and rates, less throughput would have to be lost for FEI's distribution margin to increase so that its natural gas rates became equal to BC Hydro's Step 2 electricity rates." [Emphasis added]

The FBCU present Table 1: Throughput Decrease Required to Increase FEI's Distribution Margin. The table shows the Residential Commodity charge of $2.977/GJ in 2012 and $6.103/GJ in 2009 as well as other input assumptions.

151.1 Please repeat Table 1 under the following four scenarios where FEI's "throughput that would need to be lost (%)" are equal to: (i) 50 percent, (ii) 25 percent, (iii) 10 percent, and (iv) zero percent. Holding all other assumptions constant, what would be the required increase in the Residential Commodity (or natural gas commodity price)?

Response:

While the requested analysis has been provided the FBCU do not agree that these calculations provide a basis to suggest that the FEU's business risks have decreased. Please see the response to BCUC IRs 2.152.1 and 2.198.1 for further discussion of this. Furthermore, this analysis does not include the carbon tax applicable to natural gas (approximately $1.50/GJ) and not electricity or the higher capital costs for natural gas versus electricity applicable for new equipment

As in the response to BCUC IR 1.98.2 the tables below assume thermal efficiencies of natural gas equipment relative to electric equipment of 60% and 90% in order to represent a reasonable range of older and newer gas equipment currently in use in the existing customer base.

The tables below summarize what residential commodity rate would be required to equate the natural gas rate to the BC Hydro RIB Step 2 under the following four scenarios of assumed throughput loss by FEI: (i) 50 percent, (ii) 25 percent, (iii) 10 percent, and (iv) zero percent.

For the scenario where the natural gas thermal efficiency vs. electricity is 60% and:

(i.) 50% of the throughput is lost, a commodity rate of about $7.93/GJ would be required;

(ii.) 25% of the throughput is lost, a commodity rate of about $10.25/GJ would be required;

(iii.) 10% of the throughput is lost, a commodity rate of about $11.03/GJ would be required; and

(iv.) 0% of the throughput is lost, a commodity rate of about $11.41/GJ would be required.

Figure 1: Resultant Commodity Rate for Throughput Scenarios (60% Efficiency for Natural Gas)

Line			Scenario (i)	Scenario (ii)	Scenario (iii)	Scenario (iv)
1	Rates					
2	BC Hydro Step 2 ($/GJ) assuming **60%** efficiency for gas	As at July 1, Converted to $/GJ	17.828	17.828	17.828	17.828
3						
4	FEI Residential Rates ($/GJ)					
5	Residential Midstream	As at January 1	1.365	1.365	1.365	1.365
6	Residential Commodity		**$ 7.926**	**$ 10.251**	**$ 11.027**	**$ 11.414**
7	Residential Delivery (excluding Riders) [1]		3.488	3.488	3.488	3.488
8	Residential Daily Basic Charge [2]	As at January 1	1.561	1.561	1.561	1.561
9						
10						
11	Volumetric Delivery Rate Needed	Line 2 - Line 5 - Line 6 - Line 8	6.98	4.65	3.88	3.49
12	Existing Volumetric Delivery Rate	Line 7	3.488	3.488	3.488	3.488
13	Increase in Delivery Rate Required	Line 11 - Line 12	3.49	1.16	0.39	(0.00)
14						
15	Approved Volumetric Residential Delivery Margin ($000s)	Line 12 x Line 19	243,776	243,776	243,776	243,776
16						
17	Throughput Required at Revised Volumetric Delivery Rate(TJ)	Line 15 / Line 11	34,945.0	52,417.5	62,901.0	69,890.0
18						
19	Existing Throughput (TJ) [3]		69,890.0	69,890.0	69,890.0	69,890.0
20	% of Existing Throughput	Line 17 / Line 19	50%	75%	90%	100%
21						
22	Throughput that would need to be lost (TJ)	Line 19 - Line 17	**34,945.0**	**17,472.5**	**6,989.0**	**(0.0)**
23	Throughput that would need to be lost (%)	1 - Line 20	**50%**	**25%**	**10%**	**0%**
24						
25	Notes:					
26	[1] Delivery margin on which approved rates set					
27	[3] Calculated as approved daily basic charge of $0.389 per day x 365.25 days / avg Residential Mainland customer use rate of 91 GJs					
28	[3] FEI Rate Schedule 1 Residential Volumes as approved in 2012/2013 RRA					
29						
30	Assumptions:					
31	-No loss in customer counts or basic charges. All change was based on customer use rate decreases					

For the scenario where the natural gas thermal efficiency vs. electricity is 90% and:

(i.) 50% of the throughput is lost, a commodity rate of about $16.84/GJ would be required;

(ii.) 25% of the throughput is lost, a commodity rate of about $19.17/GJ would be required;

(iii.) 10% of the throughput is lost, a commodity rate of about $19.94/GJ would be required; and

(iv.) 0% of the throughput is lost, a commodity rate of about $20.33/GJ would be required.

Figure 2: Resultant Commodity Rate for Throughput Scenarios (90% Efficiency for Natural Gas)

Line			Scenario (i)	Scenario (ii)	Scenario (iii)	Scenario (iv)
1	Rates					
2	BC Hydro Step 2 ($/GJ)	As at July 1, Converted to $/GJ	26.743	26.743	26.743	26.743
3						
4	FEI Residential Rates ($/GJ)					
5	Residential Midstream	As at January 1	1.365	1.365	1.365	1.365
6	Residential Commodity		**$ 16.840**	**$ 19.166**	**$ 19.941**	**$ 20.328**
7	Residential Delivery (excluding Riders) [1]		3.488	3.488	3.488	3.488
8	Residential Daily Basic Charge [2]	As at January 1	1.561	1.561	1.561	1.561
9						
10						
11	Volumetric Delivery Rate Needed	Line 2 - Line 5 - Line 6 - Line 8	6.98	4.65	3.88	3.49
12	Existing Volumetric Delivery Rate	Line 7	3.488	3.488	3.488	3.488
13	Increase in Delivery Rate Required	Line 11 - Line 12	3.49	1.16	0.39	0.00
14						
15	Approved Volumetric Residential Delivery Margin ($000s)	Line 12 x Line 19	243,776	243,776	243,776	243,776
16						
17	Throughput Required at Revised Volumetric Delivery Rate(TJ)	Line 15 / Line 11	34,945.0	52,417.5	62,901.0	69,890.0
18						
19	Existing Throughput (TJ) [3]		69,890.0	69,890.0	69,890.0	69,890.0
20	% of Existing Throughput	Line 17 / Line 19	50%	75%	90%	100%
21						
22	Throughput that would need to be lost (TJ)	Line 19 - Line 17	**34,945.0**	**17,472.5**	**6,989.0**	**0.0**
23	Throughput that would need to be lost (%)	1 - Line 20	**50%**	**25%**	**10%**	**0%**
24						
25	Notes:					
26	[1] Delivery margin on which approved rates set					
27	[3] Calculated as approved daily basic charge of $0.389 per day x 365.25 days / avg Residential Mainland customer use rate of 91 GJs					
28	[3] FEI Rate Schedule 1 Residential Volumes as approved in 2012/2013 RRA					
29						
30	Assumptions:					
31	-No loss in customer counts or basic charges. All change was based on customer use rate decreases					

152.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 2.1.1, pp. 2-3; Question 97.1,

pp. 223-224; Question 98.2, p. 232

Throughput and Risk to Electricity Rates (Step 1 Rate)

In response to BCUC IR No. 1, Questions 2.1.1, 97.1, and 98.2, the FBCU indicate that in practice the majority of residential customers would be at a blend of the Step 1 and Step 2 (electricity) rates for their space and water heating energy requirements, so a straight comparison of natural gas against the Step 2 rate does not provide a realistic picture. Smaller or more energy-efficient dwellings such as townhouses and condominiums may be capable of getting some or all of the energy need for space and water heating from BC Hydro's Step 1 block. The FBCU further state the Step 1 rate is a relevant comparator that must be considered.

152.1 At 2009 and 2012's natural gas and electricity Step 1 rates, please compute how much average natural gas throughput would need to be lost to drive FEI's distribution margin up so that its natural gas rates would become equal to BC Hydro's Step 1 electricity rate. Please show calculations and any assumptions in similar format as Table 1 on page 3 of BCUC IR No. 1 Question 2.1.1.

__Response:__

The following table shows the calculations and assumptions used to determine how much natural gas throughput would need to be lost to drive FEI's distribution margin up so that natural gas rates would become equal to BC Hydro's Step 1 electric rates at 2009 and today's rates. FEI does not, however, accept the implicit premise that the price differential allows for a loss of significant load without it impacting FEI's business risk. Please see the response to BCUC IR 2.198.1 in that regard.

The tables have been provided based on 60% and 90% thermal efficiencies for natural gas relative to electricity to represent the range of efficiencies of the mix of older and new appliances in the FBCU's residential gas customer base. The analysis below does not include the carbon tax of approximately $1.50/GJ that applies to natural gas and not electricity.

The table below provides results for the Step 1 electric rate and an assumed relative efficiency of 60% for natural gas compared with electricity. The table shows that FEI's natural gas throughput would have to decrease by 42% based on today's natural gas and Step 1 electricity rate to increase the delivery rate as requested in the question. The same calculation applied to the 2009 natural gas rates and the 2009 RIB Step 1 rate would not require an increase in delivery rates to achieve the requested result.

Table 1: Throughput Decrease Required to Increase FEI's Distribution Margin and Overall Natural Gas rates to the RIB Step 1 (based on 60% Efficiency for Gas)

Line			Residential 2012	Residential 2009
1	Rates			
2	BC Hydro Step 1 ($/GJ) - 60% efficiency for Natural Gas	As at July 1, Converted to $/GJ	11.906	9.950
3				
4	FEI Residential Rates ($/GJ)			
5	Residential Midstream	As at January 1	1.365	1.015
6	Residential Commodity	As at July 1, 2012 & weighted average 2009	2.977	6.103
7	Residential Delivery (excluding Riders) [1]		3.488	2.961
8	Residential Daily Basic Charge [2]	As at January 1	1.561	1.561
9				
10				
11	Volumetric Delivery Rate Needed	Line 2 - Line 5 - Line 6 - Line 8	6.00	1.27
12	Existing Volumetric Delivery Rate	Line 7	3.488	2.961
13	Increase in Delivery Rate Required	Line 11 - Line 12	2.51	(1.690)
14				
15	Approved Volumetric Residential Delivery Margin ($000s)	Line 12 x Line 19	243,776	202,820
16				
17	Throughput Required at Revised Volumetric Delivery Rate(TJ)	Line 15 / Line 11	40,611.1	159,608.0
18				
19	Existing Throughput (TJ) [3]		69,890.0	68,497.0
20	% of Existing Throughput	Line 17 / Line 19	58%	233%
21				
22	Throughput that would need to be lost (TJ)	Line 19 - Line 17	**29,278.9**	**(91,111.0)**
23	Throughput that would need to be lost (%)	1 - Line 20	**42%**	**-133%**
24				
25	Notes:			
26	[1] Delivery margin on which approved rates set			
27	[3] Calculated as approved daily basic charge of $0.389 per day x 365.25 days / avg Residential Mainland customer use rate of 91 GJs			
28	[3] FEI Rate Schedule 1 Residential Volumes as approved in 2012/2013 RRA			
29				
30	Assumptions:			
31	-No loss in customer counts or basic charges. All change was based on customer use rate decreases			

The following table shows that based on a 90% efficiency for natural gas relative to electricity, FEI's natural gas throughput would have to decrease by 53% based on 2009 natural gas and Step 1 electricity rates and by 71% based on today's natural gas and Step 1 electricity rates in order to equate natural gas rates with step 1 electricity rates.

Table 2: Throughput Decrease Required to Increase FEI's Distribution Margin and Overall Natural Gas rates to the RIB Step 1 (based on 90% Efficiency for Gas)

Line			Residential 2012	Residential 2009
1	Rates			
2	BC Hydro Step 1 ($/GJ)	As at July 1, Converted to $/GJ	17.859	14.925
3				
4	FEI Residential Rates ($/GJ)			
5	Residential Midstream	As at January 1	1.365	1.015
6	Residential Commodity	As at July 1, 2012 & weighted average 2009	2.977	6.103
7	Residential Delivery (excluding Riders) [1]		3.488	2.961
8	Residential Daily Basic Charge [2]	As at January 1	1.561	1.561
9				
10				
11	Volumetric Delivery Rate Needed	Line 2 - Line 5 - Line 6 - Line 8	$ 11.96	$ 6.25
12	Existing Volumetric Delivery Rate	Line 7	3.488	2.961
13	Increase in Delivery Rate Required	Line 11 - Line 12	8.47	3.285
14				
15	Approved Volumetric Residential Delivery Margin ($000s)	Line 12 x Line 19	243,776	202,820
16				
17	Throughput Required at Revised Volumetric Delivery Rate(TJ)	Line 15 / Line 11	20,389.9	32,473.1
18				
19	Existing Throughput (TJ) [3]		69,890.0	68,497.0
20	% of Existing Throughput	Line 17 / Line 19	29%	47%
21				
22	Throughput that would need to be lost (TJ)	Line 19 - Line 17	**49,500.1**	**36,023.9**
23	Throughput that would need to be lost (%)	1 - Line 20	**71%**	**53%**
24				
25	Notes:			
26	[1] Delivery margin on which approved rates set			
27	[3] Calculated as approved daily basic charge of $0.389 per day x 365.25 days / avg Residential Mainland customer use rate of 91 GJs			
28	[3] FEI Rate Schedule 1 Residential Volumes as approved in 2012/2013 RRA			
29				
30	Assumptions:			
31	-No loss in customer counts or basic charges. All change was based on customer use rate decreases			

Although the throughput changes that are required to achieve the delivery rate changes to achieve the requested results may appear to be large, these calculations are unrealistic. They ignore the effects of the other differences between providing for customers' thermal energy requirements using natural gas vs. electricity, such as the higher upfront capital costs of natural gas equipment and other factors that were described in detail in the response to BCUC IR 1.97.1. For instance, the $/GJ differentials that are being accommodated by assumed throughput changes (see line 13 in the tables above with $2.51/GJ and -$1.69/GJ at 60% gas efficiency, and $8.47/GJ and $3.29/GJ at 90% gas efficiency) are below the differential in rates that would be required to recover the difference in upfront capital costs and higher ongoing maintenance costs for natural gas equipment.

Commodity prices and the differential between natural gas and electricity rates are only one factor impacting the competitiveness of natural gas in BC relative to electricity. In fact, as discussed in the response to BCUC IR 1.97.1, despite the decrease in natural gas commodity costs over the last three years (the commodity rate in 2009 was 50% greater than 2012), the actual natural gas throughput for FEI has not increased. In the residential sector, which contributes the majority of FEI's delivery margin, overall throughput volumes have continued to decline, in spite of customer growth and lower rates in 2012 than in 2009. In this sector consumption and volume is price inelastic

152.1.1 Based on electricity Step 1 rate and holding all else equal for year 2012, please compute the Residential Commodity (or natural gas commodity price) if FEI's "throughput that would need to be lost (%)" are equal to: (i) 50 percent, (ii) 25 percent, (iii) 10 percent, and (iv) zero percent. Please show calculations and any assumptions in similar format as Table 1 on p. 3 of BCUC IR No. 1, Question 2.1.1.

Response:

As in the responses to BCUC IR 1.98.2 the tables provided assume thermal efficiencies of natural gas equipment relative to electric equipment of 60% and 90% in order to represent a reasonable range of older and newer gas equipment currently in use in the existing customer base.

The tables below summarize what residential commodity price would be required to equate the combined natural gas rate to the BC Hydro RIB Step 1 rate under the requested four cases of "throughput that would need to be lost (%)": (i) 50 percent, (ii) 25 percent, (iii) 10 percent, and (iv) zero percent. This analysis does not include the cost of the carbon tax of approximately $1.50/GJ which applies to natural gas and not electricity.

For the scenario in Table 1 using the Step 1 electric rate and an assumed 60% relative efficiency for natural gas, where:

(i.) 50% of the throughput is lost, a commodity rate of about $2.00/GJ would be required;

(ii.) 25% of the throughput is lost, a commodity rate of about $4.33/GJ would be required;

(iii.) 10% of the throughput is lost, a commodity rate of about $5.10/GJ would be required; and

(iv.) 0% of the throughput is lost, a commodity rate of about $5.49/GJ would be required.

Table 1: Resultant Commodity Rate for Throughput Scenarios – RIB Step 1 and 60% Efficiency

Line			Scenario (i)	Scenario (ii)	Scenario (iii)	Scenario (iv)
1	Rates					
2	BC Hydro Step 1 ($/GJ) - 60% Gas Efficiency Case	As at July 1, Converted to $/GJ	11.906	11.906	11.906	11.906
3						
4	FEI Residential Rates ($/GJ)					
5	Residential Midstream	As at January 1	1.365	1.365	1.365	1.365
6	Residential Commodity		**$ 2.004**	**$ 4.329**	**$ 5.104**	**$ 5.492**
7	Residential Delivery (excluding Riders) [1]		3.488	3.488	3.488	3.488
8	Residential Daily Basic Charge [2]	As at January 1	1.561	1.561	1.561	1.561
9						
10						
11	Volumetric Delivery Rate Needed	Line 2 - Line 5 - Line 6 - Line 8	6.98	4.65	3.88	3.49
12	Existing Volumetric Delivery Rate	Line 7	3.488	3.488	3.488	3.488
13	Increase in Delivery Rate Required	Line 11 - Line 12	3.49	1.16	0.39	0.00
14						
15	Approved Volumetric Residential Delivery Margin ($000s)	Line 12 x Line 19	243,776	243,776	243,776	243,776
16						
17	Throughput Required at Revised Volumetric Delivery Rate(TJ)	Line 15 / Line 11	34,945.0	52,417.1	62,900.2	69,890.0
18						
19	Existing Throughput (TJ) [3]		69,890.0	69,890.0	69,890.0	69,890.0
20	% of Existing Throughput	Line 17 / Line 19	50%	75%	90%	100%
21						
22	Throughput that would need to be lost (TJ)	Line 19 - Line 17	**34,945.0**	**17,472.9**	**6,989.8**	**0.0**
23	Throughput that would need to be lost (%)	1 - Line 20	**50%**	**25%**	**10%**	**0%**
24						
25	Notes:					
26	[1] Delivery margin on which approved rates set					
27	[3] Calculated as approved daily basic charge of $0.389 per day x 365.25 days / avg Residential Mainland customer use rate of 91 GJs					
28	[3] FEI Rate Schedule 1 Residential Volumes as approved in 2012/2013 RRA					
29						
30	Assumptions:					
31	-No loss in customer counts or basic charges. All change was based on customer use rate decreases					

For the scenario in Table 2 using the Step 1 electric rate and an assumed 90% relative efficiency for natural gas, where:

(i.) 50% of the throughput is lost, a commodity rate of about $7.96/GJ would be required;

(ii.) 25% of the throughput is lost, a commodity rate of about $10.28/GJ would be required;

(iii.) 10% of the throughput is lost, a commodity rate of about $11.06/GJ would be required; and

(iv.) 0% of the throughput is lost, a commodity rate of about $11.45/GJ would be required.

Table 2: Resultant Commodity Rate for Throughput Scenarios – RIB Step 1 and 90% Efficiency

Line			Scenario (i)	Scenario (ii)	Scenario (iii)	Scenario (iv)
1	Rates					
2	BC Hydro Step 1 ($/GJ)	As at July 1, Converted to $/GJ	17.859	17.859	17.859	17.859
3						
4	FEI Residential Rates ($/GJ)					
5	Residential Midstream	As at January 1	1.365	1.365	1.365	1.365
6	Residential Commodity		**$ 7.957**	**$ 10.282**	**$ 11.057**	**$ 11.445**
7	Residential Delivery (excluding Riders) [1]		3.488	3.488	3.488	3.488
8	Residential Daily Basic Charge [2]	As at January 1	1.561	1.561	1.561	1.561
9						
10						
11	Volumetric Delivery Rate Needed	Line 2 - Line 5 - Line 6 - Line 8	6.98	4.65	3.88	3.49
12	Existing Volumetric Delivery Rate	Line 7	3.488	3.488	3.488	3.488
13	Increase in Delivery Rate Required	Line 11 - Line 12	3.49	1.16	0.39	0.00
14						
15	Approved Volumetric Residential Delivery Margin ($000s)	Line 12 x Line 19	243,776	243,776	243,776	243,776
16						
17	Throughput Required at Revised Volumetric Delivery Rate(TJ)	Line 15 / Line 11	34,945.0	52,417.5	62,901.0	69,890.0
18						
19	Existing Throughput (TJ) [3]		69,890.0	69,890.0	69,890.0	69,890.0
20	% of Existing Throughput	Line 17 / Line 19	50%	75%	90%	100%
21						
22	Throughput that would need to be lost (TJ)	Line 19 - Line 17	**34,945.0**	**17,472.5**	**6,989.0**	**0.0**
23	Throughput that would need to be lost (%)	1 - Line 20	**50%**	**25%**	**10%**	**0%**
24						
25	Notes:					
26	[1] Delivery margin on which approved rates set					
27	[3] Calculated as approved daily basic charge of $0.389 per day x 365.25 days / avg Residential Mainland customer use rate of 91 GJs					
28	[3] FEI Rate Schedule 1 Residential Volumes as approved in 2012/2013 RRA					
29						
30	Assumptions:					
31	-No loss in customer counts or basic charges. All change was based on customer use rate decreases					

It should be noted that per Figure 13 found on page 22 of the Generic Cost of Capital Application, forward natural gas prices have the potential to be volatile and settle within a relatively wide envelope. For instance, Figure 13, which uses implied volatility and gas prices as of April 30, 2012, indicates that AECO/NIT prices for November 2014, will settle between about $9 CDN/GJ and $1.50 CDN/GJ using a 95% confidence interval. Furthermore, the calculated commodity prices in the tables above fall generally within this envelope of possible future gas prices.

153.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 3.2, p. 6; Question 19.1, p. 52

P/E multiples

In response to BCUC IR No.1, question 3.2, the FBCU provide P/E multiples of the TSX and Canadian Utilities Group in September 2009 and 2012. The Canadian Utilities Group multiples have risen significantly while the TSX multiples have fallen.

The graph in response to IR 19.1indicates that Utilities P/E multiples moved up to the TSX multiples in 2005 and are now significantly above the TSX.

153.1 Why do the FBCU believe this shift has occurred and is it anticipated to be a long-term phenomenon?

Response:

Mr. Engen has provided this response.

As discussed in Mr. Engen's response to BCUC IR 1.19.3, the recent rise in the utilities group's P/E ratio was primarily driven by an early, but temporary jump in Valener valuations (resulting from a sudden drop in the company's earnings in early 2011) and a sharp increase in Enbridge P/E multiples to over 50x as the market looks forward to substantial growth in Enbridge's earnings. Absent Enbridge's extraordinary P/E valuation, the group P/E ratio on September 14, 2012 (average August 14 to September 14) would be 19.6x, much closer to the group's 10-year average of 17.3x.

Overall and through the 10-year period and currently, the group has traded within a band of 15x to 20x earnings, with two notable exceptions largely driven by extraordinary Enbridge valuations. Absent Enbridge's very high trading multiples, the group continues to trade in that band today.

Mr. Engen does not expect this shift to be a long-term phenomenon.

153.2 How does FEI account for this type of shift in market sentiment in its DCF analysis? How has Ms. McShane accounted for this in her three tests? If not, why not.

Response:

As the DCF analysis uses recent dividend yields and growth forecasts, it would explicitly capture any shifts in the way investors view the particular companies to which the DCF test is being applied. While the other tests do not, due to the nature of the inputs to the tests, Ms. McShane does not consider that there has been a shift in market sentiment as regards Canadian utilities which needs to be accounted for. Please refer to the responses to BCUC IRs 2.153.1 and 2.153.4.

153.3 When was the last time such a large differential in P/E multiples occurred in Canadian Utilities favour and was it during a time of high perceived TSX risk? Please provide the data.

Response:

Mr. Engen has provided this response.

As indicated in the chart provided in response to BCUC IR 1.19.1, although there have been periods where the Canadian utilities group has had higher P/E valuations than the S&P/TSX, none have been as pronounced as the current differential.

153.4 Does it indicate that Canadian utilities are lower risk than previously thought if investors are bidding up Canadian utility stock multiples so dramatically during this past period of investment risk?

Response:

Mr. Engen has provided this response.

Recent historical P/E multiples do not suggest any difference in the risk of the Canadian utilities group. As discussed in the response to BCUC IR 2.153.1, overall and through the 10-year period ending September 2012, the group has traded within a band of 15x to 20x earnings, with two notable exceptions largely driven by extraordinary Enbridge valuations. Absent Enbridge's very high trading multiples, the group continues to trade in that band today.

154.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 4.1, pp. 8, 9

Cost of Capital for Benchmark FEI

The FBCU revised two tables in the respective Return on Equity/Capital Structure applications of 2005 and 2009. FEI also states in the response to IR 4.1 that the revised tables are not indicative of the differential that exists today given there are several applications pending and new proceedings in 2013 that will be addressing cost of capital, many of which will result in Utilities seeking increases to Equity Thickness and ROE.

154.1 The table showing the weighted Return Component on page 8 provides the title "2005 Table." Please confirm that the table shows 2012 data. Please add an additional column to indicate the date of the decision for the allowed ROE and capital structure.

Response:

The table displays the 2012 data in the same format as that presented in the 2005 application. The table has been updated to include the date of the decisions. See below:

2005 Table (2012 data in the 2005 format)

	Allowed ROE for 2012 (1)	Common Equity Ratio (2)	Weighted Return Component (1 X 2)	Date of Decision
FEI (TGI)	9.50%	40.0%	3.800%	December-09
Comparables				
ATCO Gas[1]	8.75%	39.0%	3.413%	December-11
Enbridge Gas[2]	8.39%	36.0%	3.020%	February-08
Gaz Metro[3]	8.90%	38.5%	3.427%	November-11
TransCanada Pipelines[4]	8.08%	40.0%	3.232%	November-10
Union Gas[5]	8.54%	36.0%	3.074%	January-08
AVERAGE	**8.53%**	**37.9%**	**3.233%**	
FEVI (TGVI)	**10.00%**	**40.0%**	**4.000%**	December-09
Comparables				
AltaGas[6]	8.75%	43.0%	3.763%	December-11
EGNB	10.90%	45.0%	4.905%	November-10
Gazifere[7]	8.29%	40.0%	3.316%	December-11
Heritage[8]	11.00%	45.0%	4.950%	November-11
Natural Resource Gas[9]	9.42%	40.0%	3.768%	December-10
AVERAGE	**9.67%**	**42.6%**	**4.140%**	

NOTES:
(1) - 2013 will be result of new proceeding to be announced soon
(2) PBR left "base" ROE in rates unchanged since 2007. After earnings sharing, EGD earned 10.5% from 2008 to 2011 while OEB ROE formula changed in 2009, EGD ROE remained unchanged for the 5-year term of the PBR Likely to be on new formula for 2013, has applied for 42% common equity
(3) Formula ROE; is planning on filing in November for new ROE but not public
(4) Still on old RH-2-94 formula due to settlement through 2012
(5) Similar to EGD; earned 19.9% after sharing from 2008-2011 settlement for 2013 for new ROE formula, application for 40% equity still to be decided by OEB
(6) same as ATCO
(7) formula establishing ROE and Capital structure was November 2010
(8) negotiated settlement
(9) OEB formula

154.2 Footnotes (2) and (5) indicate a higher than allowed ROE earned by the utilities, at 10.5 percent for EGD and at 10.9 percent for Union Gas. Are these allowed ROEs similar in nature to the Actual Post-ESM for FEI as indicated in the table in Response to BCUC IR 95.1?

Response:

Yes, they are similar in nature to the Actual Post – ESM for FEI indicated in response to BCUC IR 1.95.1.

154.3 The table showing the Advantage to FEI (bps) on page 9 provides the title "2009 Table." Please confirm that the table shows 2012 data.

Response:

Yes, it is 2012 data, presented in a similar format to that provided in 2009.

154.4 Do the FBCU agree that until decisions are issued with respect to applications seeking increases to equity thickness and ROE, the data in the table are indicative of the differential that exists today?

Response:

The data in the table reflect current approved ROE and Capital Structure so to that extent, they are indicative of the current existing differentials. FEI, in response to BCUC IR 1.4.1, was providing context for the data by noting that there are new cost of capital proceedings that could yield different results and that the data and comparisons in the table are not static nor reflect the current conditions affecting cost of capital.

155.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 9.1, p. 24; Question 47.5, p. 110 and Attachment 47.5c

Allowed Returns on Equity for Canadian and U.S. Utilities

The updated chart shows the trends of the respective Canadian and US utilities from 1990 to 2011. The sample of Canadian utilities is the same as that which appears on Ms. McShane's Schedule 3, page 2.

The response to IR 47.5 provides a list of allowed ROEs of the US sample companies, which shows an overall declining trend in allowed ROEs for most of the companies.

155.1 Please comment on the reasons for this declining trend.

Response:

Ms. McShane has provided this response.

Attachment 47.5c presents the allowed ROEs for the US sample companies over the period 1993 to 2012 (through June). The decline in allowed ROEs evidenced in both Attachment 47.5c and in Ms. McShane's Schedule 3, page 2 reflects the general decline in the cost of equity capital over the 20 year period.

155.2 The chart shows a kink in 2010 for Canadian utilities. Please explain the kink.

Response:

Ms. McShane has provided this response.

For 2009, the allowed ROEs of many of the Canadian utilities represented in the graph were governed by automatic adjustment formulas. Similar to the BCUC, a number of regulators reviewed their formulas during 2009 and established ROEs for 2010 which were generally higher than what the formulas would have produced. The resulting increase in allowed ROEs for 2010 compared to 2009 is reflected in the upward slope of the graph from 2009 to 2010. Some regulators, like the AUC, the NEB and the BCUC, terminated or suspended the formulas. The NEB continued to publish the results of its formula to accommodate parties who might still be subject to its results as a result of negotiated agreements (e.g., TransCanada Pipelines). Other regulators, including the OEB, the Régie and the Newfoundland and Labrador PUB retained formulas, either amended significantly (OEB) or in much the same form as previously (Régie and NL PUB). The downward slope of the line from 2010 to 2011 reflects the operation of the NEB, OEB, Régie and NL PUB formulas, which reduced allowed ROEs for TransCanada, the Ontario Electricity Distributors, Gaz Métro and Newfoundland Power respectively, due to lower forecast long-term Canada bond yields, as well as the AUC's reduction of the allowed ROE for Alberta utilities by 25 basis points from 2010 to 2011.

156.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 15.1, p. 41

Cost of Debt

In response to BCUC IR No.1, Question 15.1, Mr. Engen pointed out that two of the issuers (Enbridge and Emera) in the bond spread charts are publicly traded “holding companies” of regulated utilities and CU Inc. is a “holding company” of ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd.

156.1 Please provide a revised table of the credit ratings for the specified sample of companies and the credit ratings for their related holding companies or related regulated principal operating company, as applicable. Please ensure to include Fortis Inc. as one of the related companies. If there are multiple levels of holding companies, please include the holding companies that have outstanding market related debt.

Response:

The requested table is below:

Issuer	S&P	Moody's	DBRS
TransCanada Corporation	A-	Baa1	
TransCanada PipeLines Ltd.	A-	A3	A
NOVA Gas Transmission Ltd.	A-	A3	A
Enbridge Inc.	A-	Baa2	AL
Enbridge Pipelines Inc.	A-		A
Enbridge Gas Distribution	A-		A
Valener Inc.	BBB+		
Gaz Metro Inc.	A-		A
Gaz Metro Ltd. Partnership	A-		
Emera	BBB+		BBBH
Nova Scotia Power	BBB+		AL
ATCO Ltd	A		AL
Canadian Utilities Ltd.	A		A
CU Inc.	A		AH
Fortis Inc	A-		AL
Fortis Alberta Inc	A-	Baa1	AL
FortisBC Holdings Inc.		Baa2	BBBH
FortisBC Energy Inc		A3	A
FortisBC Energy Vancouver Island Inc.		A3	
FortisBC Inc		Baa1	AL
Maritime Electric	BBB+		
Newfoundland Power		Baa1	A

156.2 Based on the information from the revised table, are the credit ratings for holding companies lower than their related regulated operating companies?

Response:

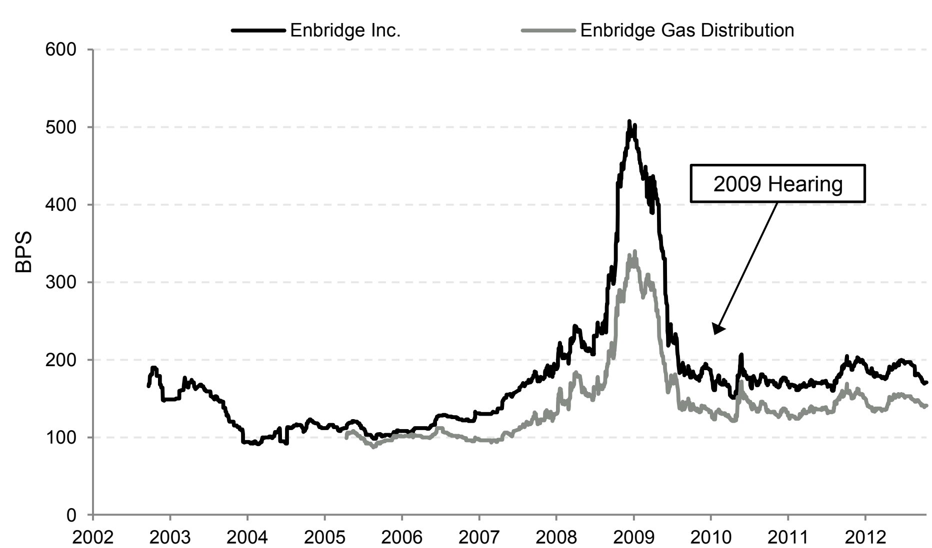
As illustrated in the table provided in response to BCUC IR 1.156.1 above, the referenced holding companies have a mix of credit ratings which are the same as or are one "notch" lower than their related Canadian regulated operating companies.

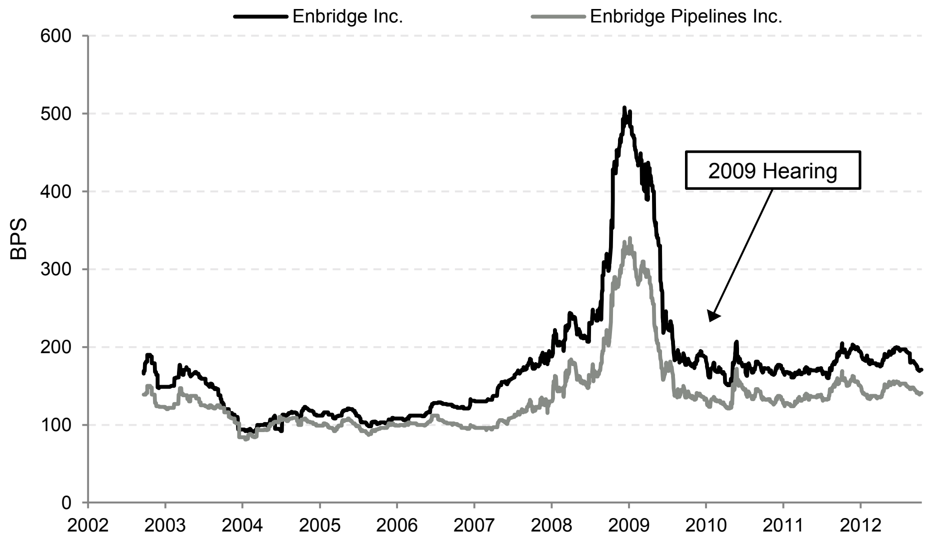
156.3 For the Canadian sample of utilities, please provide a graph of the 30-year credit spread for the holding companies and their related regulated operating companies, or holding company as applicable. Please ensure to include Fortis Inc. as one of the related companies.

Response:

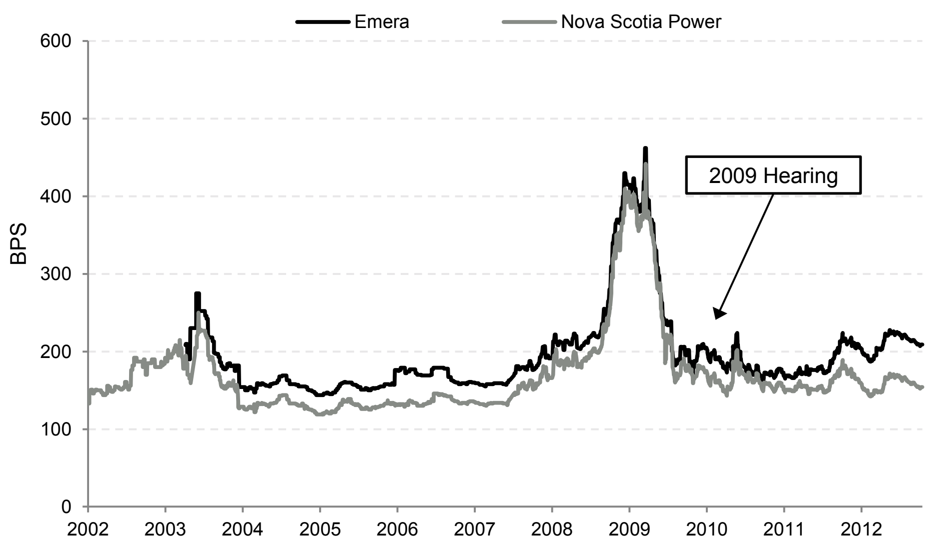
The requested charts are below:

Enbridge & Related Regulated Operating Entities

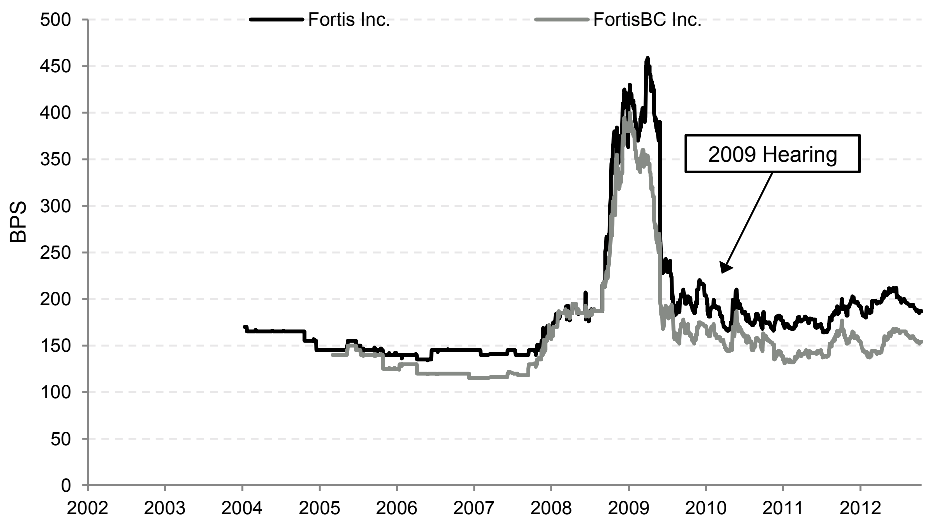


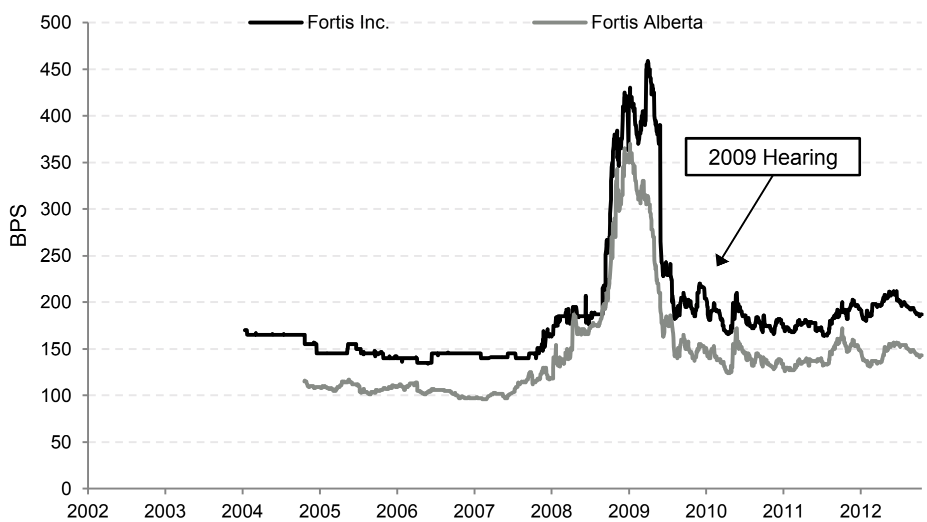


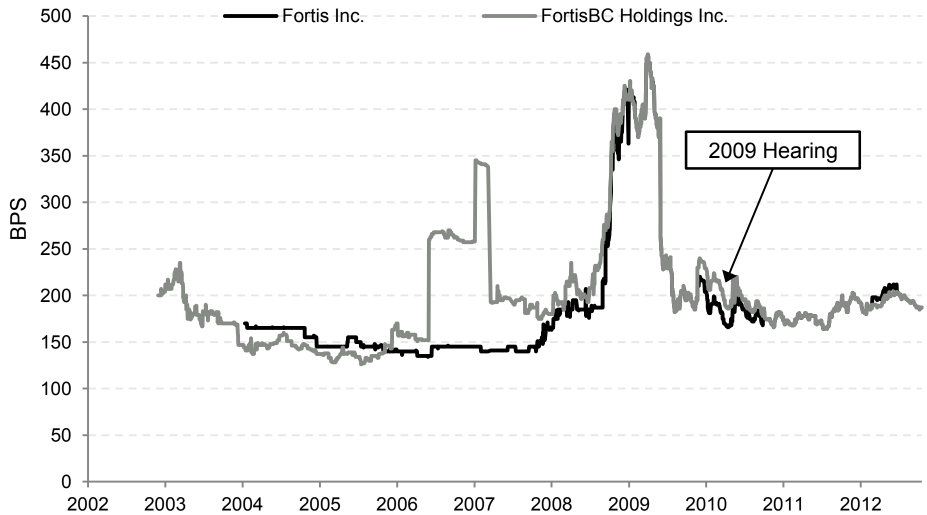
Emera & Related Regulated Operating Entities

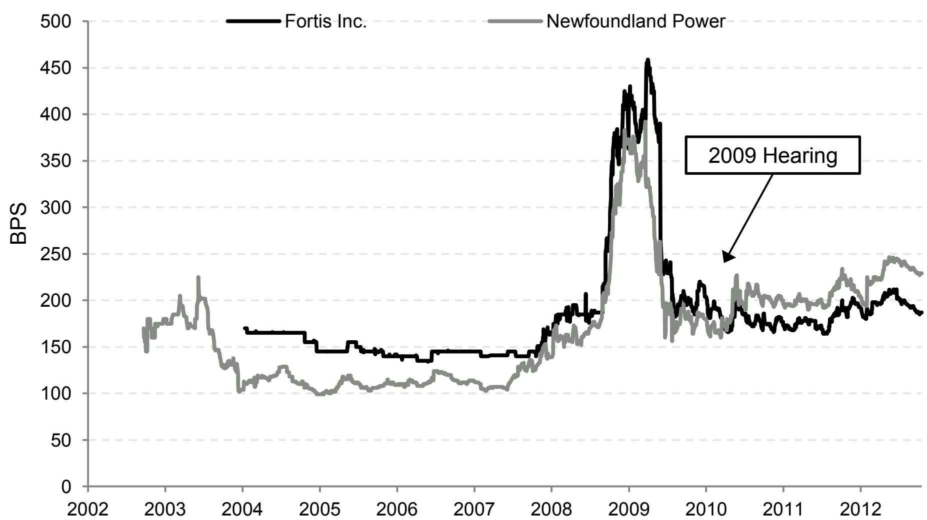


Fortis & Related Regulated Operating Entities









TransCanada, Canadian Utilities and Valener

None of TransCanada, Canadian Utilities or Valener have outstanding long-term debt so no comparisons with related regulated operating entities can be provided.

157.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 19.4, p. 55, Question 35.1.2, p. 93 P/E ratios

In response to BCUC IR No.1, Question 19.4, Mr. Engen states: "In the case of the Canadian Utilities with strong recent earnings growth and 2012-2014 consensus EPS growth forecast of over 10%, it is not possible to conclude whether the rising P/E ratio for the sector is a result of a lower cost of equity."

157.1 Please differentiate the impact of historical earnings growth versus anticipated earnings growth and their impact on the P/E ratio.

Response:

Historical earnings growth rates are interesting to the extent they help investors come to a view of future earnings growth. Anticipated earnings growth rates are more influential on P/E ratios.

157.2 Please elaborate on the difference between the absolute earnings growth rate and the change in the earnings growth rate and their associated impacts on the P/E ratio.

Response:

Good expected earnings growth (the absolute earnings growth rate) would tend to be associated with higher P/E ratios. This is the "paying up" now for future earnings Mr. Engen referred to in his response to BCUC IR 1.19.4. Where there is a material change in the earnings growth rate, it can affect P/E ratios as well. A slowing growth rate can result in a lowering of P/E ratios while a rising growth rate can have the opposite effect. Of course, this is a generalization and actual results will turn on equity capital market and sector conditions as well as company specific considerations.

157.3 Please provide the historical earnings growth percentage of the Canadian Utilities Group and the S&P/TSX for each year since 2008.

Response:

The requested information is in the following table.

EPS Growth				
Issuer	**2008A**	**2009A**	**2010A**	**2011A**
TransCanada	7.2%	(9.4%)	(3.0%)	13.2%
Enbridge	5.0%	25.0%	13.2%	11.3%
Valener	5.0%	3.9%	(3.8%)	(35.4%)
Emera	0.8%	17.3%	12.8%	0.6%
Canadian Utilities	16.8%	6.3%	2.9%	(1.0%)
Fortis	19.1%	(0.7%)	7.3%	3.7%
S&P/TSX Composite Index	13.3%	(34.6%)	26.5%	16.4%

157.4 Please provide the prior historical consensus EPS growth forecasts, and BMO's historical consensus EPS forecasts, for the Canadian Utilities Group and the S&P/TSX for each year since 2008, if available.

Response:

The requested information is in the following tables. First year growth forecasts show the percentage growth of consensus estimates over estimated EPS from the prior year, as at the dates shown in the table. Second year growth forecasts show the percentage growth of the second year's estimate over the first year's estimate, as at the dates shown in the table.

First Year EPS Growth Forecast					
Issuer	**2008E**	**2009E**	**2010E**	**2011E**	**2012E**
As at Date------->	01-Jan-08	01-Jan-09	01-Jan-10	01-Jan-11	01-Jan-12
TransCanada	7.2%	(3.1%)	4.9%	18.2%	8.4%
Enbridge	8.7%	0.5%	5.6%	6.7%	10.3%
Valener	11.4%	(4.3%)	(6.1%)	(30.5%)	--
Emera	1.0%	5.9%	3.5%	5.9%	6.5%
Canadian Utilities	(3.4%)	(5.6%)	(1.4%)	2.5%	5.6%
Fortis	16.4%	(0.1%)	10.4%	6.7%	3.7%

Second Year EPS Growth Forecast						
Issuer	**2009E**	**2010E**	**2011E**	**2012E**	**2013E**	**2014E**
As at Date------->	01-Jan-08	01-Jan-09	01-Jan-10	01-Jan-11	01-Jan-12	16-Oct-12
TransCanada	7.2%	13.0%	14.2%	6.2%	8.4%	11.7%
Enbridge	12.9%	9.9%	7.5%	9.1%	12.2%	16.0%
Valener	(1.4%)	(1.2%)	(23.8%)	1.9%	5.3%	17.2%
Emera	2.7%	5.2%	5.8%	3.4%	6.6%	6.8%
Canadian Utilities	4.8%	3.9%	6.1%	6.3%	3.9%	8.1%
Fortis	(0.4%)	7.3%	7.4%	4.6%	3.2%	3.9%

157.5 Figure 9, on page 27 of Mr. Engen's original evidence displays a pause or deceleration of earnings growth in the most recent period for Canadian corporate earnings. If the rate of change of earnings growth also affects the P/E ratio, could the effect of decelerating growth also cause a decline in the P/E ratio of the S&P/TSX?

Response:

It could, but as illustrated in Figure 8 of Mr. Engen's written evidence, the falling trend in the index's P/E ratio levelled off during the tail end of the period and was largely unaffected by the decline in the index's earnings growth in the last two quarters of the chart.

158.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 21.1, pp. 61-62

P/E Multiples

The graph indicates that FEI can borrow money significantly cheaper than Canadian Generic 'A' companies.

158.1 Does this indicate that FEI's regulatory and overall business risk is significantly less than other 'A' rated companies?

Response:

As Mr. Engen discusses in his response to BCUC IR 1.21.1, investors view rate-regulated, cost-of-service businesses as being less risky because they are regulated. The regulatory environment protects their right to reasonable opportunity to receive a fair return on and of their capital.

158.2 Why do FBCU think the spread has continued to grow?

Response:

Mr. Engen has provided this response.

More recently, the spread between Canadian utilities group (including FEI) and other 'A'-rated company credit spreads has continued to grow as investors continue to seek diversification away from financial institution dominated bond issuance in Canada. There have been relatively less energy infrastructure issuances compared to financial institution issuances. The scarcity of regulated company debt product in the market has had an important impact on the spread widening. In addition, investors are generally of the view that financial institutions, as a major portion of the other 'A'-rated companies, are more susceptible to being negatively affected by issues flowing from the European sovereign debt crisis and global economic conditions.

159.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 23.2, p. 65-66

Cross Border Issuance

The response provides a table of equity issuance.

159.1 The table lists the amount of securities "Offered Outside Canada" for a number of Canadian companies. Do these amounts represent securities that were offered both outside and within Canada at the same time?

Response:

Yes, they do.

159.2 If the amounts of securities "Offered Outside Canada" are not exclusively outside Canada, please provide detail of the amounts or proportions that were actually placed within Canada versus outside Canada?

Response:

Mr. Engen is unable to respond to the question as the requested information is not available.

160.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 25.1, p. 71

Acquisition Price to Book / Rate Base to Book Value Ratios

The response to BCUC IR No.1, Question 25.1, states that: "This, of course, ignores other tools available to the acquirer which can increase acquisition returns.

160.1 Specifically, what other tools are available to the acquirer of a regulated utility to increase acquisition returns?

Response:

As discussed at page 53 of Mr. Engen's written evidence, the following financial factors can directly increase a buyer's expected ROE derived from an acquisition:

- expected increases in allowed ROEs (generally stemming from changing economic circumstances);
- opportunities to increase the deemed equity component of the regulated asset's capital structure;
- anticipated operating efficiencies which would allow the buyer to generate earnings in excess of allowed returns;
- the ability to implement performance based regulation or other incentive fee and cost improvement sharing structures;
- the ability to deduct interest on regulated asset ownership structure debt in Canada and in the buyer's home jurisdiction (double dip interest deductibility);
- access to other, higher ROE assets or businesses which are acquired alongside the regulated assets; and
- collateral benefits (synergies) may be generated between the acquired regulated assets and assets already owned by the buyer.

161.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 28.2.1, p. 79; and Attachment 47.3, Moody's Special Comment on Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, Appendix A

Pension Fund Foreign Investment

The response to BCUC IR No.1, Question 28.2.1, states: "Again, as disclosed in [Puget Energy's] 10-K, the utility "rate making process has a delay between incurring expenses and their recovery in rate base." Mr. Engen understands there is currently a two-year regulatory cycle in Washington with the result that recent substantial capital expenditures (2011- $484 million) and expenses, which put downward pressure on the company's earnings, are not recoverable until after the following regulatory approval proceedings, at which time the company's earnings would increase."

Appendix A of Moody's Special Comment on Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities (Attachment 47.3 to the FBCU IR Response) indicates that Moody's Factor 1 (Regulatory Framework) Score for Puget Sound Energy is Baa. Moody's awards FortisBC a Regulatory Framework Score of A.

161.1 Is the existence of regulatory lag in the regulation of Puget Sound Energy a principal reason for the Baa Regulatory Framework rating for Puget Sound? If not, is it possible to outline other significant factors that would affect the rating?

<u>Response:</u>

Ms. McShane has been requested by the FBCU to respond to the BCUC IR 2.161 question set.

Ms. McShane is unable to speak for Moody's as she does not know what considerations led to its assignment of a Baa rating on this factor. Moody's acknowledges that its Regulatory Framework rating "frequently involves a subjective assessment" on its part. Ms. McShane has not analyzed Puget Sound Energy as it is not a utility in her sample, nor has she read Moody's analysis of the utility.

161.2 Is the relatively shorter duration of regulatory lag in the regulation of FEI a reason for its relatively higher Moody's Regulatory Framework than Puget Sound Energy's?

Response:

Ms. McShane has been requested by the FBCU to respond to the BCUC IR 2.161 question series.

Ms. McShane is unable to respond to this question as she does not know what factors Moody’s considered in assigning a Baa rating on regulatory framework to Puget Sound Energy, as indicated in response to BCUC IR 2.161.1.

161.2.1 Is this an example of how Canadian regulators provide better risk support to their utilities compared to U.S. regulators?

Response:

Ms. McShane has been requested by the FBCU to respond to the BCUC IR 2.161 question series.

As indicated in response to BCUC IR 2.161.1, Ms. McShane has not analyzed Puget Sound Energy. However, the question seems to presume that regulators in Canada uniformly provide meaningfully better risk support than regulators in the U.S. As noted in response to BCUC IR 1.54.2, the approach among Canadian jurisdictions is more homogenous than in the U.S. The degree of support provided by regulators in the U.S. and how it impacts total equity risk needs to be considered on a case-by-case-basis.

162.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Questions 28.2 -28.3, pp. 78-80

Cross Border Issuance, and Question 47.5, p. 110, Attachment 47.5b

Cost of Capital

The response to 28.2.1 states that achieved ROEs for Puget Sound Energy were lower than allowed ROEs in prior years, and that recent performance has been affected by "regulatory lag." With respect to the desirability of US utility investments, the response to IR 28.3 states that "Determining which is more attractive, a higher allowed ROE or a lower ROE, is a matter of expected returns. Higher allowed ROEs with greater achieved ROE variability are more attractive than lower allowed ROEs with lower achieved ROE variability if the former produces a higher expected return than the latter."

162.1 Footnote 4 refers to the weighted-average outcome as the "expected return." Is this the definition of "expected return?" Does this definition include time horizon and total holding period returns? Does this definition include the separate use of arithmetic or geometric returns?

<u>Response:</u>

Mr. Engen provides the following response.

The definition includes a time horizon but does not include total holding period returns and does not include the separate use of arithmetic or geometric returns as these concepts are not applicable.

As used by Mr. Engen, expected return refers to future potential ROE outcomes, each of which has a probability attached to it. The expected return is the weighted average of the expected ROEs and is expressed as:

$$ER = \sum_{i=1}^{n} (r_i \; x \; Prob_i)$$

Where ER = the expected return (ROE)

R_i = the estimated return (ROE) in period i

$Prob_i$ = the probability of the return (ROE) in period i

162.2 What proportion of revenues and expenses of Puget Sound Energy are covered by deferral or adjustment mechanisms?

Response:

Mr. Engen does not have the information required to be able to identify what proportion of Puget's revenues and expenses are covered by deferral or adjustment mechanisms.

Attachment 47.5b provides a table of historical achieved ROE's for the U.S. utility comparables provided by Ms. McShane.

162.3 There appears to be a number of years in which the achieved ROEs of some of the US companies have significantly fluctuated. For example, AGL Resources' achieved ROE declined from 13.0% to 6.7% during 2010-2011; Alliant Energy Corp's achieved ROE drifted from 9.0% down to negative 0.3% during 2003 – 2005, and more recently moved from 10.5% down to 4% during 2008-2009; Atmos Energy Corp's achieved ROE declined from 11.1% to 8.7% during 2003-2004; Consolidated Edison declined from 11.5% to 8.5% during 2002-2003; Integrys Energy declined from 10.5% to negative 2.4% during 2007-2009; WGL Holdings Inc. declined from 11.0% to 5.0% during 2001-2002; Xcel Energy Inc. declined from 13.3% to 6.8% during 2001-2004, with one year of a large negative ROE within that period. If possible, please provide reasons for the large fluctuations. To what extent are the fluctuations due to "regulatory lag?"

Response:

The primary reasons for the changes in ROEs referenced in the question are not a function of regulatory lag. The principal reasons for the changes are as follows:

- AGL Resources (2010 to 2011): Impact of expenses due to merger with Nicor.
- Alliant (2003 to 2005): Losses on sales of assets in 2004 and valuation charges related to unregulated foreign assets in 2005.
- Alliant (2008-2009): Close to five percentage points of the decline was due to early extinguishment of parent debt. Significantly smaller impacts of lower earnings in unregulated generation operations (lower construction activity) and utility operations, the latter due in part to unfavourable economic conditions.
- Atmos Energy (2003 to 2004): Due to 30% increase in equity raised equity to acquire TXU.

- ConEd (2002 to 2003): Impairment charges on unregulated telecommunications and generating assets.
- Integrys (2007 to 2009): The principal reason for the reduction in 2008 was the recording of a valuation adjustment related to unregulated operations. The reduction in 2009 was largely due to a goodwill impairment charge related to the gas distribution utility business, resulting from the increase in interest rates during the financial crisis. The higher interest rates (which are used to value the assets for financial statement purposes) resulted in a lower valuation for the gas distribution, leading to a write down of goodwill.
- WGL Holdings (2001 to 2002): The principal reasons were weather (2001 was significantly colder than normal and 2002 was significantly warmer than normal) and losses in the HVAC and consumer financing operations.
- Xcel Energy (2001 to 2002 and 2003 to 2004): The negative return in 2003 resulted from losses and impairment charges related to the company's investment in an independent power producer, since divested. The lower return in 2004 resulted from losses in discontinued operations, primarily a telecommunications service provider.

162.4 Please comment on the variability of the achieved ROEs of these US companies, in conjunction with the achieved ROE experience of Fortis Energy Inc.

<u>Response:</u>

The earned returns of the U.S. companies historically have exhibited more year to year volatility than the reported regulated returns of FEI, which is not unexpected, given the historical availability of mechanisms to FEI which smooth year to year return volatility and which assist to ensure that costs are allocated to the appropriate party. For many U.S. utilities, the availability of such mechanisms is a more recent phenomenon, and thus the impact will not be captured in the historical return volatility. Additionally, the probability that, in the long run, investors will not fully recover the capital which they have committed to the enterprise is not necessarily reflected in the annual volatility of returns on equity. A utility can be protected by contracts or have a regulatory framework which mitigates its short-term risks, but it will still face long-run capital recovery risks which are not captured in the year to year variability in returns. As a result, although investors may be informed by past experience, it is not necessarily an accurate predictor of the future, requiring that risk continually be evaluated on a prospective basis.

163.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 31.3, p. 84

Market Required Returns

Question 31.3 asks if the returns on equity of 10 percent that Canadian pension funds seek are being currently achieved, and whether these return targets have been reduced. The response to the question states that the return targets have remained the same.

163.1 Please clarify whether the target return stated above relates to direct equity investments or public equity investments.

Response:

As indicated in Mr. Engen's response to BCUC IR 1.31.3, the target returns he refers to are returns "respecting their interest in direct investments in/acquisitions of regulated assets" and not public equity investments.

163.2 Please provide the definition of direct equity investments and contrast this to publicly traded equity.

Response:

Mr. Engen provides the following response.

While pension funds may have different ways of defining the two types of investments, generally speaking direct equity investments refer to private investments in which pension funds acquire interests in assets or private companies or acquire interests in public companies as part of a going-private transaction. Such investments do not normally trade on exchanges and generally include real estate, mortgages, infrastructure, private equity and timberlands. On the other hand, public investments generally involve securities that trade on exchanges or over-the-counter markets and include two major types of investments: public equities and fixed income securities.

163.3 Do investors demand different returns when they enter into direct equity investments versus publicly traded equity? If they are different, please describe the reasons for this difference.

Response:

Mr. Engen provides the following response.

Investors may demand different returns for direct investments compared to publicly traded equity investments. Reasons for differentiation in required returns for direct investments may include, among others:

- company/asset control and management participation through board representation;
- access to all asset/company free cash flow; and
- lower or no mark-to-market investment valuation volatility.

163.4 What is and has been the difference in desired returns between these two types of investing, both currently and over the last 10 years?

Response:

Mr. Engen does not work with pension fund public market investment groups and consequently is not aware of their target returns for energy infrastructure public market investing and cannot, therefore, respond to the question.

163.5 What does this imply about the desired returns of publicly traded equity of energy infrastructure assets?

Response:

Mr. Engen cannot respond to this question for the reasons outlined in BCUC IR 2.163.4.

164.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 41.1, p. 100; and Attachment 47.3 Moody's Special Comment on Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities.

Acquisition Price to Book / Rate Base to Book Value Ratios

The response to BCUC IR No.1, Question 41.1, states that: "Ms. McShane is of the view that the benefits to a score card approach to comparing business risk are limited for the reasons set forth at lines 1040 to 1045 of her testimony."

Moody's Special Comment on Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, (Attachment 47.3 to the FBCU IR response), sets out in its Table 1 a ratings methodology for regulated electric and gas utilities, as shown in the table below:

Table 1 **Regulated Electric and Gas Utility Rating Methodology** KEY RATING FACTORS AND WEIGHTINGS
1. Regulatory Framework – 25%
2. Ability to Recover Costs and Earn Returns – 25%
3. Diversification – 10%
4. Financial Strength and Liquidity – 40%

164.1 Notwithstanding Ms. McShane's comments at lines 1040 to 1045 of her evidence, would she agree that the Moody's ratings methodology represents a basic scorecard approach to business risk? If not, why not?

Response:

It is a very basic scorecard for both business and financial risk, where the former is represented in three broad categories, and the weights and associated ratings reflect Moody's judgments. Moody's "grid" is intended to act as a guideline, which does not necessarily include all considerations that it considers relevant to its final rating. Moody's does not use this "grid" to map to capital structures or ROEs. Instead, capital structures and ROEs are either explicitly or implicitly inputs to the "grid".

165.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 44.1, p. 104

Business Risk

In the response to BCUC IR No.1, Question 44.1, FEI notes that following the 2010 LTRP submission it was directed to adopt an end use methodology for the next long term forecast. The intention was to be able to more accurately model changing use rates for different end uses, and then to be able to design scenarios around those end uses.

165.1 For each table in Attachment 44.1, please present it with the tables in the 2010 LTRP (Exhibit B-5, Response to BCUC IR 53.3 Attachment) and calculate the variances (volume and percent difference). Please comment on the variances.

Response:

Please see Attachment 165.1 for the requested tables showing the variances between the data filed for the 2010 Long Term Resource Plan and the 2012 GCOC.

Please note that variances exist only for the Interior region and Rate Schedule1.

During the preparation of the 2010 Long Term Resource Plan several versions and working documents were created and then combined to produce the tables and charts filed with the 2010 LTRP. While compiling data for the 2012 GCOC filing an incorrect archive version was chosen, resulting in the discrepancy. The resulting variances on the demand range from 0.06% to 0.45%.

The variances reported are not the result of any updates or recalculations of the forecast provided in the 2010 Long Term Resource Plan.

Data handling improvements are being implemented in the upcoming Long Term Resource Plan to prevent a recurrence. Long Term Resource Plan data will now be stored in a single production database system that will prevent multiple copies from being created and stored. This architecture is similar to that used by the short term forecasting system (FIS) since 2003.

165.1.1 The tables provided in attachment 44.1 appear slightly different from those in the actual 2010 LTRP. If the tables provided in Attachment 44.1 are from an update filed during the review of the 2010 LTRP, please identify the source of the update.

Response:

Please refer to the response to BCUC IR 2.165.1.

165.1.2 Please provide all of section 4 "Market Trends and Energy Forecasting" and Appendix B-3 from the 2010 LTRP.

Response:

Please refer to Attachment 165.1.2.

166.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 47.4, pp. 109-110

Cost of Capital

The response provides a table of comparable US utilities that are currently used and that have been used in the past, and the reasons for the changes. A comparison of the 2005 and 2012 proceedings samples shows that 6 of the 9 changes were made due to changes in the credit risk or business risk. A comparison of the 2009 and 2012 proceedings samples shows that 10 of the 11 changes were made due to change in the credit or business risk. All the remaining changes were made due to merger related activity.

166.1 Please confirm that the changes to the samples over 2005, 2009 and 2012 are usually due to changes in business or credit risk.

Response:

This response was provided by Ms. McShane.

With respect to the changes between 2005 and 2012, five of the nine changes were due to changes in business risk or credit risk, four of which are in the direction of lower risk in 2012 relative to 2005. The remaining changes were due to merger activity. The exclusion of New Jersey Resources from the 2012 sample reflects the introduction of a cut-off point for the percentage of regulated assets to the sample selection criteria, rather than a change in the company's risk. Had that criterion not been introduced for the selection of the 2012 sample, New Jersey Resources would have qualified for inclusion. Only one utility was excluded due to higher risk in 2012 compared to 2005.

With respect to the 2012 sample versus the 2009 sample, seven of the 11 changes were due to changes in business risk or credit risk. With respect to Dominion Resources and Duke Energy, the addition of a criterion requiring a minimum Moody's rating of Baa1 excluded those two companies. However, the companies' Moody's ratings themselves have not changed. As regards New Jersey Resources, please see the preceding paragraph. Of the changes related to changes in business or credit risk, five are in the direction of lower risk.

166.2 Please comment on the inherent survivorship bias of the samples over time and the effect on returns demanded by equity investors.

Response:

This response was provided by Ms. McShane.

Survivorship bias refers to the impact on reported performance of the exclusion of companies that have actually failed. The exclusion or inclusion of companies because they did not or did meet relatively stringent selection criteria does not constitute survivorship bias. Although the specific selection criteria restrict the companies in the sample, those that are excluded are not perforce of a materially different risk level than those which did meet very specific criteria. The differences among the risk indicators (*Value Line* betas, *Value Line* Safety Rankings, debt ratings, S&P business risk profiles) of the surviving companies (i.e., those that have not disappeared due to mergers) from the 2005, 2009 and 2012 utility samples are minor; the samples' DCF costs of equity are within 10 basis points of each other.

166.3 Does the large number of changes between the 2009 and 2012 samples indicate a higher degree of risk in the US utility industry versus Canada? If so, why does the US industry display the higher risk?

Response:

This response was provided by Ms. McShane.

No, please refer to the responses to BCUC IRs 2.166.1 and 2.166.2.

167.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 49.4, p. 115

Deferral accounts

Ms. McShane states that "Many other North American utilities have mechanisms that mitigate forecasting risk."

167.1 Please identify those US utilities that have an equivalent and greater level of deferral account support to FEI? List the deferral accounts for those US utilities and their percent impact on those utilities' revenue requirements.

Response:

Appendix B to Ms. McShane's testimony provides a list of the principal areas in which each of the companies in her sample has specific mechanisms for recovery of incurred costs in future rates. Attachment 167.1 provides a company by company summary. The documentation required to calculate the percentage of the revenue requirements that the deferral accounts comprise for the individual companies is not readily available.

168.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 52.1, p. 120

Fair ROE for FEI as Benchmark BC Utility

The response to BCUC IR No. 1, Question 52.1 states that: "When the regulatory paradigm is based on historical costs of the assets, but the allowed return represents a capital market-derived return applied to the book value of the equity, with the underlying premise for the allowed return is that the utility market value should equal book value, the resulting prices will understate the real economic costs of providing utility services and send price signals to customers that encourage overconsumption of scarce resources."

168.1 Based on the above statement, is it Ms. McShane's view that if a utility is purchased for a premium over book value, in order to reflect the 'real economic costs of providing utility services,' the new rates should be based on a rate base that includes the acquisition premium? Why? If not, why not?

Response:

Rate base treatment of acquisition premiums should be dependent on specific circumstances, and, more particularly, whether the acquisition results in economies of scale or other potential benefits. If the purchase of another utility's property is more economical than the construction of new facilities, if such plant is required, the inclusion of an acquisition premium in rate base would be appropriate.

169.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Questions 56.3 and 56.4, pp. 135-136

CAPM judgment

Ms McShane states that "It is possible that investors' recent experience in the equity markets … has coloured their outlook" and that CAPM "application is particularly problematic under current market conditions …".

169.1 How has Ms. McShane accounted for this in her 2012 CAPM analysis?

Response:

Given the generally problematic nature of surveys, as discussed in response to BC Util Cust-McShane IR 1.10.7, Ms. McShane focused on the historical market return and risk premium data, analyzed in the context of the levels of prospective inflation rates and interest rates compared to historical average levels in the application of the CAPM.

170.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 58, p.140

DCF judgment

Ms. McShane states that the DCF test results for Canadian utilities range from a high of 11.2 percent to 8.6 percent.

170.1 Isn't this range so large that it makes the DCF analysis suspect? Why or why not?

Response:

The range of the DCF costs of equity for Canadian utilities reflects the higher forecast earnings growth rates than the long-term growth in GDP. Because the earnings growth forecasts for these specific companies are higher than long-term forecast GDP growth, the constant growth model, which uses only the former, will result in higher estimated returns than the multi-stage model, which uses both. There is undeniably a wider range in the DCF estimates for the Canadian utility sample than for the U.S. sample given the wider range in the growth forecasts for the Canadian utility sample. That observation, however, does not make the DCF analysis suspect; rather it underscores the inherent imprecision of the various cost of equity models and the importance of looking to multiple models. Moreover, Ms. McShane would note that while the results of the three-stage model are similar to those for the U.S. sample, the results of the constant growth model applied to the Canadian sample are in line with the market returns that utility investors have achieved historically.

171.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 60.1, p. 143

Fair ROE for FEI as Benchmark BC Utility

The response to BCUC IR No. 1, Question 60.1 states that the CAPM "…does not focus on the fundamental risks related to the underlying real assets, and the risk that capital invested in real assets will not earn returns that could have been achieved by investing in comparable risk real assets and the risk that the capital invested in real assets will not be recovered."

171.1 To what extent is the risk that the capital invested in real assets will not be recovered a concern for utility investments that, once they have been allowed into rate base by regulators have a low probability of not continuing to earn a return, relative to investments in assets by unregulated companies?

Response:

The probability is lower than for unregulated assets which do not have regulatory protection.

171.2 Doesn't the regulatory process of issuing a CPCN or approving a utility capital spending plan mitigate this risk except for the risk of imprudent cost control by the utility?

Response:

Yes, it mitigates the risk, but does not eliminate it, as the assets are long-term and recovered over an extended period of time. Please see lines 971 to 978 of Ms. McShane's testimony.

172.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 62, p. 145-146

Arithmetic and Geometric Averages

In response to a query on the difference of standard deviations of returns of equity markets and U.S. ROE decisions, Ms. McShane states that the two standard deviations are unrelated. The preamble to the original question notes that arithmetic averages are used to compensate for high volatility.

Exhibit B1-9-6, Appendix F, pages 65 to 119 of Ms. McShane's original evidence includes the use of market based equity market risk premium tests, using arithmetic averages of returns, to arrive at an estimate for a fair ROE.

172.1 Market information appears to be used as a test to relate equity market returns to allowed book value equity returns. Please provide the reasons that the associated standard deviations of those two types of data are unrelated.

<u>Response:</u>

The allowed ROEs for utilities reflect the utility cost of equity, which, in turn, is, in part a function of the volatility in equity market returns. Similarly, the cost of equity for other industries or at the market level is partly a function of the underlying volatility in equity market returns. In other words, the volatility of actual market returns is a factor in the determination of the rate of return that investors require. Effectively, the standard deviation of actual market returns is a measure of an input to the cost of equity. All other things equal, the higher the volatility in equity market returns, the higher the cost of equity. Measuring the standard deviation of allowed returns is measuring how the "output", or the level of return equity investors require, has varied over time due to such factors as a fundamental change in the underlying volatility of returns. The appropriate comparisons are standard deviations of actual market returns of utilities and the market or costs of equity for utilities and the market, i.e., input to input or output to output, not input to output. In the case of both utilities and the market as a whole, the cost of equity is much less variable than the annual variability of actual market returns.

173.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 66.4, p. 153

Risk Adjusted Equity Market Risk Premium

The response quotes from Ms. McShane's evidence on page 93 which states: "The intercept in the equation should, in principle, represent the risk-free rate."

173.1 What factors or concerns affect the adoption of the intercept in the equation as a practical representation of the risk-free rate, rather than one "in principle?"

Response:

As stated on page A-22 to A-23 of Ms. McShane's testimony, "the theoretical CAPM posits a market security line with an intercept equal to a 'risk-free rate' and returns for risk securities proportional to their beta. Empirical studies point to a higher intercept and a flatter market security line than the theoretical model posits. In other words, a "zero beta" stock has a higher return than the risk-free rate and low (high) beta stocks have achieved higher returns than their "raw" betas imply…". The analysis conducted by Ms. McShane with respect to Canadian utilities is consistent with these findings. The analysis showed that, over the longer term, achieved utility returns were significantly higher than would have been predicted by the equation Return = Risk-Free Rate + Beta (Market Risk Premium). The extent to which the single variable (equity beta) and two variable (equity beta and bond beta) models underestimated the actual returns is captured in the difference between value of the intercept and the actual value of the risk-free rate over the period of analysis. Failure to account for the difference, i.e., the extent to which the two risk premium models underestimated actual utility returns, will result in the underestimation of expected utility returns.

173.2 What factors affect the accuracy of the intercept as an estimation of the risk-free rate?

Response:

In large part, the accuracy of the intercept as a measure of the risk-free rate depends on how closely the theoretical model and actual behavior and performance correspond, e.g., the extent to which the equity beta explains predicts returns. As discussed above, and at pages A-18 to A-25, empirical studies of the CAPM, as well as Ms. McShane's own analysis of Canadian utility stocks, indicate that low beta stocks earn returns higher than those predicted by theoretical models, i.e., consistent with an intercept above the risk-free rate.

174.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 71.1, p. 158

Risk Adjusted Equity Market Risk Premium

The response notes that Ms. McShane acknowledged that on page 111 of her testimony, that "analysts' earnings growth forecasts as a measure of investor expectations [have] been questioned by some Canadian regulators, as some studies have concluded that analysts' earnings growth forecasts are optimistic." The response then states that "…she tested this proposition with respect to the forecasts for her own sample, and found that that there was no support for this proposition."

174.1 How, specifically, did Ms. McShane test this proposition concerning the forecasts for her own sample?

Response:

Please see pages C-6 to C-9 of Ms. McShane's testimony.

Research by Bradshaw *et al*., summarized in the Investor Relations Quarterly stated that their research "… showed that sell-side analysts' forecasts and recommendations were most optimistic for firms that were issuing securities and least optimistic for firms that were repurchasing securities. We found that the observed bias is pervasive and exists in analysts' short-term earnings forecasts, long-term earnings forecasts, stock recommendations and target prices. Additionally, the impact of investment banking pressures on analyst research integrity extended to financing activities in both debt and equity securities. [Full article attached as Exhibit A2-24]

174.2 To what extent does Ms. McShane agree with the proposition that optimism bias may exist to a greater or lesser extent depending on the context and motivations of the analyst?

Response:

The question appears to be premised on the assumption that analysts' earnings forecasts are optimistic, which Ms. McShane has demonstrated does not apply to the companies in her comparable U.S. utility sample. "Context" includes the very nature of the companies for which analysts are responsible, e.g., the degree of information uncertainty. As noted at page C-7 of Ms. McShane's testimony, "Given the greater transparency of the utility business model (e.g., regulatory filing requirements) relative to some other industries, the more stable operations of utilities, and the value rather than "glamour" nature of utility shares, analyst optimism should be less of an issue with utility earnings forecasts." With respect to motivation, please see pages C-7 to C-8 of Ms. McShane's testimony, where Ms. McShane compares the consensus of analysts' growth forecasts to those of Value Line, an independent research firm with no incentive to inflate earnings forecasts, and finds no evidence that the consensus of analysts' earnings forecasts are upwardly biased.

Ms. McShane noted in her testimony that analyst optimism became a high profile issue during the irrational exuberance phase of the technology boom during the 1990s, when analysts were accused of fueling the market by exaggerating the prospects of dot.com firms. As she stated, "It was this behaviour that ultimately led to Regulation FD (Fair Disclosure) in 2000 and the Global Analyst Research Settlements of 2002 in the U.S. which removed incentives for sell-side analysts to curry favor with company management by issuing inflated earnings forecasts." (page C-6). As Ms. McShane reported at page C-6, a study conducted after the Global Settlement found that following the settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. The article cited in the preamble to the question analyzed forecasts made prior to the Global Settlement. Please also see the summary of studies at pages C-6 to C-7 of Ms. McShane's testimony which demonstrated that what might be interpreted as optimism disappears when the data are correctly interpreted.

175.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 78.1 p. 170; Flotation Costs and Financial Flexibility

175.1 Please describe the various elements of flotation cost and the relative magnitude of these costs for a typical company that issues shares in similar sizes and patterns as Fortis Inc.

Response:

The three elements of flotation costs are as follows:

(1) Out of pocket underwriting fees and other direct expenses incurred to issue shares of common equity.

The underwriting fee represents the difference between the price at which the shares are offered to investors and the price that the issuer receives. The fee is typically a percentage of the offer price; that percentage may vary based on the size of the issue. The underwriting fee for recent common equity issuances of Fortis Inc. have been 4% of the offer price. Other direct expenses include legal and filing fees. These expenses are normally listed in a prospectus as a lump sum and are fixed costs which are independent of the offering price itself. The expense per share for Fortis Inc. equity issues since 2002 has varied from approximately $0.03 to $0.43 per share and equal, on average, to approximately 0.30% of the offering price. At the BC combined federal/provincial corporate income tax rate of 25%, the after-tax out of pocket underwriting and direct expense is approximately 3.2% of the offer price ((4.0% + 0.3%)*(1 -0.25)).

There are also indirect costs of issuing equity, which relate to the time and effort required of management to undertake common share issuance, which are not explicitly accounted for.

(2) Market pressure

Market pressure refers to the impact on the share price when additional new shares are introduced into the market. Downward pressure on share prices may be the result of elastic demand for shares or asymmetrical information between investors and the company. To Ms. McShane's knowledge, there have been no recent studies published that have quantified market pressure from common share issuance. Older studies related specifically to Canadian equity issues of which Ms. McShane is aware, with a brief description of their findings, include:

A study by ScotiaMcLeod (now ScotiaCapital) of 72 issues between 1990-1993, including both marketed and bought deals, showed that, on average, market pressure of -6.75%. This study, which included issues in which ScotiaMcLeod was an underwriter, measured the market pressure as the percentage change in price from the closing price on the day prior to the date on which the market became aware of the issue (typically the announcement date) to the offering day price.

An article entitled by Lawrence Schwartz, entitled "Bought Deals: The Devil That You Know," published in the *Canadian Investment Review* in 1994, calculated the cumulative abnormal return, or market pressure, to be, on average, -8.4% for a sample of fully marketed deals based on price changes + and - 10 days around the market reaction date, or that first date that the stock was legally permitted to trade on the knowledge of the new issue. For bought deals, the same analytical technique resulted in a cumulative abnormal return of +0.01%. However, this calculation includes returns on days prior to the issue announcement. Bought deals are confidential and should not be known to the market prior to the announcement of the issuance. When the returns for the days prior to the announcement of a bought deal are excluded, the documented cumulative abnormal returns were slightly in excess of -4.0%.

A study published in 1996 in the *Canadian Investment Review*, entitled "Bad News Bearers", which compared the market pressure of seasoned issues of domestic only and inter-listed stocks. The study, which analyzed 106 issues between 1991 and 1993, calculated abnormal returns (i.e., independent of overall market movements) over a two-day period, the day prior to and the day of the issue announcement. The study documented an average decline in share price of 1.8%, with a price decline of 2.4% for domestically traded stocks and a decline of 1.0% for inter-listed stocks.

A compilation by RBC of bought deals in 1996 comparing the issue price to the prior day's closing price showed an average discount of 2.75%.

(3) <u>Market Break</u>

The "market break" component of the flotation cost allowance is intended to cover the eventuality of a sharp decline in the equity market during the offering period. Ms. McShane is not aware of any standard way of estimating this cost element. However, one approach that provides a perspective on the potential deviation between the expected offering price and the actual offering price due to external market factors is to measure the percentage change between the high price of utility share prices in one month compared to the low price of the stock in the subsequent month. The typical average month-to-month price decline (from the high price of one month to the low price of the next) for the five Canadian utilities (Canadian Utilities, Emera, Enbridge, Fortis and TransCanada) has been approximately 6.5% since 1992.

175.2 Please illustrate an example of flotation costs, including discussion of the effects of market value of equity issuance, book value of equity, returns to the investor, return on investment for the company, and accounting principles.

Response:

The table below contains an illustration of flotation costs.

Book Equity	$50,000,000
Shares Outstanding	1,000,000
Book Value Per Share	$50
Market Value Per Share	$50
(prior to issue announcement)	
Price of New Shares	$48
Number of New Shares	200,000
Gross Proceeds	$9,600,000
Underwriting Fee	$384,000
Expenses	16,000
Total Expenses	$400,000
Expense as % of gross proceeds	4.17%
Net Proceeds	$9,200,000
Net Proceeds per Share	$46
Book Equity After Sale	$59,200,000
New Shares Outstanding	1,200,000
Book Value Per Share	$49.33
Return at 10%	$5,920,000
Return per Share	$4.93
ROE to Initial Investor ($4.93/$50)	9.87%

In the example, market price per share prior to the announcement of the share issuance is $50.00, equal to the book value. The announcement of a new share issuance causes the share price to decline by $2.00 per share, i.e., equal to market pressure of 4% (1-$48/$50), or a cost to existing shareholders of 4%. The out of pocket cost to issue the new shares, comprised of the underwriting fees and other direct expenses, reduces the gross proceeds per share from the $48.00 market price to $46.00 per share net to the company. From an accounting perspective, the amounts incurred as out of pocket expenses are expensed in the year that they are incurred and the book value of common equity changes by the net proceeds, which reflects the price at which the shares were able to be sold multiplied by the number of shares sold less the direct expenses (after-tax) that were incurred to issue the shares. In the illustrative example, the combined direct expenses of issuing shares plus the impact of market pressure on the share price diluted the reported book value per share of equity. Whereas, before the announced stock issuance, the market/book value of the shares was 1.0, after the stock issuance, the market/book value of the shares is 0.97. From a return on investment perspective, assume that the required and allowed ROE are 10% (absent flotation costs). The initial investor thus requires a return of $5 per share on his invested capital ($50.00 per share). The company issues new equity under the assumptions described above; the new book value per share is $49.33, which would equate to a return of $4.93 per share at an allowed return of 10%, less than the $5 per share required by the initial investor. The initial investor would achieve a market return of 5.9% on his initial investment (($48.00 - $50.00 +$4.93)/$50.00).

175.3 Please compare and contrast the treatment of flotation related costs between equity and debt instruments.

Response:

Ms. McShane assumes that the question is referring to regulatory treatment of flotation costs. In BC, flotation costs of debt, which comprise only direct expenses of issuance (underwriting, legal and filing costs) are amortized over the term of the debt issue. Flotation costs related to common equity, which would include all three components of the flotation costs described in response to BCUC IR 2.175.1, are implicitly recovered over time through the allowed ROE.

175.4 What have been the actual equity flotation costs, expressed in dollars and percentage of offering price/amounts, in each of the last 10 years, for Fortis Inc and any predecessor entitiles that issued equity?

Response:

Although Fortis Inc. only acquired FortisBC Energy Inc. in 2007, the table below shows the underwriting fees and direct expenses for common share issuances of Fortis Inc. since 2002, including the June 2012 sale of subscription receipts. Ms. McShane has no data or studies that estimate market pressure related to these issues.

Date of Prospectus	Number of Shares to be Issued	Price to Public	Underwriters' Fee per Share	Fees as Percent of Price to Public	Net to Company	Offering Expenses	Expenses per Share	Fees & Expenses as Percent of Price to Public
20-Jun-12	18,500,000	$32.50	$1.30	4.0%	$31.20	$600,000	$0.03	4.10%
8-Jun-11	9,100,000	$33.00	$1.32	4.0%	$31.68	$600,000	$0.07	4.20%
12-Dec-08	11,700,000	$25.65	$1.03	4.0%	$24.62	$750,000	$0.06	4.25%
7-Mar-07	38,500,000	$26.00	$1.04	4.0%	$24.96	$1,250,000	$0.03	4.12%
10-Jan-07	5,170,000	$29.00	$1.16	4.0%	$27.84	$550,000	$0.11	4.37%
18-Feb-05	1,740,000	$74.65	$2.99	4.0%	$71.66	$750,000	$0.43	4.58%
29-Sep-03	6,310,000	$55.50	$2.22	4.0%	$53.28	$800,000	$0.13	4.23%
28-May-02	2,000,000	$48.85	$1.95	4.0%	$46.90	$250,000	$0.13	4.25%

Note:
1) The June 2012 Prospectus is for subscription receipts entitling holders to receive one common share of Fortis if issued prior to June 30, 2013.
2) Fortis Inc.'s stock split 4:1 in October 2005.

Kinder Morgan Inc. was the publicly-traded ultimate parent of Terasen Gas Inc. from October 2005 to May 2007. A review of the 10-Ks of Kinder Morgan Inc. does not show any common equity issuances from the date of the announced acquisition in August 2005 until the completed sale to Fortis Inc. in 2007.

The 2002 Annual Report to Shareholders of Terasen Inc. (the publicly-traded parent of Terasen Gas prior to acquisition by Kinder Morgan Inc.) indicates that it issued 5,208,000 common shares for gross proceeds of $188.3 million in March 2002, through the conversion of subscription receipts, and in December 2002, issued 7,931,600 common shares in concurrent public and private placements for gross proceeds of $301.4 million. The report references after-tax costs associated with the issuance of these shares of $13.8 million.

176.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 73.5, p. 162, DCF

Cost of Equity

In response to a query on the risk premium between holding companies and operating companies, the response states the following: "This "chain of command" flowing upward from operating company to holding company is unique to debt. In the case of equity, the chain of command flows downward, from holding company to operating company. Consequently, it does not follow that a lower credit spread for the operating company than for the holding company translates to a lower equity risk premium for the operating company than for the holding company. Whether a lower equity risk premium is warranted for an operating company is a function of the lines of business and degree of business risk diversification of the holding company vs. the operating company and the holding company leverage measured in market value terms."

176.1 Please compare and discuss the relative business risks of the holding company, Fortis Inc. and the operating company FortisBC Energy Inc. Does Ms. McShane consider one entity to have more business risk than the other? Does Ms. McShane consider the holding company to be more leveraged or have higher financial risk than FEI?

Response:

The business risks of FEI are discussed in detail at pages 48-55 of Ms. McShane's testimony. For Fortis Inc., as of the end of 2011, close to 40% of its assets related to its BC gas distribution operations, including FEI. Close to 50% of the assets related to its ownership of electric utilities are diversified across five regulatory jurisdictions in Canada (in order of size, Alberta, BC, Newfoundland, Prince Edward Island and Ontario) and the Caribbean. Except for FortisBC Inc., the electric utility operations are predominantly electricity distribution operations. The relevant factors related to the relative business risks of electric utilities generally are set out at pages 45 to 48 of Ms. McShane's testimony. Fortis Inc. also had approximately 5% of assets in each of two other segments, electric generation and properties. The former are predominantly hydroelectric generating plants, subject to long-term contracts or purchase agreements and diversified across several markets (BC, Ontario, NY). Fortis Properties' hotel and office/retail property operations are diversified among eight different Canadian provinces. With the acquisition of CH Energy, Fortis Inc.'s operations will be more diversified across regulatory jurisdictions, and the unregulated operations will account for an even smaller proportion of total operations. Given (1) the diversification of the utility operations between gas and electric; (2) the diversification of the electric utility operations across multiple regulatory jurisdictions; (3) the fact that over 60% of the electric utility operations are predominantly distribution operations; and (4) the relatively small size of the unregulated operations in comparison to Fortis Inc.'s total operations, as well as being split between two segments, each of which is itself diversified, Ms.

McShane does not view Fortis Inc.'s business risk as being measurably higher or lower than FEI's.

With respect to financial risk, comparisons are complicated by the recent switch to US GAAP from Canadian GAAP. Different rating agencies also calculate credit metrics, including debt/capital ratios, differently. Fortis Inc. is rated by S&P and DBRS, while FEI is rated by Moody's and DBRS, and DBRS only calculates Fortis Inc.'s credit metrics on a non-consolidated basis. The table below compares the most recent credit metrics as available from the debt rating agencies. Based on a credit metrics comparison, the financial risk of Fortis Inc. is slightly higher than FEI's.

	2011 Debt Rating Agency Credit Metrics			
	FEI		**Fortis Inc.**	
	Debt Ratio (%)			
Canadian GAAP	59.3	Moody's	60.0	S&P
Canadian GAAP	62.0	DBRS		
US GAAP	62.6	DBRS		
	EBIT Coverage (X)			
Canadian GAAP	2.2	DBRS	2.0	S&P
US GAAP	1.6	DBRS		
	FFO to Debt (%)			
Canadian GAAP	11.2	Moody's	11.1	S&P
Canadian GAAP	11.8	DBRS		
US GAAP	11.5	DBRS		
	FFO Interest Coverage (X)			
Canadian GAAP	2.8	Moody's	2.8	S&P
	Debt/EBITDA (X)			
Canadian GAAP	5.0	DBRS	5.7	S&P
US GAAP	5.2	DBRS		

From a cost of equity perspective, the market value capital structure ratio of Fortis Inc. is relevant, as the cost of equity is determined by reference to market data. As shown on Ms. McShane's Schedule 26, the market value common equity ratio of Fortis Inc. is approximately 48%, higher than the 40% deemed book value common equity ratio of FEI to which the allowed ROE is applied.

176.2 If we assess the relative risk of the equity of the operating company and holding company using the stand alone principle, how would this affect the "chain of command?"

Response:

This response was provided by Ms. McShane.

For purposes of the stand-alone principle, the assessment of risk would ignore the "chain of command", i.e., the equity risk premium is a function of the risks of the investment, not the happenstance of ownership. The credit spread on debt, however, does reflect a component for the chain of command, i.e., that debt issued at the holding company level is subordinate to the debt issued at the operating company level.

176.3 For illustrative purposes, please assume that there were two distinct and equal 50 percent holders of a regulated operating company's equity, of which one holder was a holding company that had its portion of the operating company equity as the sole investment, as well as some holding company level debt. The other holder was a private investor. Please discuss the relative risk of the common equity of the holding company and the common equity of the operating company held by the private investor.

Response:

This response was provided by Ms. McShane.

All other things equal, i.e., a single investment by the holding company and no illiquidity premium attached to the 50% of the equity owned by the private investor, the equity of the holding company would be riskier due to the higher leverage.

176.4 Is it possible to disentangle the effect of the three factors mentioned (lines of business, business risk diversification, and leverage) on the debt risk premium?

Response:

Please note that the reference to the lines of business, diversification and leverage in the referenced response was to the equity risk premium, not the debt risk premium. Ms. McShane is not aware of any methodology to disentangle components of the equity risk premium, positive or negative, to account specifically for diversification, lines of business and leverage.

176.5 Does Ms. McShane use credit spreads to risk adjust the cost of equity in the Comparable Earnings Test?

Response:

Yes, as in that case, there was overwhelming evidence that the equity risk of the unregulated companies was higher than that of utilities.

The response further states: "In any event, for Ms. McShane's U.S. utility sample, the reported debt ratings are the ratings for the holding company unless the holding company itself does not have a separate credit rating. As the debt ratings of the holding companies are similar to the ratings of the typical Canadian gas or electric operating utility, there is no basis to even consider an adjustment to their cost of equity."

176.6 Please provide a long term graph of long bond credit spreads for the holding companies and their related regulated operating companies of the U.S. utility sample, if available.

Response:

Ms. McShane does not have the requested data.

176.7 Do holding companies historically have a higher credit spreads/credit risk premiums than their associated operating companies in the U.S. Please explain why or why not.

Response:

Ms. McShane has not studied this question, nor does she have the data to do so. Nevertheless, to the extent that the operating companies have higher ratings than the holding companies, it would be reasonable to conclude that there are higher spreads associated with lower credit ratings.

176.8 Using the attachments provided in FBCU's evidence and responses, the following table of ratings for the US companies has been prepared. Please confirm the accuracy of the information in the table.

Publicly Traded Entity - Subsidiary if parent rating not available	Moody's Debt Rating
AGL Resources	Baa1
Alliant Energy Corp	Baa1
Atmos Energy Corp	Baa1
Consolidated Edison Inc.	Baa1
Integrys Energy Group Inc.	Baa1
Northwest Natural Gas	A3
Piedmont Natural Gas	A3
Southern Company	Baa1
Vectren Corp - Vectren Utility Holdings Inc.	No rating - A3
WGL Holdings Inc - Washington Gas Light Co.	No rating - A2
Wisconsin Energy Corp	A3
Xcel Energy Inc	Baa1
Fortis Inc. - FortisBC Holdings Inc - FortisBC Energy Inc	No rating - Baa2 - A3

Response:

The Moody's debt ratings in the table are confirmed.

177.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 75.18.1 p. 170

Flotation Costs and Financial Flexibility

The response states that financial flexibility is comprised of three components, 1) flotation costs 2) a margin for capital market conditions and 3) recognition of the fairness principle (as market values diverge from book values).

177.1 Does a newly formed company that effectively issues all its shares at equivalent market and book values require any adjustment for the fairness principle? Should a recently formed company, or new capital that has a price to book ratio of 1, earn the same book value based ROE as a mature company with a much higher price to book ratio?

Response:

Ms. McShane has provided this response.

For a new utility where the market and book value of the assets would presumably be equal, the concept of the fairness principle is less relevant in the determination of an appropriate adjustment to the "bare bones" cost of equity to arrive at the fair return on book equity. However, the 50 basis point adjustment discussed at page 118 of Ms. McShane's evidence represents only a minimum adjustment, i.e., fully warranted absent any consideration of the fairness principle. That minimum adjustment is required for all utilities, both new and mature, to permit their equity to trade at a slight premium to book value, putting them in a position to raise new equity without impairment or dilution of the existing shareholders' investment. As to whether different returns on book equity may be warranted for mature versus new utilities, on the unlikely premise that the only difference between the two is the age of the assets, they may be under certain capital market conditions. That determination would depend on the relationship between the comparable earnings test results and the cost of equity capital based on the results of market-based tests. The comparable earnings test is less relevant to new utilities, as an underlying premise of the comparable earnings test is similar vintage (similar age) of assets. On the other hand, if only the market-based tests were applied to a new utility, their proper application needs to account for the difference between the market value capital structures of the utilities used as proxies to estimate the new utility's cost of capital and the book value capital structure at which that new utility is financed. As discussed at pages 119 to 120, the latter approach supports a similar ROE to the approach which gives weight to comparable earnings, indicating similar ROEs would be applicable to mature and new utilities on the premise that the only difference is age of assets.

177.2 Does a mature company with a stable equity base and ample income retention capacity for future equity needs require much adjustment for flotation costs?

Response:

This response was provided by Ms. McShane.

The adjustment for financing flexibility is intended to permit all utilities the opportunity to raise new equity as required without impairment of their financial integrity. A utility's capacity for earnings retention should not be a relevant consideration in the estimation of the appropriate financing flexibility allowance. A utility can choose to pay out all of its earnings as dividends and subsequently raise new equity. The financing flexibility allowance should not constrain the utility's alternatives regarding retention of earnings versus paying out earnings as dividends.

177.3 Please confirm that the DCF market based test incorporates current market prices and current market expectations to derive an Investor's desired return.

Response:

This response was provided by Ms. McShane.

The DCF cost of equity represents the return that an investor expects on a prospective basis as estimated from the prevailing market price of the stock.

177.4 Does a market based test, such as DCF, provide a market based estimate of cost of capital that already includes the current investor's consideration of prior flotation costs? If not, why not?

Response:

This response was provided by Ms. McShane.

No. The prevailing price always represents more than the company will net and have to invest when it raises new equity in the market.

177.5 Why would an existing investor that bought shares in the secondary market require higher compensation for flotation costs that is implied by a market based DCF test?

Response:

This response was provided by Ms. McShane.

There is no compensation for flotation costs implied by a market based DCF test. Please refer to the response to BCUC IR 2.177.4.

177.6 Does the capital attraction element of the fair return standard require the total existing equity base to recover flotation costs over and above the DCF market based implied cost of equity? Should flotation costs be apportioned to the incremental portions of new equity capital?

Response:

Yes, as discussed at page 118 of Ms. McShane's testimony, the DCF cost of equity (as are other measures of the cost of attracting equity capital, e.g., CAPM) represents the cost rate which, if applied to and earned on book value, would equate the market value to the book value of equity. The financing flexibility adjustment needs to be applied to the entirety of equity, including existing and new equity, so that the return is sufficient to maintain financial integrity, i.e., to equate to a market/book ratio of all the equity in the range of 1.05-1.10 times.

177.7 How can the three different components of financial flexibility be fairly allocated between existing equity capital, new equity capital or internally funded equity capital?

Response:

The financing flexibility adjustment is primarily forward looking. To attempt to trace elements of the financing flexibility adjustment to specific components of the equity base would impose constraints on a utility's options for future financing as indicated in response to BCUC IR 2.177.2. It could also potentially create intergenerational inequity if such allocation burdens current rate payers with costs that are incurred for the benefit of current and future customers. Further, the concept of allocating the flotation cost elements would potentially necessitate adjusting the return for each utility differently to account for different breakdowns of existing, externally funded and internally funded equity capital will likely differ among utilities. This would be impractical.

178.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 87.1(b), p. 192, Comparable Risk Utilities

The response to BCUC IR No. 1, Question 87.1(b) states that: "As discussed in Answer 75, page 28 of his written evidence, I/B/E/S reports the analysts' EPS growth forecasts and provides the mean and standard deviation of the forecasts received for each firm."

178.1 For the firms that Dr. Vander Weide used in his DCF analysis please provide a table showing the mean and standard deviation of the forecasts for each firm.

Response:

The following table displays data on the company, the number of analysts' estimates, the mean growth forecast, the standard deviation of the forecasts, and the coefficient of variation. For a random variable such as growth, the mean forecast is the best estimate of the expected future value of the variable. The coefficient of variation ("CV") is the ratio of the standard deviation to the mean. The CV is a good way to interpret the relative magnitude of the standard deviation. As shown in the table, the CV of the growth estimates for most of Dr. Vander Weide's comparable utilities is considerably less than 1.0, a sign that the standard deviation is small relative to the mean. By comparison, the standard deviation of the estimate of the beta coefficient in a regression analysis is frequently high relative to the mean.

LINE NO.	COMPANY	NO. OF I/B/E/S ESTIMATES	EPS MEAN GROWTH	STANDARD DEVIATION	COEFFICIENT OF VARIATION
1	AGL Resources	3	3.57%	0.84%	0.24
2	Alliant Energy	2	6.35%	0.50%	0.08
3	Amer. Elec. Power	6	3.53%	1.20%	0.34
4	Atmos Energy	3	4.37%	2.10%	0.48
5	CenterPoint Energy	6	4.18%	1.37%	0.33
6	CMS Energy Corp.	6	5.96%	0.57%	0.10
7	Consol. Edison	7	3.15%	0.54%	0.17
8	Dominion Resources	4	5.40%	0.47%	0.09
9	DTE Energy	3	4.29%	0.62%	0.14
10	Duke Energy	2	3.51%	2.11%	0.60
11	FirstEnergy Corp.	4	3.15%	2.50%	0.79
12	G't Plains Energy	2	9.75%	1.06%	0.11
13	Hawaiian Elec.	3	8.03%	1.99%	0.25
14	NextEra Energy	5	5.38%	0.45%	0.08

LINE NO.	COMPANY	NO. OF I/B/E/S ESTIMATES	EPS MEAN GROWTH	STANDARD DEVIATION	COEFFICIENT OF VARIATION
15	NiSource Inc.	3	9.63%	2.84%	0.29
16	Northeast Utilities	6	6.06%	1.66%	0.27
17	Northwest Nat. Gas	2	3.25%	1.77%	0.54
18	Pepco Holdings	2	4.85%	4.46%	0.92
19	Piedmont Natural Gas	2	4.55%	0.78%	0.17
20	Pinnacle West Capital	6	6.22%	1.51%	0.24
21	PNM Resources	2	9.25%	6.01%	0.65
22	Portland General	6	4.13%	1.31%	0.32
23	Public Serv. Enterprise	3	3.60%	3.40%	0.94
24	SCANA Corp.	3	4.63%	0.32%	0.07
25	Sempra Energy	2	7.05%	0.07%	0.01
26	Southern Co.	7	5.58%	0.70%	0.12
27	TECO Energy	7	4.11%	2.00%	0.49
28	Vectren Corp.	2	5.00%	0.00%	0.00
29	Westar Energy	4	5.80%	1.78%	0.31
30	WGL Holdings Inc.	3	4.60%	0.78%	0.17
31	Wisconsin Energy	4	5.35%	1.20%	0.22
32	Xcel Energy Inc.	9	5.27%	0.67%	0.13

179.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 88.3, p. 195

Comparable Risk Utilities

The response to BCUC IR No. 1, Question 88.3 states that: "In recent years, Dr. Vander Weide has also recognized that the average Value Line utility beta frequently understates the beta derived from the historical risk premium ratio calculated as shown in Exhibit 14."

179.1 Please elaborate on the reasons for Dr. Vander Weide's recognition that the average Value Line utility beta frequently understates the beta derived from the historical risk premium ratio. Does Dr. Vander Weide mean that it is a recognized fact that he adopts or that in his opinion the Value Line Beta understates the beta?

Response:

a) Dr. Vander Weide has recognized that the average Value Line utility beta frequently understates the beta derived from the historical risk premium ratio by periodically comparing the average Value Line utility beta to the historical risk premium ratio using the data sets on historical risk premiums for utility stocks and the market index shown in Dr. Vander Weide's pre-filed evidence (Exhibit 14 and Exhibit 15).

b) Dr. Vander Weide means that his statement, "the average Value Line utility beta frequently understates the beta derived from the historical risk premium ratio," is an observable fact. He does not know how widely this fact is recognized, but he does know that his evidence regarding the magnitude of the historical risk premium ratio compared to the Value Line beta is consistent with one or both of two conclusions: (1) the Value Line beta understates the long-run risk of investing in utility stocks; and/or (2) the CAPM is unable to predict the returns on utility stocks. In either case, cost of equity estimates based on the application of the CAPM using Value Line betas or lower betas likely underestimate a utility's cost of equity.

179.2 Why does Dr. Vander Weide believe it to be the case that the average Value Line utility beta frequently understates the beta derived from the historical risk premium ratio as he calculates it, as opposed to the alternative hypothesis that the historical risk premium overstates the beta relative to the Value Line beta.

Response:

The statement, "the average Value Line utility beta frequently understates the beta derived from the historical risk premium ratio" is not a hypothesis; it is a fact. Please see response to 179.1 (b). In addition, Dr. Vander Weide does not accept the "hypothesis" suggested in the question that "the historical risk premium [ratio] overstates the beta" because the short-run betas estimated by Value Line are subject to considerable uncertainty. For example, Ms. McShane presents evidence that betas calculated using five-years of weekly data are highly unstable (*see* McShane Schedule 14).

180.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 4.1, p. 9, and Question 90.1, p. 198

Allowed Canadian Utility ROEs and Common Equity Ratios

The response to BCUC IR No.1, Question 4, provides a table of 2009 allowed ROEs and common equity ratios. The response to question 90.1 provides current data.

180.1 Please explain why FBCU consider FEI to be higher risk than Enbridge Gas or Union Gas?

Response:

In response to BCUC IR 1.90.1, Dr. Vander Weide presents allowed equity ratios and allowed ROEs for Canadian utilities (as was requested by BCUC IR 1.90.1). In his evidence and the response to BCUC IR 1.90.1, Dr. Vander Weide was providing a comparison of the allowed ROE and Capital Structure and was not providing a comparison of the relative risk of FEI to any of the companies listed.

In general, BC's energy environment is different than that of Ontario and as such the FBCU believe that natural gas utilities in BC face higher business risk than Enbridge and Union Gas in Ontario. In particular, the jurisdictional differences are evident from lower market share of natural gas versus electricity in BC (Appendix H, section 3, page 11), lower operating cost advantage between natural gas and electricity in BC (Appendix H, section 5, page 20), the greater market shift of new housing developments for multiple dwellings in BC (Appendix H, section 6, page 30), and more aggressive energy policies (i.e. carbon tax) in BC.

180.2 Have Enbridge Gas, Union Gas or FEI faced any difficulties in accessing debt markets in the past 10 years as a result of their common equity ratios? If yes, please provide a list of examples.

Response:

FEI in the last 10 years has not had a failed transaction, as FEI monitors market activity to ensure that the transaction does not fail. As such, the fact that no specific transactions have failed is thus not suggestive that markets are always accessible.

Mr. Engen indicates that the question cannot be responded to in respect of Enbridge and Union Gas since information regarding whether and to what extent issuers may have had difficulties in accessing debt capital markets is non-public, confidential information.

180.3 Did FEI pay significantly higher premiums to acquire long term debt compared to Enbridge Gas or Union Gas in the past 10 years? If so, please provide a list of examples.

Response:

Mr. Engen provides the following response.

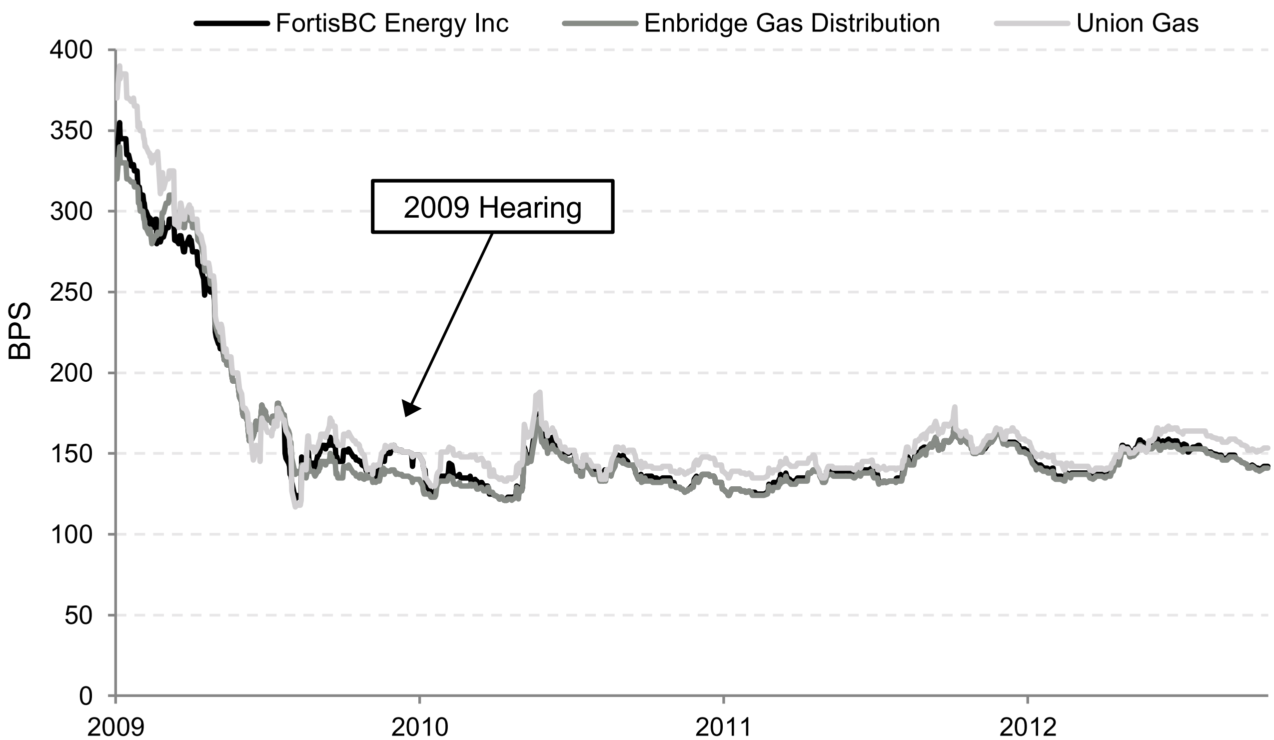
The following table summarizes the long-term debt offerings over the past 10 years by FEI, Enbridge Gas Distribution, and Union Gas. Given the differences in offering sizes, tenors, and issue dates, no conclusions can be drawn regarding whether FEI pays higher premiums relative to Enbridge Gas or Union Gas to raise long-term debt.

	Issue	Offering Size (millions)	Tenor (Years)	Spread (bps)
EGD	06-Sep-11	$100	40	165
	17-Nov-10	$200	40	126
	21-Feb-06	$300	30	100
	11-Dec-03	$150	30	88
Union Gas	16-Jun-11	$300	30	147
	20-Jul-10	$250	30	148
	26-Aug-08	$300	30	200
	06-Sep-06	$165	30	118
FEI	01-Dec-11	$100	30	160
	19-Feb-09	$100	30	285
	08-May-08	$250	30	163
	07-Feb-08	$250	30	183
	27-Sep-07	$250	30	148
	20-Sep-06	$120	30	136
	22-Feb-05	$150	30	118
	26-Apr-04	$150	30	127

180.4 Please provide a comparison table showing FEI, Enbridge Gas and Union Gas credit spreads in the long term debt markets since 2009.

Response:

Given the amount of data required to respond to the question, the response is provided in chart form. The chart is below:



181.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 93.1.1, p. 204

Comparable Risk Utilities

The response to BCUC IR No. 1, Question 93.1.1 states that Concentric selected its gas and electric utility proxy groups based upon screening criteria, to assemble a group of like risk companies and sets out its screening criteria in the six points following. The response also states that Concentric also examined the relative risk profiles of the Ontario and proxy group utilities on a variety of operating and financial performance metrics, to assess the relative risk profiles of the groups compared to that of the subject company.

181.1 Can Concentric elaborate on the reasons for deciding that these criteria were the important criteria to be used for screening the proxy group companies?

Response:

The six criteria employed to screen the proxy group companies are commonly employed by Concentric in cost of capital analyses. Because publicly traded utility holding companies are generally comprised of a group of companies, the criteria for selecting proxy group companies at the holding company level is necessarily broad. From this group it is possible to develop ROE estimates based on the combined risk profile of the proxy group. Then the relative risk assessment is a more granular analysis which compares the risk profiles of the companies in the proxy group to that of the subject company to determine whether a risk adjustment for the subject company is warranted. The six screening criteria that were listed in the referenced IR response are listed below with a brief explanation of why Concentric considered these criteria to be relevant for screening the proxy group companies.

1. **Value Line Universe of Public Utilities -** To obtain a market derived ROE estimate, it is necessary to use proxy companies with shares that are publicly traded in the stock market. Both the CAPM and the DCF method of cost of capital determination rely on market derived inputs. Value Line is an independent equity research firm that provides coverage for most publicly-held North American energy utilities. We begin with this universe of utilities.

2. **Publicly Traded and Pay Dividends** - The requirements that proxy companies are publicly-traded and pay dividends are requirements for performing the cost of capital analyses using the DCF and CAPM methodologies.

3. **Credit Rating Screen** - The ratings agencies evaluate the risk of credit default for each company that they rate. This rating may provide an indication of the risk profile of the company, even though it is focused on default risk (or the risk of loss to debt holders) and not on the risks to equity holders.

4. **Percent Regulated Operations** – This screen is performed in an effort to find as close to a "pure-play" regulated utility as possible for inclusion in the proxy group, but still have enough companies to populate a proxy group. We use this screen and set the threshold such that both objectives are accomplished.

5. **Percent Revenue Derived from Natural Gas or Electricity Distribution** – Similar to 4 above, this screen is performed in an effort to find as close to a "pure-play" gas utility or electric utility (as the case may be) as possible for inclusion in the proxy group. We differentiate gas and electric utilities in recognition that gas utilities and electric utilities may have different business risk profiles.

6. **Acquisition or Merger** – This screen is performed to protect the integrity of the market derived data, and remove from consideration influences on the companies' dividend yields or growth rates that are not intrinsic to the company.

182.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 96.1.1, p. 219

Deferral account impact on 2011 revenue requirement

The table identifies that 75.3 percent of FEIs revenue requirement is protected by deferral accounts.

182.1 Please provide the actual and approved operations and maintenance expenses (line 2) for the past 10 years.

Response:

Please refer to the table below which provides the actual and approved net O&M expenses (gross O&M net of capitalized overhead) for the years 2002 through 2011. Please note that the approved gross O&M for the years 2004 through 2009 was determined based on the formula as outlined in the PBR agreement(s).

FEI	Actual O&M ($000s)	Approved O&M ($000s)	Variance ($000s)	Variance (%)
2011	$ 183,551	$ 184,625	$ (1,074)	-0.58%
2010	$ 177,614	$ 177,559	$ 55	0.03%
2009	$ 162,026	$ 173,138	$ (11,112)	-6.42%
2008	$ 156,208	$ 169,802	$ (13,594)	-8.01%
2007	$ 149,564	$ 169,272	$ (19,708)	-11.64%
2006	$ 150,223	$ 167,091	$ (16,868)	-10.10%
2005	$ 142,710	$ 161,729	$ (19,019)	-11.76%
2004	$ 153,497	$ 159,417	$ (5,920)	-3.71%
2003	$ 140,963	$ 149,294	$ (8,331)	-5.58%
2002 [1]	$ 142,110	N/A		

[1] Revenue Requirement for 2002 was withdrawn

* Amounts shown are net O&M amounts after the allocation of capitalized overhead

182.2 Given that the majority of utilities use straight line depreciation for its assets in service, isn't depreciation and amortization expense (line 4) largely a known cost for each year?

Response:

FEI agrees that depreciation rates are known as they are set through the revenue requirement process and, as per Table 3 of the response to BCUC IR 1.96.1.1, amortization expense is known as actual amortization of the deferrals is set to equal the approved amount. However, actual depreciation expense can differ from the approved depreciation expense due to variances in the amount of capital expenditures, the timing of capital expenditures and differences in the asset mix and allocation between the individual asset categories from forecast.

FEI also notes that it was directed to implement a Depreciation Variance deferral through BCUC Order No. G-44-12 as part of the 2012-2013 FEU Revenue Requirements Application and that this deferral serves to eliminate the depreciation variances that result from all variances from forecast. Therefore, for the 2012-2013 revenue requirements period only, FEI would assess the Depreciation & Amortization Expenses category as low risk based on deferral account coverage.

182.3 Doesn't the BCUC CPCN treatment which allow those projects to enter rate base the year after its completion help to ensure that the forecast depreciation and amortization expense do not vary significantly from forecast?

Response:

To clarify, FEI does not currently follow the CPCN treatment as described above. As approved through BCUC Order G-141-09, CPCN assets are placed into rate base at the time the assets are expected to be available for use, rather than the following year. Consequently, FEI was at risk for depreciation variances as a result of timing differences between the actual and forecasted CPCN in-service dates for the years 2010 and 2011. As noted in the response to BCUC IR 2.182.2, the Depreciation Variance deferral account in place for the 2012-2013 revenue requirement period serves to eliminate any depreciation variances caused by timing of in-service dates in 2012 and 2013, including the CPCN projects that were included in the 2012 and 2013 revenue requirements.

Prior to 2010, FEI CPCN projects entered rate base the year following completion which did help mitigate the variance of depreciation expense from forecast. However, CPCN projects are only one component of the additions to rate base in any given year and as such the variance between forecast and actual depreciation and amortization expense was not eliminated by this treatment.

While the risk assessment based on the percentage of the category covered by deferral accounts as defined in the response to BCUC IR 1.96.1.1 varies between the years leading up to and including 2011 (classified as "high" because no deferral accounts are in place) as compared to 2012 and 2013 (which would be classified as "low" due to the new deferral account), FEI has not experienced a marked difference in the overall risk associated with depreciation and amortization expense due to the nature of the expense as well as the CPCN treatment as described above.

182.4 Please provide the aggregate actual and approved depreciation and amortization expenses for the last 10 years. For any variances greater than 3 percent in any year, please explain the variances.

Response:

The requested table is provided below. The variances from 2004 through 2009, which are greater than +/- 3 percent, were all the result of FEI using a formula-based approach for capital expenditures and additions under the PBR agreement(s). That is, the actual capital expenditures were less than the approved amounts under the formula-based approach and, as a result, actual depreciation expense was lower than the approved depreciation expense in each year. To clarify, the variance between the actual and approved depreciation expense for each of the years under a PBR agreement (2004-2009) was shared equally with and distributed to customers by way of the earnings sharing mechanism.

FEI	Actual Depreciation and Amortization Expense ($000s)	Approved Depreciation and Amortization Expense ($000s)	Variance ($000s)	Variance (%)
2011 [1]	$ 98,420	$ 99,878	$ (1,458)	-1.46%
2010 [1]	$ 97,158	$ 96,931	$ 227	0.23%
2009	$ 79,670	$ 89,685	$ (10,015)	-11.17%
2008	$ 74,876	$ 84,110	$ (9,234)	-10.98%
2007	$ 75,261	$ 84,771	$ (9,510)	-11.22%
2006	$ 80,466	$ 83,894	$ (3,428)	-4.09%
2005	$ 76,176	$ 79,720	$ (3,544)	-4.45%
2004	$ 77,233	$ 78,885	$ (1,652)	-2.09%
2003	$ 72,391	$ 73,076	$ (685)	-0.94%
2002 [2]	$ 72,616	N/A	N/A	N/A

[1] Includes removal provision in 2010 and 2011

[2] Revenue Requirement for 2002 was withdrawn

182.5 Please confirm that the changes in income tax rates (line 6) are trued up through the use of deferral account mechanism.

Response:

Confirmed. The impacts from changes in income tax rates are captured in the Income Tax Variance Deferral Account, as noted in footnote 8 to the table in BCUC IR 1.96.1.1. For columns 4 through 7, on a forecast basis, there is no rationale for allocating a percentage of revenue requirements covered by deferral to this account, since no income tax rate changes can be forecast.

182.6 Please confirm that in years when FEI was under PBR that 50 percent of variances in ROE (line 9) were covered by revenue sharing. Does FEI anticipate returning to PBR if amalgamation is approved?

Response:

In years when FEI was under a PBR agreement, 50 percent of the variances between the approved and actual pre-earnings sharing ROE percentage (not dollar) returns were shared equally between customers and the shareholder.

Please refer to BCUtilCust-FBCU IR 1.2.1 which demonstrates that the variance in the actual pre-earnings sharing ROE percentage return was shared equally between the customer and the shareholder over the term of the PBR(s).

As discussed in BCUC IR 1.1.2, FEI would not be opposed to returning to regulatory review under PBR. This statement also remains true for the FEU if amalgamation is approved.

182.7 The table on page 212 indicates that FEI over earned its approved ROE in every year except 2010, when it only slightly missed its approved ROE. Wouldn't one expect that FEI should have under earned its approved ROEs over time by about as much and as often as it over earned?

Response:

FEI assumes that the reference to the table on page 212 is in reference to the table provided in the response to BCUC IR 1.95.1.

FEI does not agree with the proposition stated in the question as it relates to the period covered by the table.

Firstly, FEI was under a PBR arrangement for the majority of the years shown in the response to BCUC IR 1.95.1. The PBR agreement was designed to incent the Company to achieve savings that were shared equally with customers, thus resulting in an expectation for higher than allowed return on equity for those years.

Secondly, and in the absence of a PBR agreement, FEI does not believe it is reasonable to expect the company to have under earned as often as it has over earned. FEI forecasts its annual revenue requirements based on its anticipated capital spending, O&M costs, and other cost of service and rate base expectations. During the test period, FEI attempts to manage its operations and capital expenditures within the approved revenue requirement amounts and therefore would not expect that the amount of overearning would be symmetrical to underearning.

Regardless of the historic results, in each test period, the utility faces risk in implementing the activities required to provide services to customers within its approved revenue requirements.

183.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 96.1.1, p. 220

Depreciation and Amortization Risk

In Table 3 on page 220, FEI states that there is a high overall risk assessment for depreciation and amortization expenses since 0 percent of this category is covered by deferral accounts in 2011.

183.1 Please explain why the risk assessment is high when you consider that: (i) Table 3 indicates that the actual amortization of deferrals is set to the approved amounts which results in no variance between forecast and actual amortization, and (ii) variances between forecast and actual depreciation expenses have a short term impact since rate base is trued up at the beginning of each test period (FEU Reply Argument p. 29, FEU 2012-2013 Revenue Requirements Application).

Response:

As outlined in the response to BCUC IR 1.96.1.1, FEI has evaluated the risk of each component based on the percentage of the category covered by a deferral account in 2011. As note 7 to Table 1 in the response to BCUC IR 1.96.1.1 indicated, amortization expense is reflective of previous years and thus is not applicable to the analysis, and no deferral for depreciation expense variances existed in 2011. Therefore, since no percentage of amortization or depreciation expense was covered by a deferral account in 2011, the category was rated as high. Please refer to BCUC IR 2.182.2 for a discussion on the risk assessment that FEI would apply to the 2012 and 2013 revenue requirement period for the depreciation and amortization category. As it pertains to 2011, while variances between forecasted and actual depreciation expenses may have a short-term impact in that rate base variances will not persist from one revenue requirement period to the next, this does not eliminate the potential for variances within the revenue requirement period due to the reasons discussed in BCUC IR 2.182.2.

Please also refer to the response to BCUC IR 2.182.3 for a discussion on the overall risk associated with depreciation expense.

184.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 108.1, pp. 255-258

Market Shifts – Changes in Energy Use – Higher Risk Status since 2009

In response to BCUC IR No. 1 Question 108.1, the FBCU indicate that making it more difficult to attach customers is problematic and counterproductive. The FBCU state: "The current main extension test (MX Test) does not result in a subsidy to low use residential customers. The current MX Test sends economic signals to residential customers that are choosing to add a small number of low demand natural gas appliances as these customers are more likely to have to provide a contribution in aid of construction (CIAC) than the same customers choosing to add a larger number of relatively high demand natural gas appliances. For example, a builder/developer that only added natural gas fireplaces to dwellings in her project would be more likely to pay a CIAC than if she added natural gas heat and hot water appliances."

184.1 Please clarify whether the CIAC is a mechanism to mitigate risk when FEI is facing declining annual use rates from its new and existing customers.

Response:

The FBCU does not think of the CIAC as a risk mitigation mechanism to address the trend of declining use per customer. The contribution in and of itself does not impact the usage trend over time by either new or existing customers. The CIAC is more appropriately viewed as a cost allocation mechanism to address the differences for new customers relative to existing customers coming onto the system.

By definition, the CIAC is as follows:

"If the economic test results in a negative net present value, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by the Customers to be served by the main extension, their agents or other parties, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission."

184.2 Please discuss the merits of implementing tighter CIAC policies for developers (e.g. partial/fully refundable contributions) to account for market shifts risk and low customer use rates.

Response:

As stated in the response to BCUC IR 1.108.1, simply implementing tighter CIAC policies would be "…counterproductive for customers as it would result in more customers needing to provide a CIAC and likely choosing not to use natural gas thereby putting upward pressure on rates and creating potential equity issues among groups of customers." However, the Company believes there is merit to monitor and, if appropriate, conduct a review of the MX Test, the related consumption inputs and the PI thresholds.

As shown in the figures provided in the response to BCUC IR 1.108.1, the average use per customer has clearly dropped compared to our existing customer base. Currently, the average use per appliance the Company uses in the MX Test is based on the 2008 Residential End Use Study (REUS), the most up to date customer data at our disposal. From the REUS, the Company has historically used the average use per customer of its existing customer base in MX Tests, not the average use of new customers. The Company will be producing the next Residential End Use Study (REUS) in mid-2013 for use in the 2014 average use per appliance inputs. It is expected that this report will provide greater insights into the average use per appliance of new and existing customers.

The Company has agreed with Commission staff to review, as needed, any relevant outcomes of monitoring the MX Test, consumption inputs and PI thresholds.

On page 258, the FBCU state that "Simply making the MX Test more stringent by raising the PI threshold would be counterproductive for customers as it would result in more customers needing to provide a CIAC and likely choosing not to use natural gas thereby putting upward pressure on rates and creating potential equity issues among groups of customers."

184.3 Do the FBCU agree that attaching low use customers would also put upward pressure on rates if main extension costs exceed revenue? If not, please explain why not.

Response:

Under the current MX test approved by the Commission, low use customers would not put upward pressure on rates because all projects the Company undertakes must have a PI greater than or equal to 0.8 in order to proceed. Those projects with a PI less than 0.8 must provide a contribution in aid of construction (CIAC) in order to proceed and, in aggregate, the portfolio must have a PI greater than or equal to 1.1.

As discussed in the response to BCUC IR 1.108.1, the current MX test sends signals to ensure that low use customers choosing to add a small number of low demand natural gas appliances are more likely to have to provide a CIAC than the same customer choosing to add a larger number of relatively high demand natural gas appliances.

185.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 111.1, p. 264

Benchmark Utility

185.1 Please describe the considerations used in determining a benchmark utility, presented by Ms. McShane in the 2010 Enbridge Gas New Brunswick cost of capital proceedings.

Response:

As Enbridge Gas New Brunswick (EGNB) was a developing or immature utility with no directly comparable proxy companies with publicly-traded shares, its cost of equity was estimated by first estimating the cost of equity for a benchmark, or average risk, mature Canadian distribution utility. The estimation of that cost relied in part on cost of equity estimates for a sample of U.S. gas and electric distribution utilities that were relatively pure-play, had strong debt ratings, consistent dividend payment history and had a consistent equity analyst following.

186.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 140.0, pp. 333-334

Debt Related Matters

In response to BCUC IR No.1, Question 140.1, the FCBU provide an example of a separate class of service within a larger regulated utility and state that: "TES projects, such as Delta School District and Tsawwassen Springs, depending on outcome of AES Inquiry, may be projects within a separate class of service of FEI, although they currently reside in FAES."

186.1 For regulated TES projects residing in FAES, would the FBCU still describe them as separate class of service within a larger regulated utility? If not, how would the FBCU describe them?

Response:

No. Classes of service relate to different services being provided by a single corporate entity. FAES is a different company than FEI and offers only one class of service: the thermal energy class of service, in which different projects reside.

186.2 Hypothetically, if regulated TES projects were to remain in FAES in the future, do the FBCU agree that deemed debt would also be appropriate for these regulated TES projects? Why or why not?

Response:

The FBCU believe that currently the TES projects are not of sufficient size, nor does FAES contain a sufficient number of mature TES projects in the aggregate, for FAES to efficiently source debt from a third party on behalf of the individual TES projects. Until then, it is more appropriate that debt be sourced by the FBCU at a deemed cost to the TES projects.

In response to BCUC IR No.1, Question 140.1, the FCBU cite Fort Nelson and FEW as cases where deemed debt makes the most sense.

186.3 Please confirm that "Option 1 – Assign a credit rating" could also be used to determine the deemed interest rate for Fort Nelson and FEW. If not, why not?

Response:

Yes, a deemed interest rate based on an assigned credit rating could also be applied to Fort Nelson.

With respect to FEW, its debt is provided by FHI, with the rate reflecting an assumed BBB rating, as approved by the Commission.

In response to BCUC IR No.1, Question 140.2.1, the FCBU state that: "The factors in assessing whether the Utility would be able to raise the requisite debt in a cost efficient manner at the desired terms will include financial metrics such as asset base or enterprise value, which are typically used to assess size."

186.4 Please explain how the FBCU would apply this evaluation approach to the following TES projects: 1) Delta School District; 2) Tsawwassen Springs; and 3) Marine Gateway.

Response:

The FBCU would primarily consider the size of the project and the required amount of debt in determining the efficiency of issuing third party debt. For the projects in question, which have debt requirements all under $5 million, based on the judgement of FBCU, it is relatively clear that it would be less efficient to attempt to obtain third party financing than to utilize financing from its parent company at a deemed interest rate.

187.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 141.5.2, p. 339; Question 141.12, p.345

Deemed Interest Rate

On page 339, the FBCU indicates that "subjectivity can be reduced by first attempting to identify proxy companies that are engaged in similar industries or lines of business."

187.1 Please identify which proxy companies are engaged in the utility industry and which are engaged in similar industries?

Response:

The reference to proxy companies in response to BCUC IR 1.141.5.2 is in respect of companies that are also public issuers of debt and have similar attributes to that of a subject entity. The response was not meant to outline a universe of proxy companies. Any company in the utility industry in Canada that issues public debt might be considered a proxy company to the subject entity. For example, deemed interest rates in the Tswwassen Springs and Delta School's TES projects have been derived from BBB utility issuers, Altagas Ltd. and Emera Inc.

On pate 345, the FBCU state that "if there were a 20-year contract, then the appropriate deemed term should be 20 years"…and "the FBCU believe that the deemed cost rate should remain unchanged for the deemed term of the debt."

187.2 Please comment on whether the deemed term and deemed cost rate should change if capital injections, such as for sustaining capital / capital replacements, are required during the term of the contracts.

Response:

The bulk of costs for the alternative energy projects are upfront costs. The sustaining capital costs over the term of the contract should be small in comparison. The use of the fixed rate term debt reflects the upfront investment and long term nature of the fixed assets being financed, and given the smaller projected size of the sustaining costs, FBCU submits that it would be more appropriate to allow the same rate to be maintained over the term of the contracts.

188.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 141.0, pp. 336-347

Basis for Calculating Deemed Interest Rate

In response to BCUC IR No.1, Question 141.2, the FBCU provide a hypothetical example of how to calculate the deemed interest rate, which includes an Issuance Fee. In the hypothetical example, the annualized issuance fee is 0.05 percent.

188.1 In practice, if the FBCU needed to calculate a deemed interest rate that would apply to the long-term portion of the deemed debt of a small utility without third-party debt, please explain exactly how the FBCU would calculate a reasonable issuance fee. Please provide the supporting Excel live spreadsheet with formulas if one is used.

Response:

In keeping with the example provided in BCUC IR 1.141.2, the following example displays how the 0.05% fee is calculated, see below.

For a hypothetical $100 million issue

Coupon Rate	4.25%	
Calculation of Upfront Fee		
Commission to Agent	0.50%	$500K/$100MM
Rating Agency Issuance Fee	0.09%	$85K/$100MM
Legal & Other	0.06%	$55K/100MM
Upfront Fees(%)	0.64%	
Calculation of ongoing Annual Fee		
Annual Rating Agency Fee	115,000	
Debt Outstanding	1,386,000,000	
Debt Issue	100,000,000	
Annual Fee (%)	7%	
Annual Fee ($)	8,297.26	
Calculation of the Annualized Issuance Fee		
N	60	Periods
Pmt - Debt	2.125	Coupon
Pmt - Annual Fee	0.004	$10,606 per year X 50% for semi-annual periods
Total Pmt	2.13	Total Semi-Payment
PV	99.36	100- Less Upfront Fees
FV	100	
I/Y	4.30%	Effective Rate
Less:	4.25%	Coupon
Annualized Issuance Fee	0.05%	

For a small utility without third party debt, the annualized issuance fee will be higher due to the smaller size of the debt issue.

188.1.1 Specifically, what are the determinants of the issuance fee and why?

Response:

Please refer to the response to BCUC IR 2.188.1.

The annual issuance fee simulates the upfront costs and annual expected rating agency costs in terms of the overall cost of debt. It represents the hypothetical costs of an entity to borrow from a third-party under the terms of the borrowing on a standalone basis.

188.1.2 Would the size of the small utility or project affect the issuance fee?

Response:

The smaller the size of the issue, the more likely it is that the annualized issuance fee will be larger. The reason is that the administrative costs of borrowing, such as the fixed fees, are not dependent on the size of the issue. Therefore, on a relative basis, the administrative costs will make up a greater proportion of the overall cost of borrowing for a small debt issue, than for a larger debt issue, therefore the annualized issuance fee would be higher.

In response to BCUC IR No.1, Questions 141.5.1 and 141.5.2, the FBCU state that: "The more subjective component is determining the group of issuers that are viewed as comparable, and the industries they are drawn from" and further that "[t]he subjectivity can be reduced by first attempting to identify proxy companies that are engaged in similar industries or lines of business."

188.2 Please complete the following table:

Circumstances for which deemed debt is appropriate (per FBCU's response to BCUC IR No. 1, question 140.1, p. 333):	**Please identify the comparable industries/lines of business for each circumstance described. Why?**
1. Separate division within a larger regulated utility: e.g., Fort Nelson	
2. Separate class of service within a larger regulated utility: e.g. TES projects such as Delta SD and Tsawwassen Springs	
3. Regulated subsidiary within a larger corporate organization: e.g., FEW	

Response:

Circumstances for which deemed debt is appropriate (per FBCU's response to BCUC IR No. 1, question 140.1, p. 333):	**Please identify the comparable industries/lines of business for each circumstance described. Why?**
1. Separate division within a larger regulated utility: e.g., Fort Nelson	Regulated Utility, Power Generation, Energy Infrastructure
2. Separate class of service within a larger regulated utility: e.g. TES projects such as Delta SD and Tsawwassen Springs	Regulated UtilityPower Generation, Energy Infrastructure
3. Regulated subsidiary within a larger corporate organization: e.g., FEW	Regulated Utility, Power Generation, Energy Infrastructure

The FBCU's responses to BCUC IRs 1.141.5.1 and 1.141.5.2 were intended to explain that because of the scarcity of certain issuers with observable credit spreads, such as BBB rated entities, companies in industries that are broadly similar, such as Power Generation or Energy Infrastructure, may also serve as proxy issuers. As such, in those circumstances above, Power Generation and Energy Infrastructure may also be considered.

188.3 For each of the circumstances described in the table above, would the FBCU view the following industries as comparable, and why?

a) Power

Response:

Based on the response to BCUC IR 2.188.2, issuers in the Power sector could be considered as proxies for determining debt spread for a TES project based on the fact that TES projects may consist of energy generating equipment, which can be viewed as broadly similar with power generation.

b) Energy Infrastructure

Response:

Based on the response to BCUC IR 2.188.2, for the purposes of identifying proxy issuers, as both the small utilities and energy infrastructure companies are generally involved in the operation of assets delivering energy, those companies can be considered similar.

c) Telecommunications

Response:

The FBCU do not view the Telecommunications as a comparable industry. The industry does not involve services related to the circumstances provided in the table above.

In response to BCUC IR No.1, Question 141.6.1, the FBCU state that: "In general, however, given the current level of interest rates, and the fact that an embedded rate incorporates the cost of past debt issuances, a current deemed cost of debt is likely to be higher than the actual (market) cost of debt for that utility." [Emphasis added]

188.4 Regarding the underlined phrase above, do the FBCU mean to say that the embedded cost of debt is likely to be higher than the actual (market) cost of debt? If not, please clarify what the FBCU meant to say.

Response:

Yes, the FBCU mean to say that in today's market, the embedded cost of debt is likely to be higher than the actual (market) cost of debt given that the current interest rate environment for long-term debt is lower than it has been.

In response to BCUC IR No.1, Question 141.8, the FBCU state that: "On the other hand, such [alternative energy] projects are being financed from a pool of debt raised by a single issuer, as it is inefficient and too costly for each project to raise funds on its own. The use of the embedded cost implicitly recognizes that, typically, when new funds are raised by an issuer, those funds are not colour-coded for, and traced to, a particular project or service. While embedded cost rates are likely to deviate from market rates of interest at any given time, due to issuance timing, where the issuer's cost of debt is unlikely to be measurably affected by the financing of projects, using an embedded cost of debt is an administratively efficient way to allocate debt issued by a single regulated entity, allows the benefits that issuing all debt centrally to be shared, and provides a reasonable degree of assurance that the regulated entity that raises the debt will be able to recover its actual incurred costs of debt."

188.5 In the case of FAES' projects such as Delta SD, Tsawwassen Springs and Marine Gateway, for which a deemed interest debt rate has been calculated using "Option 1 – Assign a credit rating," please identify the entity who is raising the debt that will be used to finance these projects.

Response:

FAES will borrow from its direct parent FortisBC Holdings Inc. (FHI), which in turn will receive the funding through its ultimate parent, Fortis Inc.

188.5.1 If the issuing entity is FEI, how would the actual incurred cost of debt rate on the pool of debt used to finance these projects be determined? Would the more recent long-term debt issue be the most representative debt rate? Why or why not?

Response:

The FBCU's response to BCUC IR 1.141.8 indicates that the actual incurred cost of debt would not be used to finance these projects. Rather the "embedded cost of debt" is used to finance the projects. The embedded cost of debt, which is the weighted average historical cost of debt currently outstanding at FEI (including the actual incurred cost of the incremental debt used to the finance the noted projects) would be the rate used. The embedded cost of debt is the most representative debt rate, because, as described in BCUC IR 1.141.8, the funds raised are not specifically allocated to certain projects, rather the cost of debt is recovered from all customers at the same rate, irrespective of when the timing of the debt issue and specific use of the debt on behalf of a specific customer occurred.

188.5.2 If FEI's actual incurred cost of debt rate is higher than the deemed interest cost of debt rate allowed in Delta SD (5.37%), Tsawwassen Springs (5.01%) and Marine Gateway (5.37%), which regulated entity pays for the difference?

Response:

Please refer to the response to BCUC IR 2.188.5. FAES borrows the funds from FHI, not FEI. The deemed debt rate for each project is determined on a standalone basis and is intended to reflect the current market cost of debt for those projects. The actual cost of debt is incurred by FHI. That differential, positive or negative, would be assumed by FHI.

There was an error in BCUC IR No.1, Question 141.9. Please provide the FBCU's response to the corrected BCUC IR, which reads as follows:

188.6 Given the scarcity of BBB-rated utilities in Canada that can be used as proxy for the TES class of service, and the possibility that utilities with BBB rating be upgraded/ downgraded at some point, please comment on the pros and cons of the following methodology to calculate the deemed long-term debt rate for TES projects:

- Step 1: Obtaining the yield on an appropriate Government of Canada bond as the benchmark;
- Step 2: Obtaining the bond yield spread between the Government of Canada bond benchmark and a high grade utility (A or A low utility) and adding it to the rate in Step 1;
- Step 3: Obtaining the spread between BBB-rated utility bond spreads and A-rated utility bond spreads. This step could be looking at historical data (e.g., two most recent years) to have more data points. Then, adding this spread between BBB and A-rated utility bond spreads to the rate calculated in Step 2.

Response:

The steps listed above appear to be a reasonable approach to determining the cost of deemed debt.

Pro's

- The approach would appear to be transparent and verifiable. It is a logical relationship between the spreads in step 2 and 3.
- The data would be expected to be based on comparable entities improving the reliability of the data.

Con's

- As noted, there is a scarcity of BBB rated utility issuers in Canada.
- In the BBB rated utility sector, terms of debt tend to be shorter and there may be few issues over 10 years in term.
- Use of a universe of bonds limits the ability to easily identify a spread to match a specified term for the debt, as the term of the deemed debt may be different than the average term of the BBB rated index or universe. A mechanism would need to be developed to adjust the rate of the deemed debt if the designated term of the debt is materially different than that of the universe of BBB-rated utility bonds.

The FBCU submit that, as an alternative, if there was a reasonable universe or index representing BBB-rated Canadian utility bonds, then the interest rate on that index could be used as the proxy rate instead of the steps noted above. The only adjustment would then need to be any adjustment to rate if the term for the deemed debt was materially different than the average term of the universe of BBB utility issuers.

In response to BCUC IR No.1, question 141.10, the FBCU state that: "The term of debt can be matched to the term of a contract or a term that represents the longer-term nature of the assets, i.e., long-term assets are financed with long-term debt. In the FBCU's view, the deemed debt rate should be fixed to match the selected term. The FBCU do not see any pros with annual varying the imputed cost of debt for what in principle should be viewed as a fixed-rate debt instrument. Varying a long-term debt rate annually potentially exposes the issuer or the customer to avoidable interest rate risk."

188.7 Would the FBCU not agree that one "pro" of varying annually the deemed debt rate would be a fair treatment of the utility and the customers in both declining and rising interest rate environments? If not, why not?

Response:

The FBCU does not in principle agree with the characterization of the varying interest rate as a 'pro'. By varying the interest rate as characterized in the question, in a declining interest rate environment, there may be an advantage, but in an increasing interest rate environment, it would be a disadvantage. By varying the rate annually, interest rate risk is introduced. The FBCU believe that as capital is funded at a point in time, and those assets are longer term in nature, a more appropriate approach is to fix the interest rate to provide cost certainty.

188.8 If, in approving the rates for a regulated thermal energy project, the Commission were to fix the deemed debt rate to match the term of the contract or a term that represents the longer-term nature of the assets, say 20 years, please confirm that under no circumstances would the regulated entity carrying the project come back to the Commission to request an increase in the deemed debt rate.

Response:

If the regulated entity applied for a fixed deemed debt rate for an amount of debt, then the expectation would be that the rate would be set for the period in question. Additional debt issuance by the entity in question should reflect the appropriate rate applied for at the time the debt was to be incurred.

It is impossible to say definitively that the entity would not consider increases to the debt rate under any circumstances, but the FBCU are not aware of any circumstance that would warrant a change to an approved fixed debt rate.

188.8.1 If not, please explain which specific circumstances could justify the regulated entity coming back to the Commission to request an increase in the deemed debt rate, before the end of the previously approved 20-year term.

Response:

Please refer to the response to BCUC IR 2.188.8.

In response to BCUC IR No.1, Question 141.11, the FBCU state that: "With respect to TES projects, the FBCU are of the view that an individual TES project will likely not have a significant business risk difference from other TES projects. The FBCU believe that it is reasonable, in order to achieve regulatory efficiency and streamline the regulatory process for these projects, to consider utilizing consistent capital structures, equity risk premiums and designated stand-alone credit ratings for each project that falls within the TES class of service, when determining the specific debt for such projects."

188.9 Please confirm that, in the FBCU's view, all TES projects, whether carried through by the FBCU, FAES, Corix or River District Energy Partnership Limited, should have the same capital structure, equity risk premium, and designated stand-alone credit ratings in order to achieve regulatory efficiency. If not, why not?

Response:

The ROE and capital structure of TES project should be commensurate with the risk associated with the project. Most TES projects are going to be broadly similar in this regard (although it is possible that exceptions might exist). The projects can therefore typically have the same capital structure, equity risk premium and designated standalone credit ratings and thereby achieve regulatory efficiency.

189.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 143.0, pp. 349-354

Portions of Short-Term and Long-Term Debt

In response to BCUC IR No.1, Question 143.2, the FBCU state that: "For example, short-term financing in FEI's capital structure averaged 4.6% at year-end over the past 5 years and reached a low of 0.1% and a high of 9.4% at year-end December 31 2011 and 2008, respectively. FBCU speculate that short-term financing (floating rate) could range from 0-10% as seasonality, gas prices, rates and capital expenditures impacts may vary the amount."

189.1 In contrast to the example cited in the preamble, short-term financing in the capital structure of FEVI and FEW exceeded 10% respectively in eight and nine years of the 2002-2012 period, and in up to four years for Fort Nelson and FortisBC Inc. Given this reality, please explain why the FBCU would speculate that short-term financing would not exceed 10 percent?

Response:

FEVI and FEW incurred very large capital spending programs as a percentage of their overall rate base during the period of 2002-2012, which can account for the temporary higher short-term debt balances. As noted and to clarify, the short-term debt balance of a Utility can vary due to seasonality, gas prices, rates and capital expenditures, however, the short-term debt balance on average would likely track in the range of 0-10%. This is supported by reference to FEI's average short-term debt balance as noted in response to BCUC IR 2.189.2.

In response to BCUC IR No.1, Question 143.3, the FBCU provide tables for each of the utilities within the FBCU group with information on short-term and long-term debt, common equity and preferred shares.

189.2 Please add a line at the end of each table that provides the average across each of the eight columns. In doing so, please copy in the new response the entire table provided in response to BCUC IR No.1, question 143.3 and add the average line.

Response:

Please refer to the following updated tables:

Name of Utility: FortisBC Energy Inc.								
Years	**Short-Term Debt**		**Long-Term Debt**		**Common Equity**		**Preferred Shares**	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)	Share of Capital Structure (%)	Terms of Return (%)
2012 (Approved)	1.93%	2.50%	58.07%	6.85%	40.00%	9.50%	0.00%	0.00%
2011	0.12%	4.50%	59.88%	6.95%	40.00%	9.50%	0.00%	0.00%
2010	1.24%	2.25%	58.76%	6.95%	40.00%	9.50%	0.00%	0.00%
2009	3.86%	4.25%	61.13%	6.96%	35.01%	8.99%	0.00%	0.00%
2008	9.41%	5.00%	55.58%	7.21%	35.01%	8.62%	0.00%	0.00%
2007	4.37%	4.75%	60.62%	7.02%	35.01%	8.37%	0.00%	0.00%
2006	6.33%	4.00%	58.67%	7.07%	35.00%	8.80%	0.00%	0.00%
2005	7.01%	4.00%	59.99%	7.26%	33.00%	9.03%	0.00%	0.00%
2004	9.97%	3.25%	57.03%	7.37%	33.00%	9.15%	0.00%	0.00%
2003	7.28%	4.00%	59.72%	7.56%	33.00%	9.42%	0.00%	0.00%
2002	6.53%	2.90%	60.47%	7.80%	33.00%	9.13%	0.00%	0.00%
Average	5.28%	3.76%	59.08%	7.18%	35.64%	9.09%	0.00%	0.00%

Name of Utility: FortisBC Energy Inc. - Fort Nelson								
Years	**Short-Term Debt**		**Long-Term Debt**		**Common Equity**		**Preferred Shares**	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)	Share of Capital Structure (%)	Terms of Return (%)
2012 (Approved)	2.44%	2.50%	57.56%	6.85%	40.00%	9.50%	0.00%	0.00%
2011	12.13%	4.50%	47.87%	6.95%	40.00%	9.50%	0.00%	0.00%
2010	5.66%	4.25%	54.34%	6.95%	40.00%	9.50%	0.00%	0.00%
2009	5.02%	4.25%	59.97%	6.96%	35.01%	8.99%	0.00%	0.00%
2008	7.31%	5.00%	57.68%	7.22%	35.01%	8.62%	0.00%	0.00%
2007	13.39%	3.25%	51.60%	7.37%	35.01%	8.37%	0.00%	0.00%
2006	10.93%	3.25%	54.07%	7.37%	35.00%	8.80%	0.00%	0.00%
2005	7.38%	3.25%	59.62%	7.37%	33.00%	9.03%	0.00%	0.00%
2004	8.52%	4.00%	58.48%	7.37%	33.00%	9.15%	0.00%	0.00%
2003	6.12%	4.00%	60.88%	7.56%	33.00%	9.42%	0.00%	0.00%
2002	15.52%	2.90%	51.48%	7.80%	33.00%	9.13%	0.00%	0.00%
Average	8.58%	3.74%	55.78%	7.25%	35.64%	9.09%	0.00%	0.00%

Name of Utility: FortisBC Energy (Vancouver Island) Inc.

Years	Short-Term Debt		Long-Term Debt[1]		Common Equity		Preferred Shares	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)	Share of Capital Structure (%)	Terms of Return (%)
2012 (Approved)	13.13%	4.00%	46.87%	5.73%	40.00%	10.00%	0.00%	0.00%
2011	5.13%	6.80%	54.87%	5.63%	40.00%	10.00%	0.00%	0.00%
2010	10.19%	4.23%	49.81%	4.62%	40.00%	10.00%	0.00%	0.00%
2009	11.04%	2.86%	48.96%	5.09%	40.00%	9.59%	0.00%	0.00%
2008	10.81%	5.20%	49.19%	5.98%	40.00%	9.32%	0.00%	0.00%
2007	3.81%	5.18%	56.19%	5.19%	40.00%	9.07%	0.00%	0.00%
2006	2.88%	4.86%	57.12%	4.91%	40.00%	9.50%	0.00%	0.00%
2005	18.45%	3.53%	46.55%	4.56%	35.00%	9.53%	0.00%	0.00%
2004	15.94%	2.13%	49.06%	5.12%	35.00%	9.65%	0.00%	0.00%
2003	14.35%	3.27%	50.65%	6.85%	35.00%	9.92%	0.00%	0.00%
2002	12.78%	2.40%	52.22%	7.62%	35.00%	9.25%	0.00%	0.00%
Average	10.77%	4.04%	51.04%	5.57%	38.18%	9.62%	0.00%	0.00%

(1) The government loans to FEVI are treated as a credit to PPE and so are not shown as part of FEVI's capital structure.

Name of Utility: FortisBC Energy (Whistler) Inc.

Years	Short-Term Debt		Long-Term Debt		Common Equity		Preferred Shares	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)[1]	Share of Capital Structure (%)	Terms of Return (%)
2012 (Approved)	11.76%	3.50%	48.24%	5.11%	40.00%	10.00%	0.00%	0.00%
2011	15.81%	5.15%	44.19%	5.11%	40.00%	10.00%	0.00%	0.00%
2010	15.95%	2.90%	44.05%	5.11%	40.00%	10.00%	0.00%	0.00%
2009	11.98%	5.10%	48.02%	5.93%	40.00%	9.49%	0.00%	0.00%
2008	17.34%	4.00%	47.66%	5.10%	35.00%	9.22%	0.00%	0.00%
2007	17.47%	4.00%	47.53%	5.10%	35.00%	8.97%	0.00%	0.00%
2006	18.05%	5.68%	46.95%	4.90%	35.00%	9.40%	0.00%	0.00%
2005	18.22%	3.27%	46.78%	5.10%	35.00%	9.75%	0.00%	0.00%
2004	17.51%	3.56%	47.49%	5.10%	35.00%	9.75%	0.00%	0.00%
2003	0.00%	0.00%	65.00%	4.70%	35.00%	10.02%	0.00%	0.00%
2002	0.00%	0.00%	65.00%	6.52%	35.00%	9.73%	0.00%	0.00%
Average	13.10%	3.38%	50.08%	5.25%	36.82%	9.67%	0.00%	0.00%

(1) In 2006, the AAM produced a 9.40% approved ROE for FEW, however, the BCUC did not approve rates in 2006 and so 2005 rates were used (based on the approved 2005 ROE).

FortisBC Inc.

Years	Short-Term Debt[1]		Long-Term Debt		Common Equity		Preferred Shares	
	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Interest Rate (%) (Actual)	Share of Capital Structure (%)	Allowed Cost of Equity (Approved)	Share of Capital Structure (%)	Terms of Return (%)
2012[2]	2.66%	2.89%	57.34%	5.92%	40.00%	9.90%	0.00%	0.00%
2011	0.09%	2.46%	59.91%	6.04%	40.00%	9.90%	0.00%	0.00%
2010	4.19%	2.87%	55.81%	6.18%	40.00%	9.90%	0.00%	0.00%
2009	2.09%	2.06%	57.91%	6.33%	40.00%	8.87%	0.00%	0.00%
2008	1.41%	3.38%	58.59%	6.36%	40.00%	9.02%	0.00%	0.00%
2007	3.16%	5.17%	56.84%	6.50%	40.00%	8.85%	0.00%	0.00%
2006	1.55%	4.82%	58.45%	6.49%	40.00%	9.20%	0.00%	0.00%
2005	6.30%	3.42%	53.70%	6.75%	40.00%	9.43%	0.00%	0.00%
2004	14.69%	4.82%	45.31%	7.07%	40.00%	9.55%	0.00%	0.00%
2003	12.81%	6.77%	47.19%	7.81%	40.00%	9.82%	0.00%	0.00%
2002	9.03%	6.11%	50.97%	7.76%	40.00%	9.53%	0.00%	0.00%
Average	5.27%	4.07%	54.73%	6.65%	40.00%	9.45%	0.00%	0.00%

[1] With the exception of 2012, short-term interest rates above consider the weighted average rate of actual draws on the operating credit facility. All the above short-term interest rates do not include fixed financing fees such as banking agreement renewal charges, annual lender and agency fees, letter of credit fees or overdraft facility interest.

[2] 2012 and 2013 short-term and long-term interest rates and share of capital structure are representative of the most recent forecast that resulted from the 2012-2013 Revenue Requirements Decision from August 15, 2012. These forecasted figures have not yet been submitted to the Commission for approval, therefore these amounts are preliminary in nature.

190.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 144.4, p. 356

Deemed Interest Rate for Short Term Debt

The FBCU state that "To estimate the short-term debt rate for Ontario Electricity Distributors, the OEB obtains <u>up to six quotes</u>. If it obtains six quotes, it discards the highest and the lowest and uses the average of the remaining four. If less than four are obtained, it uses the average of all the quotes it obtains." [Emphasis Added]

190.1 The FBCU indicate that the approach used by the OEB is reasonable. Should there be a minimum number of quotes obtained? Why or why not?

<u>Response:</u>

Yes, the FBCU consider that there should be a minimum number of quotes obtained. Having a minimum number of quotes would provide the Commission with a degree of assurance that the results are more representative of a consensus view.

191.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 144.5, p. 357

Deemed Interest Rate for Short-Term Debt

In response to BCUC IR No.1, Question 144.5, the FBCU state that: "The formulaic approach taken by the OEB is an efficient way of estimating a deemed short-term debt rate for the types of utilities referenced in the question. However, the OEB methodology is premised on a single debt rating, a short-term debt rating of R1-low, which generally maps to long-term credit ratings in the A category, higher than would be applicable to the referenced small utilities in the information request above" and, in response to BCUC IR No.1, question 144.5.1, "[t]hat disadvantage can be overcome by specifying a more reasonable credit rating for affected utilities. e.g., BBB/BBB(low) on DBRS's long-term rating scale."

191.1 In FBCU's view, what is the appropriate short-term debt rating that would correspond to the FBCU's proposed BBB/BBB(low) on DBRS' long-term scale? Why?

Response:

The corresponding short-term ratings would be R-2 (mid) to R-2 (low). In its report *Rating Scales: Short-Term and Long-Term Rating Relationships*, DBRS shows how long-term and short-term ratings typically map. Long-term ratings in the BBB to BBB(low) category generally map to short-term ratings of R-2 (mid) to R-2 (low).

192.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 146.0, pp. 360-362

Applicable Circumstances for Deemed Capital Structure with Deemed Debt

Ms. McShane states on page 122 of Exhibit B1-9-6, Appendix F, that "[w]hile, as discussed below, there are common approaches that the Commission can rely upon for the specific utilities to which a deemed debt cost might apply, the number of potentially affected utilities is relatively small, and the need to approve a deemed cost of debt relatively infrequent. <u>The individual utilities' circumstances may be different, in terms of risk, the funding requirements and appropriate terms of debt.</u> As a result, I recommend that the Commission continue to address the cost of debt for each utility separately."

In response to BCUC IR No.1, Question 146.1.1, the FBCU confirm that the following FAES projects: Delta SD, Tsawwassen Springs and Marine Gateway also fit the definition of 'small utilities' for the purpose of determining whether a deemed debt cost may be warranted.

In response to BCUC IR No.1, Question 141.11 (p. 344), the FBCU submit that: "<u>With respect to TES projects, the FBCU are of the view that an individual TES project will likely not have a significant business risk difference from other TES projects</u>. The FBCU believe that it is reasonable, in order to achieve regulatory efficiency and streamline the regulatory process for these projects, to consider utilizing consistent capital structures, equity risk premiums and designated stand-alone credit ratings for each project that falls within the TES class of service, when determining the specific debt for such projects."

192.1 Please clarify the statements that, on one side, the individual utilities' circumstances may be different, in terms of risk, which would justify that the Commission addresses the cost of debt for each utility separately, and on the other side, an individual TES project (i.e., a small utility) will likely not have a significant business risk difference from other TES projects, which would justify the use of consistent designated stand-alone credit ratings for TES projects.

<u>Response:</u>

As suggested in response to BCUC IR 1.141.11, the FBCU support a case specific approach to establishing the cost of debt, which means that the approach to be used in a particular case considers the type of utility involved. While the FBCU support a streamlined process for projects that fall within the TES class of service, not all utilities for which a deemed cost of debt might be appropriate would necessarily be TES projects or have similar risk profiles to TES projects. Further, even for TES projects specifically, the appropriate term of debt may not necessarily be the same for all TES projects. Streamlining the process for the TES class of service by utilizing consistent capital structures, equity risk premiums and designated stand-alone credit ratings for each project that falls within the TES class of service, when determining the specific debt for such projects still allows for flexibility in the determination of the specific term and cost of debt for those projects and accommodates taking account of the specific circumstances and risk profile of utilities that are not in the TES class of service.

In response to BCUC IR No.1, Question 146.4, the FBCU state that: "This means that the OEB needs to address 20 revenue requirements applications every year for the electricity distributors alone, including resetting the cost of any existing affiliate and deemed debt and setting the cost of forecast affiliate and deemed debt. In contrast, in BC, for TES projects, the Commission needs to establish the cost of debt much less frequently. For example, in the case of the FAES Delta School District No. 37 project, the term of the deemed debt is 20 years." [Emphasis added]

In Directive 1d) in Commission Order G-71-12, with respect to FAES's Revisions to Rates and Rate Design for Thermal Energy Services to Delta School District Number 37, the Commission directed as follows:

"d. The cost of debt rate of 5.91 percent filed by FAES is denied as it does not meet the condition and intent set out in Directive 3(c) of Order G-31-12. FAES is directed to re-calculate its deemed cost of debt rate based on BBB-rated entities operating specifically in the Thermal Energy Services (TES) class of service and file it with the Commission within 10 business days from the date of this Order. However, if FAES is not able to find such entities, the Panel would accept if FAES used BBB-rated distribution utilities, such as AltaGas Ltd. and Emera Inc., as proxy for the TES class of service. Further, going forward:

i. If the Commission approves, in the Generic Cost of Capital (GCOC) proceeding, a methodology to establish a deemed interest rate automatic adjustment mechanism (Interest AAM), FAES is directed to update its cost of debt rate annually using that Interest AAM.

ii. Alternatively, if the Commission does not approve an Interest AAM in the GCOC proceeding, FAES is directed to review its deemed cost of debt rate in its revenue requirements annual filing, using the same methodology as directed in this Order and accompanying Reasons for Decision."

192.2 In light of Directive 1d) in Commission Order G-71-12, please clarify the statement that the term of the deemed debt is 20 years in the Delta SD case.

Response:

The FBCU acknowledge that the Commission stated in the referenced decisions that, if the Commission approves an interest automatic adjustment mechanism in this proceeding, FAES should update its cost of debt rate annually using that mechanism or, alternatively, if the Commission does not approve an Interest AAM, FAES is to review its deemed cost of debt rate in its revenue requirements annual filing starting in Year 4, and make any adjustments to the deemed cost of debt that the Commission makes. In the FBCU's submission, it would not be appropriate to subject the deemed cost of debt for TES projects to an interest automatic adjustment mechanism, and therefore recommends that the Commission not implement such a mechanism. The deemed debt rate is based on the cost of a 20-year issue. That cost rate should remain unchanged for the 20-year implied term of the debt, consistent with the manner in which the cost of debt is set for utilities that actually raise third-party debt. This is also consistent with the general principle that utility assets are long-term assets and the debt component of the capital structure should be largely financed with long-term debt. As noted in response to BCUC IR 1.141.10, "The FBCU do not see any pros with annual varying the imputed cost of debt for what in principle should be viewed as a fixed-rate debt instrument. Varying a long-term debt rate annually potentially exposes the issuer or the customer to avoidable interest rate risk."

In response to BCUC IR No.1, Question 146.4.1, the FBCU state that: "The FBCU do not have a threshold number of utilities in mind. <u>The issue is relevant if the utilities have debt costs that are revisited annually or on a relatively frequent basis. To date in BC, that does not appear to be the case as the debt being approved in the case of FBCU affiliated projects will be term debt."</u> [Emphasis added]

On page 50 of the Commission Decision on the Marine Gateway TES project, the Commission determined that: **"The Commission Panel finds that the deemed cost of debt rate of 5.37 percent is appropriate and the methodology to calculate it to be consistent with that approved in both the DSD decision and the Tsawwassen Springs decision**. Further, going forward, if the Commission approves, in the Generic Cost of Capital (GCOC) proceeding, a methodology to establish a deemed interest rate automatic adjustment mechanism (Interest AAM), FAES is directed to update its cost of debt rate annually using that Interest AAM. Alternatively, if the Commission does not approve an Interest AAM in the GCOC proceeding, FAES is directed to review its deemed cost of debt rate in its revenue requirements annual filing starting in Year 4, using the same methodology as directed in this Decision. FAES is also directed to adjust its cost of service, including the cost of debt, each year for any changes that the BCUC makes." [Emphasis in the original]

192.3 In light of the Commission Directives in the Delta SD and Marine Gateway Decisions regarding the cost of debt rate, would the FBCU continue to believe that the issue of streamlining the deemed cost of debt for utilities without third-party debt is irrelevant? Why or why not?

Response:

The issue of streamlining the deemed cost of debt with an AAM is relevant in the GCOC because the Commission has said it is an issue in this proceeding. The FBCU's discussion in BCUC IR 1.146.4.1 was making the point that the deemed rate should be in place for the long term to reflect the nature of the assets, making it unnecessary and undesirable to adjust annually with a mechanism. Please refer to the responses to BCUC IRs 1.141.10 and 2.192.2.

193.0 Reference: Exhibit B1-20, Response to BCUC IR No. 1, Question 147.1, p. 363

Appropriate Basis to Calculate a Deemed Interest Rate

In response to BCUC IR No. 1, Question 147.1, the FBCU state that: "Consequently, estimating their stand-alone credit rating is inherently a less objective process than it would be for a large utility with rated peers. Ms. McShane considers that there are four key factors that should be considered with respect to the small utilities: (1) they all operate in the same economic environment and energy policy environment as the benchmark utility, FEI; (2) they are all regulated; (3) they are very small; and (4) their equity ratios are likely to be within the range of equity ratios adopted for other Canadian utilities. As they are regulated, it would be reasonable to proceed on the premise that, in theory, they could all be considered to be investment grade. The fact that they are very small, with the inherent risks of small size set out in response to BCUC IR 1.139.5, would preclude them from achieving ratings equal to those of the benchmark. A reasonable deemed stand-alone rating for a small, but regulated, utility is in the range of BBB to BBB(low), with the deemed debt cost set on this basis."

On page 48 of the Commission Decision on FAES' Marine Gateway, the Commission states: "The Panel accepts FAES' portrayal of the Project as low risk both from an operational and revenue perspective." Furthermore, on page 51, the Panel denied the 50 basis points premium.

193.1 In instances where the business risks of a small TES projects are not found to be higher than those of the benchmark utility, please discuss why the credit rating assigned to the small TES could not be equal to that of the benchmark.

Response:

Despite the fact that the Commission may conclude that the fundamental business risks of the project are not higher than those of the benchmark utility, size alone would preclude the small utility from achieving the same debt rating and cost of debt on a stand-alone basis as the benchmark utility. No company of the size of the TES projects would have access to debt on a stand-alone basis at the same cost and on the same terms and conditions as the benchmark utility.

194.0 Reference: Exhibit B1-9-1, Testimony of Ms. McShane, Schedule 19-21

DCF estimates

Ms. McShane provides DCF based estimates of the cost of equity of the comparative sample of U.S. utility companies.

194.1 Of the sample provided, which entities are publicly traded operating companies rated A3 or higher?

Response:

As shown on Ms. McShane's Schedule 15 Page 1 of 2, Northwest Natural Gas, Piedmont Natural Gas, Vectren Corp., WGL Holdings Inc., and Wisconsin Energy Corp. are rated A3 or higher by Moody's. In addition to these five companies, Consolidated Edison, Integrys Energy Group Inc., Southern Company, and Xcel Energy Inc. are rated A- or higher by S&P, which is the equivalent of Moody's A3 rating.

194.2 How do the A3 or higher rated publicly traded operating companies' DCF equity estimate compare to the mean estimate of the total U.S. sample?

Response:

Ms. McShane provides the following response.

The table below compares the mean and median DCF equity estimates of the total U.S. sample to those companies rated A3 or higher by Moody's and to those companies rated A- or higher by S&P.

	Constant Growth DCF		Sustainable Growth DCF		Three Stage DCF	
Sample	**Mean**	**Median**	**Mean**	**Median**	**Mean**	**Median**
Total U.S.	9.3%	9.3%	8.8%	8.6%	9.2%	9.2%
Rated A3 or Higher by Moody's	8.9%	8.7%	8.7%	8.0%	9.0%	8.7%
Rated A- or Higher by S&P	9.2%	8.9%	8.7%	8.5%	9.1%	8.8%

194.3 Why is the "SV growth" of Northwest Natural Gas substantially higher than all the rest of its U.S. peers?

Response:

Ms. McShane provides the following response.

Value Line estimates that Northwest Natural will have the largest growth rate in the number of common shares outstanding of any company in the sample between 2011 and 2015-2017 at 2.99%. *Value Line* also estimates that Northwest Natural Gas will have the second highest equity accretion rate in the sample at 49.4% for 2015-2017. The combination of these two factors leads to Northwest Natural Gas having the highest SV growth factor of the utilities in the U.S. sample.

194.4 How does a change of 1 percent in the long term growth assumption affect the DCF equity estimate?

Response:

Ms. McShane provides the following response.

In the context of the constant growth model, where there is a single growth rate expected to be maintained in perpetuity, a one percentage change in the long-term growth assumption would change the DCF cost of equity estimate by the same one percentage point. In the context of the three-stage growth model, a one percentage point change in the long-term growth assumption, i.e., the expected growth rate in nominal GDP, would change the DCF cost of equity estimate by approximately 75 basis points.

194.5 What are the assumptions used to estimate the long term nominal GDP growth rate of 4.9% in schedule 21? What is the associated assumption of inflation and real growth? Has this forecast changed? What is the basis and source of this nominal GDP forecast? What has been the actual experience of GDP in recent years?

Response:

Ms. McShane provides the following response.

The long-term nominal GDP growth rate of 4.9% was taken from the March 2012 edition of the Blue Chip *Economic Indicators*, as indicated on Schedule 21 and page C-10 of Ms. McShane's evidence. The 4.9% represents the consensus of forecasts from more than 50 leading business economists.

The associated forecast GDP inflation rate for the period 2013-2023 is 2.2%; the corresponding forecast real GDP growth is 2.7%. The October 2012 edition of the Blue Chip *Economic Indicators* includes a consensus forecast of long-term nominal GDP growth rate of 4.8%.

The annual levels of nominal GDP for the years 1989-2011, as shown in Ms. McShane's Schedule 1, along with the corresponding rates of growth are presented in the table below.

Year	Current Dollars GDP	Yearly Growth
1989	100.0	
1990	105.8	5.8%
1991	109.3	3.3%
1992	115.7	5.8%
1993	121.6	5.1%
1994	129.2	6.3%
1995	135.3	4.7%
1996	143.0	5.7%
1997	152.0	6.3%
1998	160.4	5.5%
1999	170.6	6.4%
2000	181.5	6.4%
2001	187.6	3.4%
2002	194.1	3.5%
2003	203.2	4.7%
2004	216.2	6.4%
2005	230.3	6.5%
2006	244.0	6.0%
2007	255.9	4.9%
2008	260.7	1.9%
2009	254.3	-2.5%
2010	265.0	4.2%
2011	275.3	3.9%

194.6 What are the expected drivers of long term growth for the regulated assets of FortisBC Energy Inc.? What has been the historical experience of the different factors of growth?

Response:

The long-term drivers of growth for FEI's regulated assets are expected to be largely related to energy use and throughput, new customer attachments, investments for system reliability and integrity and replacement of aged infrastructure. The drivers of growth in FEI's regulated assets are expected to be similar to those which have driven growth in regulated assets historically.

195.0 Reference: Exhibit B1-9-6, Testimony of Ms. McShane, p. 77

Cost of Capital

Ms. McShane provides a long term forecast of the 30 year risk free rate of 5 percent, based on a Consensus Economics Survey report.

195.1 How has the Consensus Economics Survey long term bond yield forecasts compared to actual experience? What is the accuracy of the Survey in terms of direction of movement of yields and degree of change in yields?

Response:

For clarification, the 5.0% 30-year Canada bond yield which the question references is the yield expected to prevail on average over the longer-term. It is not the forecast 30-year Government of Canada bond yield that Ms. McShane relied on in the estimation of the benchmark utility cost of equity. Ms. McShane used a 30-year Canada bond yield of 4.0%, representing the forecast yield for 2013-2015 only.

As noted at footnote 83 of Ms. McShane's testimony, *Consensus Economics* does not publish forecasts of 30-year Canada bond yields; it only publishes a consensus forecast for the 10-year Canada bond yield. Each month it publishes forecasts of the 10-year Canada bond yield for three-months and twelve-months forward. Twice a year (April and October) it publishes the consensus forecast of 10-year Canada bond yields expected to prevail over the next ten years.

Prior to the elimination of the automatic ROE adjustment mechanism in 2009, the Commission used the November *Consensus Forecasts* to establish the BC utilities' ROE for the following year. The Commission used the average of the three-months and twelve-months forward *Consensus Forecasts*' 10-year Canada bond yields as the basis for estimating the 30-year Canada bond yield for the subsequent year. To test the accuracy of the *Consensus Forecasts*, Ms. McShane compared the average of the three-month forward and the twelve-month forward consensus forecasts of the 10-year Canada bond yield published in November to the average actual yield during the subsequent year for each year from 1991 to 2011. As Consensus Economics first started publishing the 10-year Canada bond yield forecasts in 1990, 1991 corresponds to the first year such comparisons could be made. Over the period 1991 to 2011, the actual average yield on 10-year Canada bonds exceeded the prior November forecast yield by 40 basis points. By comparison, if November actual yields had been used as a proxy for the following year's forecast, i.e., based on the premise that there will be no change in long-term interest rates, the forecast as proxied by actual yields would have exceeded the yield in the subsequent year, on average, by 30 basis points. In terms of the direction of movement, on average over the period, the consensus forecasts anticipated an average increase during the subsequent relative to the time of the forecast of approximately 10 basis points. By comparison, the subsequent year's yields were, on average, 30 basis points lower than actual yield at the time of the forecast.

195.2 Can existing market levels of bond yields be used as a more accurate indicator of future bond yields?

Response:

While the actual yields from the prior year have turned out to be a slightly more accurate predictor of the following year's actual yields than the forecasts, the objective of using the forecasts is to estimate the ROE based on investor expectations. Analyses which utilize the risk-free rate, such as the risk premium test, are forward looking and as such should reflect investors' outlooks for interest rates. The use of consensus forecasts is a transparent means of representing investors' expectations for the long-term Canada bond yield.

195.3 Exhibit A2-25 includes a Canadian Transportation Agencies' review of its methodology related to "Risk-free rate." Is Ms. McShane aware of this review and the CTA use of existing market levels of bond yields as the risk free rate for rate setting purposes?

Response:

Yes.

195.3.1 Please comment on the CTA's methodology versus the long term forecast used by Ms. McShane in her evidence.

Response:

The CTA uses a current (actual) yield on a relatively short-term (3-5 year) Government of Canada marketable bond as its proxy for the risk-free rate in the CAPM calculation for determining the cost of equity. Ms. McShane disagrees with the use of 3-5 year Government of Canada bond yields for the purpose of applying risk premium models, including the CAPM. As stated on page 77, lines 1981 to 1984 of her testimony, the "Use of the long-term government bond yield recognizes (1) the administered nature (determined by monetary policy) of short-term rates; and (2) the long-term nature of the assets to which the utility equity return is applicable." In addition, the use of a long-term government bond yield in the application of the CAPM, rather than a short-term rate that is typically used to test the model, partially compensates for the model's observed tendency to understate returns for relatively low beta stocks. Further, as stated in response to part of BCUC IR 2.195.2 above, the use of a consensus forecast ensures that investors' expectations for the long-term bond yield are represented. Finally, Ms. McShane is not aware of any regulatory decision in Canada outside of the CTA decision cited which has relied on other than a long-term Canada bond yield in the application of the CAPM or other risk premium test that uses a risk-free rate.

196.0 Reference: Exhibit B1-9-6, Testimony of Ms. McShane, p. 77

Equity Beta Estimates

Ms. McShane discusses the impediments to the use of equity beta.

196.1 Please discuss the conceptual and actual historical relationship between beta and equity returns.

Response:

Please see pages A-18 to A-26 of Ms. McShane's evidence.

197.0 Reference: Exhibit B1-11, Response to BC Utility Customers IR No. 1, Question 3.1, p. 20,

Deferral Accounts

The table shows FEI's rate base deferral accounts.

197.1 Please create another table showing the 2012 deferral accounts of FEI along with those of Enbridge Gas, Union Gas and for the three lowest risk US utilities included in the analyses of FBCUs experts.

Response:

Attachment 197.1 contains the requested information on the deferral accounts for FEI, Enbridge Gas, Union Gas, Northwest Natural Gas, Piedmont Natural Gas and WGL Holdings. As there no universally accepted measures of determining lowest equity risk, the latter three were chosen for this purpose on the basis of their debt ratings.

198.0 Reference: Exhibit B1-11, Response to BC Utility Customers IR No. 1, Question 3.2, p. 25,

Deferral Accounts and Risk

The FBCU state that the FEI deferral accounts have reduced short-term business risk but not long-term risk.

198.1 If most of FEIs short term revenue requirement risk is offset by deferral accounts and if the likelihood of over earning in any year is much higher than under earning, and if FEI would have to lose more than 80 percent of its residential customers before reaching Step 2 BC Hydro rates (Cross-reference Exhibit B-20, BCUC IR 2.1), how does this not reduce both short-term business risk and long-term business risk as the practice continues through time?

<u>Response:</u>

The use of deferral accounts, the achieved return on equity, and the current differential between natural gas rates and Step 2 BC Hydro rates do not reduce the long-term business risk of FEI as discussed below.

First, long-term business and regulatory risks (which are described in Appendix H) are not mitigated through the use of deferral accounts. Deferral accounts mitigate risk only in the context of the applicable revenue requirements test period, that is, as against short-term (generally one or two-year) forecasts. Over the longer term, deferral accounts cannot insulate the Company against risks such as a continuing decline in load and throughput, because subsequent short-term forecasts will recognize and incorporate the longer-term trend. For this reason, even if the utilization of deferral accounts were to continue, the underlying long-term risks would not be mitigated. Further, FEI would like to clarify that as shown in Table 1 in IR 1.96.1.1, approximately 64% of the total revenue requirement is covered by deferral accounts pertaining to variances in the flow through cost of gas. While FEI is protected against short term variances in commodity costs, the impact of changes in commodity costs on the long term demand of natural gas are not covered by these deferral accounts.

Second, as discussed in the response to BCUC IR 2.182.7, the performance of a company with respect to its achieved return on equity as compared to the allowed return on equity is not indicative of a change in either short term or long term business risk; it is a measure of the Company's ability to manage within the approved operating, capital and other cost limitations for that year.

Third, commodity price is only one factor impacting competitiveness of natural gas in BC relative to electricity and the recent decline in commodity price as has had little impact on FEI's overall business risk as discussed in the response to BCUC IR 1.97.1. Further, the BC Hydro Step 2 Rate should not be used as the only electricity benchmark for the reasons as discussed in the response to BCUC IR 1.2.1. While the analysis in the response to BCUC IR 1.2.1.1 shows that an 80% decline in throughput would be required for rates to reach the BC Hydro Step 2 Rate, there are other factors than price at play that give rise to competitive risk today. Despite the decrease in natural gas commodity costs over the last three years (the commodity rate in 2009 was 50% greater than 2012), the actual throughput has not increased proportionally – customers don't use proportionally more natural gas as the price falls. Moreover, although the price gap is reduced, FEI's exposure to customers leaving the system due to the non-price factors as discussed in Appendix H remains.

199.0 Reference: Exhibit B1-11, Response to ICG IR No. 1 to FBCU, Question 4.2, p. 37

Revenue Composition

For its comparative analysis of natural gas versus electricity the FBCU state that: "The efficiency of natural gas for hot water heating is assumed to be 60% vs. 90% for electricity, yielding an effective efficiency of 67 percent.

199.1 What is the current efficiency of a high efficiency natural gas hot water heater? What is the penetration rate of high efficiency hot water heaters for new residential construction?

Response:

The definition for a high efficiency hot water heater is not well defined in the marketplace, thus the FEU makes the assumption that an ENERGY STAR® eligible appliance qualifies as high efficiency. Using this assumption, the current efficiency for a natural gas storage hot water heater to be eligible as ENERGY STAR® is a minimum Energy Factor ("EF") of 0.67.[1]

The FEU do not track penetration rates of gas applications by efficiency as there are no reliable means available to track such factors at this time.

[1] Natural Resources Canada - http://oee.nrcan.gc.ca/equipment/heating/12007#waterheaters

200.0 Reference: Exhibit B1-12, Response to BC Utility Customers IR No. 1, Question 10.3, p. 20

Low debt costs for utilities

Mr. Engen shows that Canadian utilities can borrow money at lower cost to comparable corporate entities "because of the protective nature of the Canadian regulatory environment."

200.1 Shouldn't regulators consider this factor when trying to determine the most efficient capital structure of a utility?

Response:

Mr. Engen understands that regulators do so if not directly, then indirectly. The protective nature of the Canadian regulatory environment helps support higher credit ratings for regulated companies which supports borrowing at lower rates and allows regulated companies to include more debt in their capital structure.

200.2 Should they then be less concerned about maintaining "A" credit ratings for those utilities because they will protect the utilities from potential default on an ongoing basis?

Response:

Regulators should consider a capital structure that supports an A rating as part of meeting the tests under the fair return standard. As discussed at page 38 or Mr. Engen's written evidence, maintaining an A-category rating is important to providing regulated companies with consistent and ready access to the debt capital market on reasonable terms and conditions through all business and financial cycles.

201.0 Reference: Exhibit B1-15, Response to BC Utility Customers IR No. 1 to Ms. McShane,

Question 4.4, p. 11

Deemed Preferred Shares

The Response to BC Utility Customers IR question 4.4 states that Gaz Métro has a 38.5% common equity ratio, but Régie has also allowed Gaz Métro a 7.5% deemed preferred shares, i.e., the company does not have any real preferred shares outstanding that create a financial obligation to the utility. Ms. McShane also states that effectively, with no real preferred shares, Gaz Métro is allowed a higher common equity ratio than the 38.5% common equity ratio in isolation indicates.

In Exhibit B-20, response to BCUC IR No. 1, Question 14.6, Mr. Engen commented that preferred shares would not be an appropriate alternative for common equity, as preferred equity simply creates more financial risk from the perspective of the common equity holder and raises the cost of common equity.

201.1 Would Ms. McShane describe how Gaz Métro is allowed to recover the deemed costs of preferred equity?

Response:

The cost of the deemed preferred shares is treated from a revenue requirements perspective in the same manner as the deemed common equity. The utility is deemed to have issued preferred shares annually in an amount necessary to maintain preferred shares at 7.5% of rate base. Each new deemed "issue" of preferred shares is assigned a market rate, which remains fixed. As with the common equity return, the deemed preferred return attracts an income tax allowance.

201.2 Please comment how the deemed preferred share of Gaz Métro is treated by credit agencies.

Response:

There is no treatment given the deemed preferred shares by the credit rating agencies. The credit rating agencies look at the actual capital structure maintained by the entities that are being rated. DBRS rates the debt of Gaz Métro Inc. ("GMI"), the general partner of Gaz Métro LP ("GMLP"). GMI raises the debt, loans it to GMLP on the same terms and conditions, and GMLP guarantees the debt obligations of GMI. The DBRS rating of GMI is based on the credit quality of GMLP, which holds the Québec gas distribution utility assets. DBRS refers in passing to the 7.5% deemed preferred share component of the regulated Québec gas distribution operations of GMLP. However, since there are no actual preferred shares in the GMLP capital structure, there is no reason to attribute any treatment to them.

201.3 Is Mr. Engen's opinion on the inappropriateness of preferred shares as alternative to common equity limited to actual offering of preferred shares? Or does his opinion extend to deemed preferred shares?

Response:

The preamble to the question incorrectly attributes the response to BCUC IR 1.14.6 to Mr. Engen. BCUC IR 1.14.6 was addressed to the FBCU and was responded to by the FBCU. As noted in BCUC IR 1.14.6, the FBCU do not believe that preferred equity is an appropriate alternative to common equity. With respect to deemed preferred shares, the FBCU do not believe it appropriate to lower the common equity component by replacing common equity with deemed preferred shares. As there would be no real preferred shares issued by the company, any reduction in deemed common equity would entail a reduction in the actual common equity ratio maintained by the company and a corresponding increase in the debt ratio, as it would be punitive to fund deemed preferred shares with actual common equity. The company's actual capital structure, on which credit ratings are based, would be weaker as would credit metrics, as not only would there be reduced cash flows from deemed preferred shares relative to common equity, but there would be increased interest expense from the real debt that would need to be issued to replace the lower deemed common equity. For a utility like FEI whose credit metrics are already considered weak for its credit rating, it would not be appropriate to deem preferred shares in place of common equity.

202.0 Reference: Exhibit B1-15, Response to BC Utility Customers IR No. 1, Question 5.5, p. 14

Canadian business and regulatory environments

Ms. McShane quotes Moody's: "We view Canada's business and regulatory environments as being more supportive than many of those in the U.S."

202.1 Would Ms. McShane explain why Moody's holds this view?

Response:

Ms. McShane cannot speak for Moody's. However, based on what Moody's has said, Moody's conclusion that the Canadian business and regulatory environments are more supportive appears to reflect its view that state regulation in the U.S. is more fragmented than national regulation; i.e., U.S. utilities are subject to overlapping or unclear regulatory jurisdiction, U.S. power markets are volatile and state regulation can become political. However, it should be noted that Moody's views the evaluation of a utility's regulatory framework as company specific, stating:

"It is important to note that our evaluation of a utility's regulatory framework is company specific, considering each company's experience and track record at cultivating supportive regulatory relationships and operating within its framework. Although utilities operating within the same framework will tend to have similar Factor 1 scores, it is possible to have deviations based on actual experience." (*Special Comment: Regulatory Frameworks - Ratings and Credit Quality for Investor-Owned Utilities Evaluating a Utility's Regulatory Framework*, June 18, 2010, page 13)

202.2 Shouldn't Canadian regulators therefore continue to award lower ROEs to Canadian utilities?

Response:

Ms. McShane provides the following response.

No. Canadian regulators should be awarding a fair ROE, which should be determined based on the returns available from comparable risk investments. Although the returns allowed in other jurisdictions may be a useful check, the estimation of the fair ROE should be made independently from what is allowed elsewhere. As regards Moody's views of relative regulatory risk, its June 2010 report cited above says "We view Canada's business and regulatory environments as being more supportive than many of those in the U.S." In Ms. McShane's opinion, that statement means that Moody's considers that there are regulatory jurisdictions in the U.S. that it would view as similarly supportive as those in Canada, and, by extension, that there are U.S. utilities that are of comparable regulatory risk to Canadian utilities. Moreover, it is not sufficient to find that particular U.S. utilities are of higher regulatory risk than Canadian utilities to conclude that they are of higher equity risk than Canadian utilities. The impact of financial risk, e.g., the capital structure, is an important component of the total risk. It is the total risk, business, regulatory and financial risk that determines the cost of equity. U.S. utilities generally and the U.S. utilities in Ms. McShane's sample specifically have significantly higher equity ratios than Canadian utilities generally and FEI specifically.

203.0 Reference: Exhibit B1-15, Response to BC Utility Customers IR No. 1, Question 12.7, p. 41

Beta

Ms. McShane is not aware of any Canadian utility samples that have raw betas of 0.65-0.70.

203.1 Wouldn't one expect raw betas to fluctuate above and below the 'real' beta of a firm?

Response:

As noted at footnote 97 (page 89) of Ms. McShane's testimony, the term "raw" means that the beta is a statistical calculation of the historical relationship between the price movements of a stock and the corresponding price movements of the market portfolio. If the term "real" beta is taken to simply refer to the longer-term relationship between the price movements of a stock and the corresponding price movements of market portfolio, then, yes, Ms. McShane would expect "raw" betas of individual companies to fluctuate around the "real" beta. However, the real issue is not whether individual companies' calculated betas deviate from those of other companies in the same industry over a particular period, or whether the calculated betas of an industry deviate from their long-term average. The real issue is whether the "raw" beta is a reasonable estimator of risk and a good predictor of expected or required returns. As Ms. McShane indicated at lines 1753 to 1757 of her testimony, "The objective of using the CAPM (as with any cost of equity model) is to estimate the returns that investors expect or require. Empirical tests of the model have shown in some cases that the model underestimates the returns for low beta stocks and overestimates them for high beta stocks and in other cases that there is no relationship between beta and return." Also please see footnote 114 at page 97 and pages A-18 to A-24 for further discussion of the issues related to using betas as a measure of risk for the purpose of estimating expected and required returns.

203.2 Why would raw betas of Canadian utilities always be lower than what Ms. McShane considers reasonable?

Response:

As noted in response to BCUC IR 2.203.1, the purpose of the CAPM is to estimate the returns that investors expect or require. There is significant empirical evidence that the CAPM underestimates returns for companies that have calculated (or "raw") betas materially lower than

1.0, as is the case with both Canadian (and U.S.) utilities. A reasonable risk adjustment factor needs to take account of that evidence.

203.3 Does this cast greater doubt on the validity of the CAPM?

Response:

Yes, as discussed at pages A-18 to A-24 of Ms. McShane's evidence.

204.0 Reference: Exhibit B1-15, Response to BC Utility Customers IR No. 1, Question 14.8, p. 47

Comparable earnings

Ms. McShane states there are no instances other than BCUC in 2009 where a Canadian board has given weight to the comparable earnings test in the past 10 years.

204.1 Please provide extracts from tribunal decisions over the past 10 years which explain the rationales for not giving weight to the comparable earnings test?

Response:

Extracts from tribunal decisions over the past 10 years which provide the rationales for not giving weight to the comparable earnings test are provided in Attachment 204.1. Extracts from the following decisions are included:

1. Alberta Energy and Utilities Board (EUB), Decision 2004-052, Generic Cost of Capital, July 2, 2004
2. Alberta Utilities Commission, Decision 2009-216, Generic Cost of Capital, November 12, 2009
3. Alberta EUB, Decision 2003-061, AltaLink Management Ltd. and TransAlta Utility Corp., Transmission Tariff, August 3, 2003
4. Public Utilities Board of the Northwest Territories, Decision 13-2007, Northwest Territories Power Corporation, August 29, 2007
5. British Columbia Utilities Decision, 2006 ROE Decision Terasen Gas *et al*, March 2, 2006

These decisions predated the Commission's 2009 ROE Decision, which did give some weight to the comparable earnings test.

205.0 Reference: Exhibit B1-16, Response to ICG IR No. 1, Question 1, p. 1

Cost of Capital

Mr. Engen states that in a more risk adverse market, one would expect the cost of capital to increase.

205.1 Does this apply to utilities where their P/E multiples have grown significantly against the P/E ratios of the TSX in recent years?

<u>Response:</u>

Please refer to the response to BCUC IR 2.153.1 for a clarification of the Canadian utilities group P/E ratio changes. Please refer to the response to BCUC IR 1.19.4.

205.2 In a risk adverse market wouldn't the relatively lower risk of low risk utilities see a relatively lower cost of capital compared to other companies?

<u>Response:</u>

Mr. Engen provides the following response.

It should, and it is manifest in the debt markets through lower spreads.

Attachment 165.1

Coastal Region
YE Accounts by rate class

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	534,987	538,473	541,959	545,472	549,001	552,082	555,041	557,952	560,779	563,553	566,249	568,930	571,518
Rate 2	54,558	55,021	55,484	55,954	56,430	56,829	57,207	57,574	57,929	58,277	58,608	58,939	59,251
Rate 3	4,242	4,305	4,376	4,447	4,518	4,582	4,641	4,699	4,756	4,813	4,867	4,921	4,975
Rate 4	33	33	33	33	33	33	33	33	33	33	33	33	33
Rate 5	221	221	221	221	221	221	221	221	221	221	221	221	221
Rate 6	26	26	26	26	26	26	26	26	26	26	26	26	26
Rate 7	1	1	1	1	1	1	1	1	1	1	1	1	1
Rate 22	22	22	22	22	22	22	22	22	22	22	22	22	22
Rate 23	1,126	1,131	1,136	1,141	1,146	1,148	1,149	1,150	1,151	1,152	1,153	1,154	1,155
Rate 25	488	488	488	488	488	488	488	488	488	488	488	488	488
Rate 27	81	81	81	81	81	81	81	81	81	81	81	81	81
Total Coastal Region	595,785	599,802	603,827	607,886	611,967	615,513	618,910	622,247	625,487	628,667	631,749	634,816	637,771

Annual Demand by Rate Class(TJ)

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	50,929	50,560	50,280	50,093	49,999	49,960	50,006	50,045	50,074	50,096	50,109	50,119	50,118
Rate 2	18,222	18,322	18,421	18,577	18,678	18,754	18,878	18,942	19,001	19,115	19,165	19,214	19,316
Rate 3	13,757	13,961	14,191	14,422	14,652	14,859	15,051	15,239	15,424	15,609	15,784	15,959	16,134
Rate 4	76	76	76	76	76	76	76	76	76	76	76	76	76
Rate 5	2,300	2,276	2,252	2,230	2,209	2,188	2,168	2,147	2,127	2,107	2,087	2,068	2,048
Rate 6	68	68	68	68	68	68	68	68	68	68	68	68	68
Rate 7	3	3	3	3	3	3	3	3	3	3	3	3	2
Rate 22	13,412	13,210	13,009	12,933	12,858	12,783	12,710	12,637	12,564	12,493	12,422	12,352	12,282
Rate 23	5,478	5,502	5,527	5,551	5,575	5,585	5,590	5,595	5,600	5,604	5,609	5,614	5,619
Rate 25	8,511	8,399	8,287	8,231	8,175	8,120	8,066	8,012	7,958	7,906	7,853	7,802	7,750
Rate 27	4,708	4,659	4,611	4,589	4,567	4,546	4,525	4,504	4,483	4,463	4,442	4,422	4,402
Total Coastal Region	**117,464**	**117,036**	**116,724**	**116,772**	**116,861**	**116,942**	**117,139**	**117,266**	**117,378**	**117,539**	**117,619**	**117,696**	**117,817**

Coastal Region
YE Accounts by rate class

Core	2025	2026	2027	2028	2029	2030
Rate 1	574,086	576,607	579,101	581,568	584,022	586,447
Rate 2	59,563	59,871	60,175	60,476	60,774	61,070
Rate 3	5,029	5,082	5,134	5,188	5,243	5,296
Rate 4	33	33	33	33	33	33
Rate 5	221	221	221	221	221	221
Rate 6	26	26	26	26	26	26
Rate 7	1	1	1	1	1	1
Rate 22	22	22	22	22	22	22
Rate 23	1,156	1,157	1,158	1,159	1,160	1,161
Rate 25	488	488	488	488	488	488
Rate 27	81	81	81	81	81	81
Total Coastal Region	640,706	643,589	646,440	649,263	652,071	654,846

Annual Demand by Rate Class('

Core	2025	2026	2027	2028	2029	2030
Rate 1	50,114	50,103	50,088	50,069	50,047	50,020
Rate 2	19,358	19,398	19,497	19,534	19,630	19,665
Rate 3	16,309	16,481	16,650	16,825	17,003	17,175
Rate 4	76	76	76	76	76	76
Rate 5	2,029	2,010	1,991	1,973	1,954	1,936
Rate 6	68	68	68	68	68	68
Rate 7	2	2	2	2	2	2
Rate 22	12,214	12,146	12,078	12,012	11,946	11,880
Rate 23	5,624	5,629	5,634	5,639	5,643	5,648
Rate 25	7,700	7,649	7,600	7,550	7,502	7,453
Rate 27	4,383	4,363	4,344	4,325	4,306	4,287
Total Coastal Region	**117,876**	**117,926**	**118,028**	**118,072**	**118,177**	**118,211**

FEVI

Year end accounts by Rate Class

Rate Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
RGS	96,379	99,199	102,086	105,095	108,187	110,640	112,820	114,956	117,025	118,942	120,876	122,857	124,704	126,541	128,370	130,174
SCS1	5384	5496	5611	5731	5855	5950	6032	6112	6187	6255	6324	6397	6461	6526	6591	6655
SCS2	1430	1435	1440	1446	1452	1455	1458	1461	1463	1464	1465	1467	1468	1469	1470	1471
LCS1	1375	1380	1385	1390	1396	1399	1402	1405	1407	1408	1409	1411	1412	1413	1414	1415
LCS2	541	546	551	557	563	567	570	573	575	577	579	581	583	584	585	586
AGS	891	896	901	906	911	915	918	921	923	925	927	929	931	933	935	937
LCS3	131	134	137	140	143	146	148	150	152	153	154	156	157	158	159	160
HLF	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
ILF	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Total	**106,145**	**109,100**	**112,125**	**115,279**	**118,521**	**121,086**	**123,362**	**125,592**	**127,746**	**129,738**	**131,748**	**133,812**	**135,730**	**137,638**	**139,538**	**141,412**

Annual Demand by Rate Class(TJ)

Rate Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
RGS	4,639	4,636	4,648	4,680	4,731	4,772	4,821	4,866	4,907	4,940	4,972	5,004	5,030	5,053	5,075	5,094
SCS1	627	640	653	667	682	693	702	712	720	728	736	745	752	760	767	775
SCS2	465	466	468	470	472	473	474	475	475	476	476	477	477	477	478	478
LCS1	1,347	1,352	1,357	1,362	1,368	1,371	1,374	1,377	1,378	1,379	1,380	1,382	1,383	1,384	1,385	1,386
LCS2	1,342	1,355	1,367	1,382	1,397	1,407	1,414	1,422	1,427	1,432	1,437	1,442	1,447	1,449	1,452	1,454
AGS	1,122	1,128	1,134	1,141	1,147	1,152	1,156	1,160	1,162	1,165	1,167	1,170	1,172	1,175	1,177	1,180
LCS3	1,953	1,998	2,043	2,087	2,132	2,177	2,207	2,237	2,266	2,281	2,296	2,326	2,341	2,356	2,371	2,386
HLF	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118
ILF	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98

FEVI

Year end ac

Rate Class	2028	2029	2030
RGS	131,982	133,824	135,689
SCS1	6719	6784	6849
SCS2	1472	1473	1474
LCS1	1416	1417	1418
LCS2	587	588	589
AGS	939	941	943
LCS3	161	162	163
HLF	6	6	6
ILF	8	8	8
Total	**143,290**	**145,203**	**147,139**

Annual Dem

Rate Class	2028	2029	2030
RGS	5,112	5,130	5,147
SCS1	782	790	797
SCS2	478	479	479
LCS1	1,387	1,388	1,389
LCS2	1,457	1,459	1,461
AGS	1,182	1,185	1,187
LCS3	2,401	2,416	2,430
HLF	118	118	118
ILF	98	98	98

INL
YE Accounts by rate class

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	214,124	216,385	218,644	220,977	223,349	225,218	226,945	228,619	230,218	231,776	233,285	234,812	236,280
Rate 2	21,059	21,287	21,515	21,750	21,986	22,170	22,339	22,500	22,654	22,800	22,941	23,083	23,217
Rate 3	793	824	855	887	921	949	976	1,003	1,028	1,053	1,079	1,106	1,132
Rate 4	12	12	12	12	12	12	12	12	12	12	12	12	12
Rate 5	28	28	28	28	28	28	28	28	28	28	28	28	28
Rate 6	2	2	2	2	2	2	2	2	2	2	2	2	2
Rate 7	2	2	2	2	2	2	2	2	2	2	2	2	2
Rate 22	17	17	17	17	17	17	17	17	17	17	17	17	17
Rate 23	232	236	240	244	248	251	254	257	260	263	266	269	272
Rate 25	86	86	86	86	86	86	86	86	86	86	86	86	86
Rate 27	14	14	14	14	14	14	14	14	14	14	14	14	14
Total	236,369	238,893	241,415	244,019	246,665	248,749	250,675	252,540	254,321	256,053	257,732	259,431	261,062

INL Annual Demand by Rate Class(TJ)

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	15,313	15,171	15,067	15,007	14,989	14,980	15,004	15,023	15,036	15,045	15,050	15,054	15,054
Rate 2	5,897	5,939	6,003	6,047	6,112	6,141	6,188	6,210	6,230	6,270	6,286	6,325	6,338
Rate 3	2,626	2,728	2,831	2,937	3,049	3,142	3,232	3,321	3,404	3,486	3,573	3,662	3,748
Rate 4	115	115	115	115	115	115	115	115	115	115	115	115	115
Rate 5	375	372	368	364	361	358	354	351	348	345	341	338	335
Rate 6	7	7	7	7	7	7	7	7	7	7	7	7	7
Rate 7	4	4	4	4	4	4	4	3	3	3	3	3	3
Rate 22	10,235	9,534	8,833	8,830	8,827	8,825	8,822	8,819	8,816	8,814	8,811	8,808	8,806
Rate 23	1,259	1,280	1,302	1,324	1,345	1,362	1,378	1,394	1,411	1,427	1,443	1,459	1,476
Rate 25	3,066	3,048	3,029	3,018	3,006	2,995	2,984	2,973	2,962	2,952	2,941	2,931	2,920
Rate 27	637	627	616	613	610	608	605	602	600	597	594	592	589
INL total	**39,533**	**38,824**	**38,174**	**38,265**	**38,427**	**38,535**	**38,692**	**38,819**	**38,932**	**39,061**	**39,165**	**39,295**	**39,392**

INL
YE Accounts by rate class

Core	2025	2026	2027	2028	2029	2030
Rate 1	237,724	239,139	240,551	241,922	243,332	244,744
Rate 2	23,353	23,485	23,615	23,739	23,869	24,000
Rate 3	1,160	1,186	1,212	1,239	1,267	1,295
Rate 4	12	12	12	12	12	12
Rate 5	28	28	28	28	28	28
Rate 6	2	2	2	2	2	2
Rate 7	2	2	2	2	2	2
Rate 22	17	17	17	17	17	17
Rate 23	275	278	281	283	286	289
Rate 25	86	86	86	86	86	86
Rate 27	14	14	14	14	14	14
Total	262,673	264,249	265,820	267,344	268,915	270,489

INL Annual Demand by Rate Cl

Core	2025	2026	2027	2028	2029	2030
Rate 1	15,051	15,045	15,037	15,026	15,017	15,006
Rate 2	6,375	6,388	6,423	6,433	6,468	6,480
Rate 3	3,841	3,927	4,013	4,102	4,195	4,288
Rate 4	115	115	115	115	115	115
Rate 5	332	329	326	323	320	317
Rate 6	7	7	7	7	7	7
Rate 7	3	3	3	3	3	3
Rate 22	8,803	8,801	8,798	8,796	8,793	8,791
Rate 23	1,492	1,508	1,524	1,535	1,552	1,568
Rate 25	2,910	2,900	2,890	2,880	2,870	2,860
Rate 27	587	584	582	579	577	575
INL total	**39,516**	**39,607**	**39,719**	**39,800**	**39,917**	**40,009**

COL
YE Accounts by rate class

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	20,853	21,054	21,256	21,463	21,670	21,862	22,085	22,260	22,433	22,565	22,691	22,816	22,951
Rate 2	2,153	2,182	2,211	2,243	2,274	2,305	2,340	2,370	2,398	2,420	2,440	2,459	2,479
Rate 3	89	92	95	99	102	105	109	111	113	115	117	119	122
Rate 4	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 5	4	4	4	4	4	4	4	4	4	4	4	4	4
Rate 6	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 22	7	7	7	7	7	7	7	7	7	7	7	7	7
Rate 23	17	17	17	17	17	17	17	17	17	17	17	17	17
Rate 25	7	7	7	7	7	7	7	7	7	7	7	7	7
Rate 27	2	2	2	2	2	2	2	2	2	2	2	2	2
Total Region	23,132	23,365	23,599	23,842	24,083	24,309	24,571	24,778	24,981	25,137	25,285	25,431	25,589

COL Annual Demand by Rate Class(TJ)

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	1,630	1,616	1,606	1,600	1,598	1,599	1,607	1,611	1,614	1,615	1,615	1,615	1,615
Rate 2	687	696	703	711	721	728	739	747	753	760	764	767	773
Rate 3	318	329	339	354	364	375	389	396	404	411	418	425	436
Rate 4													
Rate 5	37	37	36	36	36	35	35	35	34	34	34	33	33
Rate 6													
Rate 7	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 22	2,530	2,477	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424	2,424
Rate 23	77	77	77	77	77	77	77	77	77	77	77	77	77
Rate 25	213	209	206	205	205	204	204	203	203	202	201	201	200
Rate 27	18	18	18	18	18	18	18	18	18	18	18	18	18
Total	**5,510**	**5,459**	**5,410**	**5,426**	**5,443**	**5,462**	**5,494**	**5,511**	**5,527**	**5,541**	**5,551**	**5,560**	**5,577**

COL
YE Accounts by rate class

Core	2025	2026	2027	2028	2029	2030
Rate 1	23,053	23,158	23,254	23,285	23,306	23,326
Rate 2	2,493	2,510	2,525	2,527	2,528	2,528
Rate 3	124	126	128	129	129	129
Rate 4	0	0	0	0	0	0
Rate 5	4	4	4	4	4	4
Rate 6	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0
Rate 22	7	7	7	7	7	7
Rate 23	17	17	17	17	17	17
Rate 25	7	7	7	7	7	7
Rate 27	2	2	2	2	2	2
Total Region	25,707	25,831	25,944	25,978	26,000	26,020

COL Annual Demand by Rate C

Core	2025	2026	2027	2028	2029	2030
Rate 1	1,613	1,611	1,608	1,601	1,593	1,585
Rate 2	775	781	783	781	781	779
Rate 3	443	450	457	461	461	461
Rate 4						
Rate 5	33	32	32	32	31	31
Rate 6						
Rate 7	0	0	0	0	0	0
Rate 22	2,424	2,424	2,424	2,424	2,424	2,424
Rate 23	77	77	77	77	77	77
Rate 25	200	199	199	198	198	197
Rate 27	18	18	18	18	18	18
Total	**5,583**	**5,593**	**5,598**	**5,592**	**5,584**	**5,572**

FTN

YE Accounts by rate class

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	1,951	1,957	1,963	1,968	1,973	1,976	1,980	1,983	1,988	1,992	1,997	2,002	2,008
Rate 2(2_1)	419	421	423	425	427	428	429	430	432	434	436	438	440
Rate 3(2_2)	28	28	28	28	28	28	28	28	28	28	28	28	28
Rate 4	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 5	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 6	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 22	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 23	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 25	2	2	2	2	2	2	2	2	2	2	2	2	2
Rate 27	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,400	2,408	2,416	2,423	2,430	2,434	2,439	2,443	2,450	2,456	2,463	2,470	2,478

Annual Demand by Rate Class(TJ)

Core	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	263	262	261	261	260	260	259	259	259	258	258	258	258
Rate 2	191	192	191	191	191	190	190	189	189	189	189	189	188
Rate 3	94	94	94	94	94	94	94	94	94	94	94	94	94
Rate 4	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 5	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 6	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 22	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 23	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate 25	50	50	50	50	50	50	50	50	50	50	50	50	50
Rate 27	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**599**	**598**	**597**	**596**	**595**	**594**	**593**	**592**	**592**	**592**	**591**	**591**	**590**

FTN

YE Accounts by rate class

Core	2025	2026	2027	2028	2029	2030
Rate 1	2,015	2,023	2,033	2,042	2,052	2,062
Rate 2(2_1)	443	446	450	453	457	461
Rate 3(2_2)	28	28	28	28	28	28
Rate 4	0	0	0	0	0	0
Rate 5	0	0	0	0	0	0
Rate 6	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0
Rate 22	0	0	0	0	0	0
Rate 23	0	0	0	0	0	0
Rate 25	2	2	2	2	2	2
Rate 27	0	0	0	0	0	0
Total	2,488	2,499	2,513	2,525	2,539	2,553

Annual Demand by Rate Class

Core	2025	2026	2027	2028	2029	2030
Rate 1	258	258	259	259	260	260
Rate 2	189	189	189	190	191	191
Rate 3	94	94	94	94	94	94
Rate 4	0	0	0	0	0	0
Rate 5	0	0	0	0	0	0
Rate 6	0	0	0	0	0	0
Rate 7	0	0	0	0	0	0
Rate 22	0	0	0	0	0	0
Rate 23	0	0	0	0	0	0
Rate 25	50	50	50	50	50	50
Rate 27	0	0	0	0	0	0
Total	**591**	**592**	**592**	**593**	**594**	**595**

FEW

Year end accounts by Rate Class

Rate Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SGS-1/2 RES	2,341	2,366	2,396	2,426	2,455	2,478	2,498	2,520	2,538	2,555	2,572	2,586	2,599	2,612	2,624	2,638	2,650	2,662	2,673
SGS-1/2 COM	178	181	184	187	190	192	194	196	198	200	202	203	204	205	206	207	208	209	210
LGS-1 COM	85	85	86	86	87	87	88	88	89	89	90	90	91	91	92	92	93	93	94
LGS-2 COM	52	53	53	53	53	54	54	54	54	55	55	55	55	56	56	56	56	57	57
LGS-3 COM	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
NGV																			

Annual Demand by Rate Class(TJ)

Rate Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SGS-1/2 RES	193	195	197	200	202	204	205	207	209	210	211	213	214	215	216	217	218	219	220
SGS-1/2 COM	45	45	46	47	48	48	49	49	50	50	51	51	51	51	52	52	52	52	53
LGS-1 COM	101	101	102	102	103	103	104	104	105	105	107	107	108	108	109	109	110	110	111
LGS-2 COM	127	130	130	130	130	132	132	132	132	135	135	135	135	137	137	137	137	139	139
LGS-3 COM	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
NGV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Interior Region Volume (TJs)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2010 LTRP	**45,642**	**44,882**	**44,181**	**44,287**	**44,466**	**44,591**	**44,779**	**44,922**	**45,051**	**45,193**
Attachment 44.1										
INL	39,510	38,795	38,139	38,223	38,379	38,479	38,626	38,744	38,847	38,966
COL	5,504	5,451	5,400	5,414	5,431	5,448	5,478	5,494	5,509	5,521
FEFN	599	598	597	596	595	594	593	592	592	592
Interior Total	**45,613**	**44,844**	**44,136**	**44,234**	**44,405**	**44,521**	**44,698**	**44,830**	**44,948**	**45,079**
Variance	- 29	- 37	- 45	- 53	- 61	- 71	- 81	- 92	- 103	- 114
Variance as a %	-0.06%	-0.08%	-0.10%	-0.12%	-0.14%	-0.16%	-0.18%	-0.20%	-0.23%	-0.25%

2022	2023	2024	2025	2026	2027	2028	2029	2030
45,306	**45,446**	**45,559**	**45,690**	**45,791**	**45,910**	**45,985**	**46,095**	**46,176**
39,060	39,180	39,267	39,383	39,464	39,567	39,639	39,747	39,830
5,530	5,538	5,554	5,558	5,567	5,571	5,564	5,554	5,542
591	591	590	591	592	592	593	594	595
45,181	**45,310**	**45,411**	**45,532**	**45,622**	**45,731**	**45,796**	**45,895**	**45,967**
- 125	- 137	- 148	- 158	- 168	- 179	- 189	- 200	- 210
-0.28%	-0.30%	-0.32%	-0.35%	-0.37%	-0.39%	-0.41%	-0.43%	-0.45%

Attachment 165.1.2

4 MARKET TRENDS AND ENERGY FORECASTING

4.1 Introduction

A key stage in planning the future resource requirements for the Terasen Utilities is the development of customer and energy demand forecasts that provide insight into the amount of energy we need to provide and the load characteristics that our energy systems must be designed to meet. We must be able to acquire and deliver the total quantity of energy our customers will need throughout the year, adjusting for seasonal variations and changing market conditions. The primary design factor for system infrastructure and supply resources is the need to meet short term spikes in demand that are primarily weather driven. The forecasting process looks ahead over the planning horizon so that we are acting now to ensure we can cost effectively meet our customers' energy needs in the future.

Traditionally, the Utilities forecasting efforts have been focused on natural gas customer and demand outlooks to support supply, infrastructure and financial planning. Our traditional natural gas customer and demand forecast remains a primary function and are based on long standing methodologies that have been examined by stakeholders and evaluated and accepted by the Commission through numerous regulatory review processes. These traditional, accepted methodologies continue to underpin the examination of natural gas resource needs for the Utilities. Section 4.2 describes the methodologies used to develop our traditional demand forecast and provides an update on the natural gas customer and demand outlook over the 20 year planning horizon.

The Terasen Utilities have also now embarked on a broad range of new, alternative energy solutions to help customers manage both their energy costs and the environmental footprint of their energy demand. We have therefore identified a need to develop new ways to forecast energy demand for this wide range of customer end-use alternatives. Implementing renewable thermal energy alternatives, enhanced energy efficiency and conservation programs, and low carbon transportation fuel solutions will have an impact over time on demand and required infrastructure for conventional natural gas and electricity service. These new initiatives will also have infrastructure and other resource requirements that need to be met as their market penetration and demand grows. While these initiatives are not expected to have a marked impact on conventional energies in the short term, the Utilities expect to see a growing rate of change in customer behaviour, energy choice and energy consumption. Today, the Utilities are in the process of developing new methodologies to accommodate the shifting trends we expect to see emerging.

Section 4.3 examines new forecast methodologies that we are developing to capture the changing nature of energy choices available to our customers and the trends in energy consumption that we expect to see emerging over time. A new end-use focused approach to natural gas demand forecasting is examined that we believe will allow us to better capture and analyze the impact of changing customer choice and behaviour. Preliminary methodologies for forecasting growth and development of low carbon and renewable integrated energy solutions for communities are examined using residential application scenarios. Demand scenarios for new growth in natural gas vehicle fueling are also presented as part of our new forecasting initiatives for incorporating the Utilities low carbon and renewable energy solutions.

While we have initiated the development of these new methodologies and provide examples for discussion purposes, we have also identified where new data sources, further research and other resources are required in order to fully develop, validate and implement these forecasting initiatives. We expect to continue this development work over the next few years alongside the preparation of our traditional natural gas demand forecasts.

4.2 Traditional Natural Gas Demand Forecast

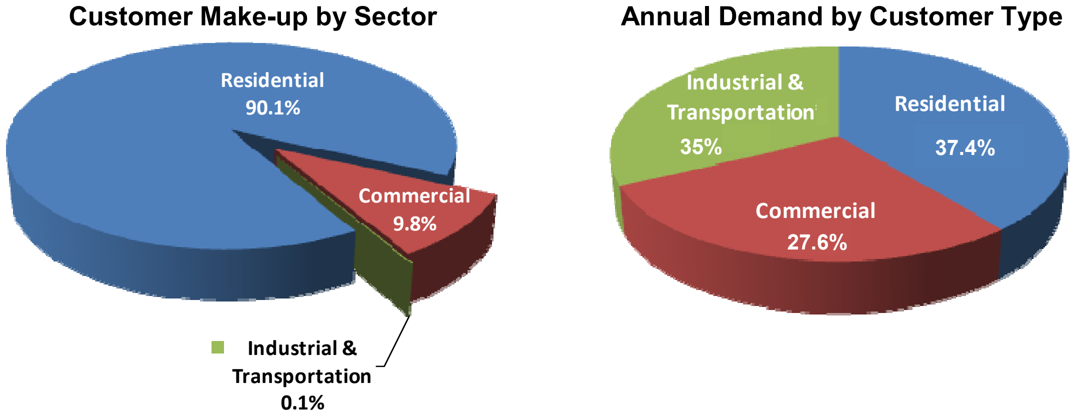
Two key elements that underpin the Terasen Utilities' resource planning activities are the traditional forecasts of annual demand and design day (also called peak day) demand for natural gas. The annual demand forecast represents the annual consumption by region and customer class and is used for gas supply contracting and rate setting purposes. The design day forecast provides an estimate of the maximum daily demand of natural gas that would be expected under extreme weather conditions, and is used for system and capacity planning as well as gas supply planning purposes. The Utilities' demand forecasts are used to ensure adequate system capacity, for the determination of gas supply resources and also to provide a base line against which to analyze the impact of proposed or potential future initiatives such as expanded energy efficiency and conservation activities or growth in natural gas sales for fueling transportation.

Inputs to the demand forecast include the analysis of historical data and trends from the Utilities' own systems, as well as many of the external factors discussed in Section 2. This section (Section 4.2) reviews the interplay of these factors in assessing future demand expectations and presents the annual and design day demand forecast results. Details regarding the demand forecast scenarios and results for each of the Terasen Utilities' service areas are provided in Appendices B-2 and B-3.

The Terasen Utilities customer base consists predominantly of residential customers who account for 90% of the overall customer base. However, on an annual demand basis, there is a relatively even split between customer groups which include residential, commercial and industrial / transportation[85] customers. The makeup of customer base and demand has implications on infrastructure requirements and conservation as discussed throughout this Resource Plan.

[85] Transportation customers in this case refer to customers who purchase their own natural gas supply and contract with the Terasen Utilities to transport that supply across our system.

Figure 4-1: Terasen Utilities' Customer and Demand Overview



4.2.1 MARKET TRENDS

Though identifying and investigating trends in historical data is an important part of forecasting the demand for natural gas, understanding the changes occurring in the marketplace and how they will impact the overall demand for energy is equally important. To that end, this section discusses market trends the Utilities have considered while developing its forecast of customer additions, average use per customer, annual demand, and also design day demand.

4.2.1.1 Population Growth

The most important trend to be considered when preparing the demand forecasts is the anticipated growth in population. Current projections from B.C. Stats estimate the province will add approximately 1.5 million new residents over the course of the next 20 years which will bring the current population of 4.5 million to 6.0 million by 2030. Population growth provides an indicator of the need for new housing and energy demand in B.C. and is one of the factors that inform provincial forecasts of household formations, housing starts and housing mix. These housing factors closely correlate to customer growth for the Terasen Utilities and thus provide key inputs into the customer forecast. The aggregate effect on the Utilities is expected to be an increase of approximately 150,000 customers over this same period, bringing the total number of customers to slightly above 1.1 million by the end of the planning period.

4.2.1.2 Residential Use Trends

Declining residential use per customer rates is a phenomenon affecting mature natural gas utilities across North America[86]. This same trend has been observed in most of the Terasen Utilities' service territories except TGW. For TGW, no discernable pattern has been identified, most likely due to the resort nature of the community and varying use patterns of land and homeowners and renters. The main drivers of this continuing decline include the renewal of

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[86] Residential Natural Gas Consumption, Heading Toward an Inflection Point. September, 2009. Cambridge Energy Research Associates Inc. 12p.

existing furnace stock, changes to building codes and standards, and also a shift in housing type from single family dwellings to multifamily dwellings. Upon identifying the main drivers and assessing the corresponding impact, the Terasen Utilities' forecasting methodologies in this Resource Plan reasonably forecast future residential average use per customer. Each of the main drivers is discussed in the following sections.

- **Renewal of Existing Furnace Stock**

The most significant driver of declining residential average use per customer in B.C. is the replacement of low-efficiency natural gas furnaces with higher efficiency models. Changes to the building code in 1990 mandated mid-efficiency furnaces as the minimum requirement for homes built since that time. Changes to building code legislation stipulated that high-efficiency furnaces be required for new construction as of 2008. For retrofit activity, the same minimum efficiency requirement was put in place as at December 2009.

In 2008, the Utilities conducted a Residential End Use Study ("2008 REUS" – see Appendix B-1) where residential customers were surveyed, with the primary goal being to understand how the Utilities' residential customers use energy in their homes. The survey included questions regarding the appliances present in homes and their respective efficiency ratings, housing type, and numerous other dwelling characteristics. Table 4-1 illustrates the estimated furnace efficiency shares by region that were derived from the 2008 REUS. Standard efficiency furnaces account for the largest proportion (45%) of gas furnaces still in use, followed by mid-efficiency furnaces (39%), and high efficiency furnaces (16%).

Table 4-1: Furnace Efficiency by Region (%)

Natural Gas or Piped Propane, 2008 REUS

Furnace Efficiency	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base*	297	513	231	72	113	1226	923	942
Standard efficiency (less than 78% AFUE)	52.1	38.0	19.0	20.7	29.2	45.0	47.0	54.5
Mid-efficiency (78% to 85% AFUE)	34.0	44.2	56.5	42.8	49.5	39.0	37.7	28.9
High efficiency (90% AFUE or higher)	13.9	17.7	24.5	36.5	21.2	16.0	15.3	16.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

* Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Table 4-2 summarizes the age profile for furnaces in use in the Terasen Utilities' five regions. Average furnace age varied from 10.1 years to 15.4 years depending upon the region. The average age of furnaces owned by our customers is 14 years. These types of characteristics, especially when monitored over time, provide a solid basis from which to estimate the impact of retrofit activity on natural gas appliances.

Table 4-2: Age of Furnace by Region

Natural Gas or Piped Propane, 2008 REUS

Age of Gas Furnace (years)	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	350	590	274	87	121	1422	1061	1500
Median	12.0	10.0	10.0	10.0	7.0	10.0	10.0	n/a
Mean	15.4	12.5	10.5	10.2	10.1	14.0	14.3	13.4
Standard deviation	21.0	8.7	3.8	0.9	1.6	12.0	13.8	n/a

This analysis of furnace age indicates a large portion of the standard efficiency furnaces will be retiring and be replaced with high efficiency furnaces in the coming years. This will have a significant impact on the Utilities' residential average use per customer, particularly in the Lower Mainland which has the largest customer base and the oldest stock of heating equipment among the Utilities service areas. Depending on the housing type and region, we estimate that a typical standard efficiency furnace consumes approximately 17 to 20 GJ[87] more per year than higher efficiency furnaces. A shift in the existing mix of furnaces from standard efficiency (currently the largest portion) to high efficiency will lead to a significant decrease in residential average use per customer.

Figure 4-2 illustrates the anticipated changes in furnace efficiency shares for single family dwellings in the Lower Mainland region[88]. Once standard efficiency furnaces are phased out from the Utilities' existing residential customer base, the rate of decline is expected to become more gradual. Based on the 2008 REUS, we estimate that standard efficiency furnaces will be completely phased out from its existing customer base sometime between 2017 and 2020 depending on the region. The Utilities estimate the decline in overall residential average use per customer from shifting furnace efficiency to be an approximate 2% per year for the next 3 to 5 years.

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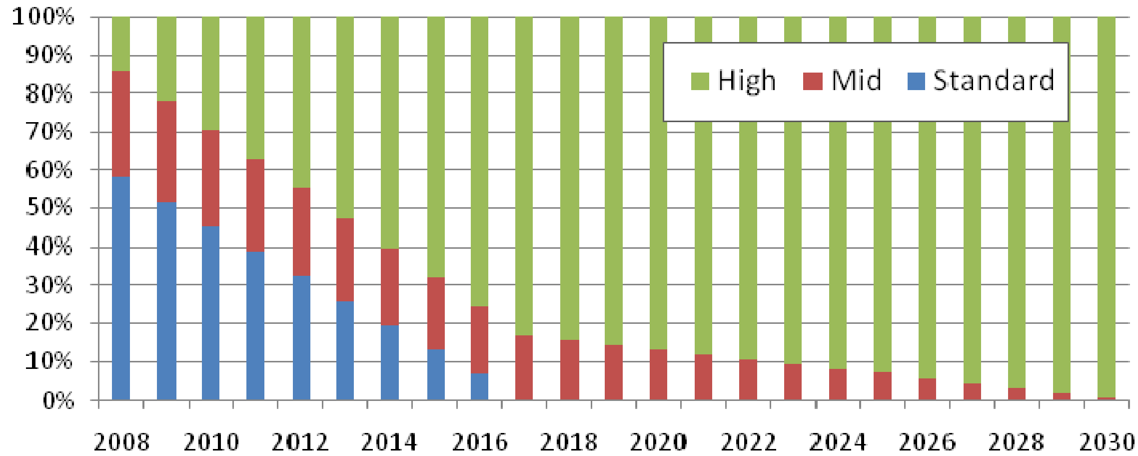
[87] Based on analysis from 2008 REUS.
[88] Based on the 2008 REUS assuming a maximum life of 30 years for standard efficient furnaces

Figure 4-2: Furnace Efficiency Share in Single Family Dwelling-LML

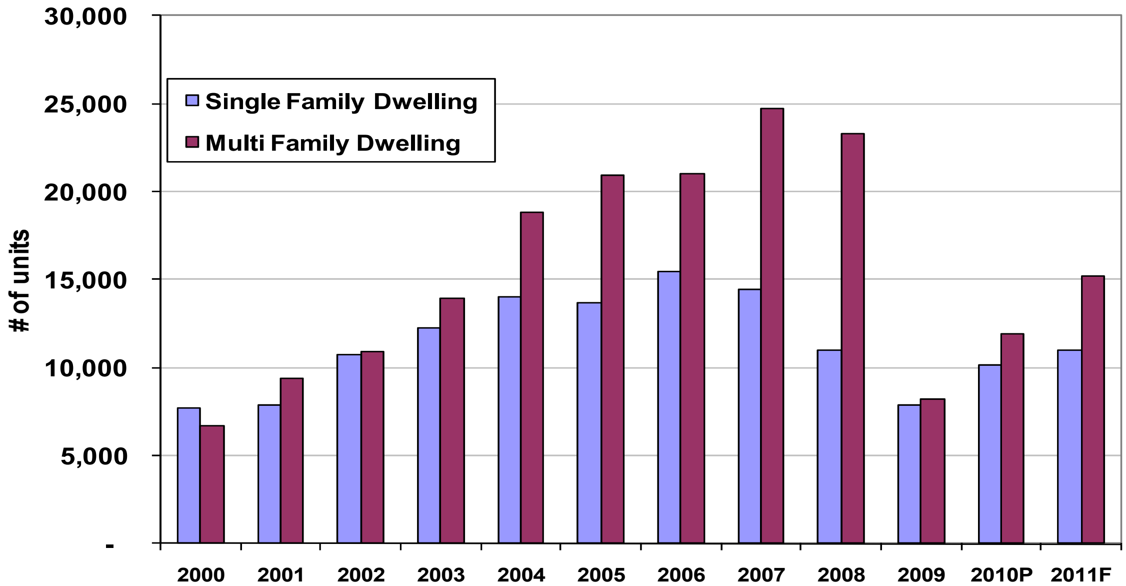


The Utilities anticipate that the last of the standard-efficiency furnaces will come out of service by 2017 for single family dwellings in this region based on replacement at the expected end of useful life of the asset. Although some customers may choose to increase maintenance costs for old equipment to avoid replacement costs, it is not unreasonable to assume that by 2030 all of the standard and mid-efficient furnaces in single family dwellings located in this region will have been replaced by high-efficiency technology. This type of analysis has been incorporated while estimating use per customer forecast for the 20 year planning period.

- **Shift in Housing Type**

Housing type is another factor impacting residential use per customer rates. Figure 4-3 shows the shift that has occurred over the past decade in the predominant housing type, from single family to multi-family dwellings. This continuing shift toward the multi-family housing type in B.C. is driven by affordability and limited availability of land for single family home construction. Canadian Mortgage and Housing Corporation ("CMHC") forecasts that the trend is expected to continue for 2010 and 2011. It is not unreasonable to assume that this pattern in housing type will continue for the foreseeable future.

Figure 4-3: B.C. Housing Starts – Mix of Housing Types



Source: CMHC

An analysis of 2009 customer data indicates that the Utilities were successful in bringing natural gas service to approximately 80%[89] of completed residential units (all types) reported by CMHC within the Utilities' service territories.

As a percentage of CMHC completions, the Utilities estimate that the vast majority (approx. 95%+) of SFDs installed natural gas service while 60 to 70% of MFD units completed were attached in some form; either with natural gas being piped to the individual units or serving some common application that benefits all residents of the housing complex. The challenge in assessing the level of penetration into the MFD markets lies in the fact that approximately 80% of the estimated attached MFD units are served by a single common meter. Situations where a common meter provides natural gas to an entire MFD building makes it difficult to determine how much of that consumption is attributable to individual suites as opposed to serving common loads.

This shift in new housing type has important implications for overall residential average use per customer. As illustrated in Figure 4-4 below, the average annual consumption for space heating purposes, regardless of energy type, is significantly lower for multifamily dwellings than for single family dwellings.

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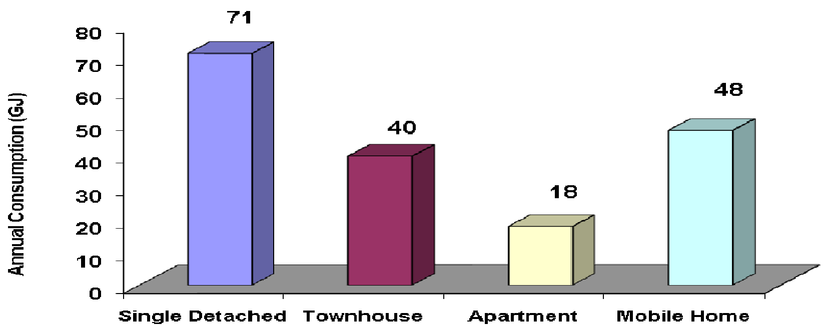
[89] Based on analysis from the Terasen Utilities' customer information system and validated with 2008 REUS results.

Figure 4-4: Space Heating Consumption – All Energy Types

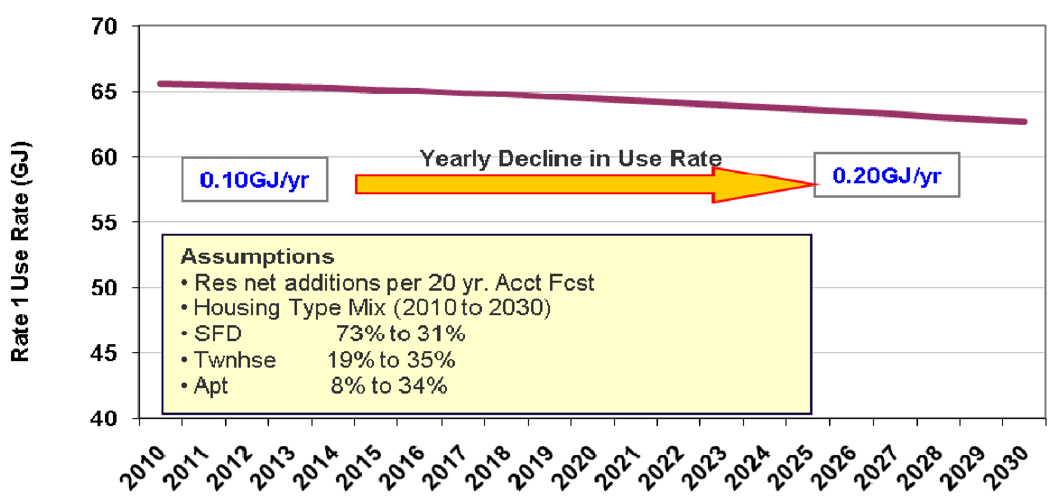


Source: NRCan

The impact of the continued dominance of multifamily dwellings in the housing market is an estimated decline in residential average use per customer by approximately 0.1 to 0.2 GJ per year. Figure 4-5 illustrates the estimated impact by gradually changing the mix of housing type while holding the typical average annual consumption per housing type and also annual customer additions constant.

It is important to note the values in this analysis are not meant to reflect forecasted values, but are chosen to gauge the independent impact a shift of housing types within the housing market has on the overall residential annual demand. Though not insignificant, the results suggest that housing type plays a considerably smaller role in declining residential usage rate than does the replacement of low-efficiency furnaces.

Figure 4-5: Impact of Shifting Housing Type on Use Rate for Space heating



4.2.2 NATURAL GAS COMPETITIVENESS

Section 2 discusses the competitive position of natural gas relative to other fuels and energy systems for home heating. That discussion includes consideration of natural gas rates (including the provincial Carbon Tax) compared to electricity (the main alternative to natural gas for this purpose in B.C.), furnace oil, propane and alternative energy systems. While rates are an important aspect of competitiveness, it should be recognized that other factors also play a role in energy choice, such as comfort and attitudes toward different fuel types.

Although much focus is placed on electricity in B.C. being a renewable energy source, opposition to the development of new infrastructure to meet growing electricity demand also continues to grab headlines. The Province's new Clean Energy Act does not promote the use of natural gas over electricity for thermal uses; neither does it preclude the use of natural gas over electricity, recognizing the important role that both energy types play in meeting B.C.'s energy and resource needs. The Utilties' initiative to acquire biogas resources and spur the growth of this new industry will also be seen in a favourable light and among energy consumers. This initiative may sway future decisions in favour of natural gas as supplies of this renewable energy source grow. Future attitudes to one of these energy types over the other remain uncertain, as both have important roles to play in a low carbon energy future.

The review of energy alternatives for space heating finds that natural gas remains at a similar level of competitiveness with respect to electricity as it has in recent years when factoring in the increases in carbon tax costs and the difference in upfront capital costs between electricity and natural gas heated homes. The competitive position of natural gas has improved, however against other carbon-based fuels. Recent technology developments that have made available unconventional sources of natural gas across North America previously thought to be economically unrecoverable, have resulted in a much more favourable outlook for the long term supply potential. For at least the short to medium term this is expected to support the natural gas competitive position of natural gas relative to other carbon based fuels.

On Vancouver Island, where many homes still use furnace oil, the advantage of natural gas has increased, making the case for conversions to natural gas more attractive. In the TGVI service area particularly, EEC programs are designed to incent customers to convert from oil to natural gas high efficiency furnaces. Similarly, the rate advantage for natural gas over propane has also grown, reinforcing the benefit of system conversion to natural gas for TGW customers. This advantage may also encourage the remaining propane users in proximity to gas lines in rural areas of the Province to convert. The position of natural gas against other carbon based fuels is also observed for vehicle transportation fuels (diesel and gasoline) as discussed in Section 2.1. The competitive position of natural gas against these carbon-based fuel alternatives is expected to help maintain growth in the demand for natural gas as a heating fuel in each of the Utilities' service areas, and support TGI's new natural gas vehicle initiatives[90].

The integrated, alternative energy solutions for thermal energy demand being implemented by the Terasen Utilities are expected to have only a small impact on natural gas demand initially, growing to a more substantial impact over the longer term. For these customers, costs are not the only consideration in making energy choices. More and more, customers with the means to do so are choosing more expensive installations for their thermal energy needs due to the perceived environmental benefits. These solutions are expected to be more widely adopted initially in district energy and larger multi-unit developments. The impact on natural gas demand of customers choosing alternative energy solutions is discussed further in Section 4.3.2

Natural gas is also expected to remain the preferred supplementary fuel for alternative energy systems due in part to the impact that this supplementary peak period demand would have on electricity infrastructure capacity needs and costs. The upfront capital costs for these systems are likely to remain prohibitive for many single family residential customers, moderating any early impact of individual alternative energy solutions on natural gas demand. The Terasen Utilities will continue to monitor the impact of alternative energy solutions on natural gas demand and adjust demand expectations accordingly.

4.2.3 COMMERCIAL USE RATE

Unlike the residential customer class, historic normalized use rates have been relatively stable across all commercial customer classes. The Utilities expect use rates to decline moderately in the short run but hold relatively constant in the long term. Going forward, as more customers engage in efficiency improvements and adopt alternative energy solutions, we expect use rates to trend downward. Until the point when additional data becomes available on the impact that expanded EEC programs and implementation of alternative energy systems have on future commercial use rates, the Utilities traditional forecasting methodologies in this LTRP are considered to reasonably forecast future commercial average use per customer.

For TGI, an added a level of rigor was included by identifying the top five consuming sectors within its commercial customer classes, and analyzing those sectors individually as part of the demand forecast. By analyzing historical consumption patterns on a sector by sector basis, and incorporating the latest available economic information, TGI is able to prepare a demand forecast that is consistent with the approach outlined in the 2009 Revenue Requirement Application (RRA). Reasonable assumptions with respect to future average use per customer were developed for each sector by analyzing historical trends in consumption and considering expected efficiency improvements based on currently planned Commercial EEC programs. This ultimately led to the development of the commercial average use per customer forecast.

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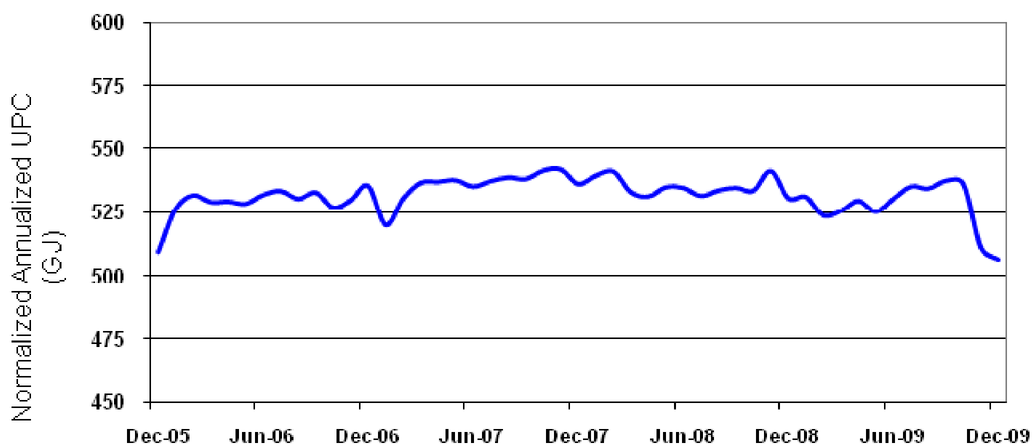
[90] Demand from TGI's new natural gas vehicle initiatives is not included in the traditional demand forecast – this demand is discussed separately in Section 4.3.3.

A detailed sector analysis for each small commercial (Rate Schedule 2), large commercial (Rate Schedule 3) and commercial transportation (Rate Schedule 23) as presented in the 2009 TGI RRA was carried out for this year's LTRP. The Utilities have demonstrated the analysis here by exemplifying the Apartment/Condo sector within the small commercial customer class.

Figure 4-6 illustrates the normalized annualized average use per customer over the period December 2005 through December 2009 for TGI's small commercial customers within the apartment/condo sector. This customer segment represents multi-family dwellings, and also smaller apartment or condominium buildings. The historical trend in average use per customer has been relatively stable with a slight decline in 2009. Given the recent approval and development of commercial EEC programs, there are opportunities for efficiency improvements and TGI is expecting a moderate decline in average use per customer over the longer range period.

Figure 4-6: Normalized Annual Use Rate for Apartment / Condominium Customers



In considering the trends seen in the various sectors as illustrated above, TGI is projecting the demand to increase slightly in the short term and expected to stabilize in the longer term. This is because the declines in short term use per customer are offset by anticipated increases in customer additions. In the absence of industrial sector code for TGVI and TGW customers, a forecast was developed by analyzing historical information and trends in the market.

4.2.4 INDUSTRIAL AND TRANSPORTATION CUSTOMER DEMAND

Given the relatively small number of TGI industrial customers[91], a different approach in forecasting demand is favoured over the approach taken for both residential and commercial customers. The methodology behind forecasting industrial demand is typically derived from the

91 Industrial customer forecast is limited to TGI, as TGVI and TGW have no industrial customer classes.

following two sources, an annual customer information survey and sector analyses of historical consumption.

- **Customer Information Survey**

Typically, the primary source of information for the industrial energy forecast is the industrial customer survey, which historically has been conducted over the period May through July on an annual basis. However, in 2010 the survey will be conducted in the fall of 2010 to allow for more recent data to be incorporated into the Utilities next Revenue Requirement Applications, and therefore the survey results will be used as a secondary source of information to validate the sector analysis as described below.

- **Sector Analyses**

Consistent with the 2010/2011Revenue Requirement Application (RRA) and prior years, the historical consumption patterns of the customers in each of the top seven consuming sectors were analyzed and then used in conjunction with the latest available economic information to project future energy demand in each of those sectors. The results from the sector analysis were then amalgamated to arrive at an estimate of future demand by each industrial customer class.

Table 4-3 provides the 2009 energy consumption and percentage each industry represents out of the total. The seven sectors being individually analyzed represent two-thirds of the total industrial volumes, providing a reasonable basis from which to develop the industrial demand forecast. The “other” category, representing one-third of the total industrial volumes, is also analyzed separately and includes a number of smaller industries such as education, commercial buildings, hotels, and recreation centres.

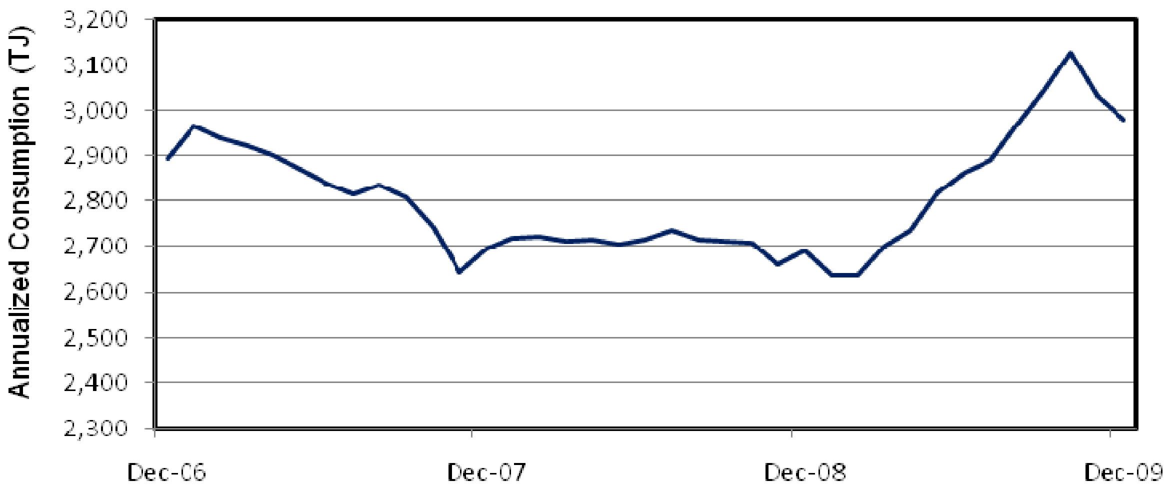
Table 4-3: Industrial Customers Top Energy Consuming Sectors

	PJ's	%
Pulp & Paper	12.4	24%
Wood Products	4.5	9%
Greenhouses	3.3	6%
Mining	2.5	5%
Apartment/Condo	3.4	7%
Chemical Manufacturing	3.4	7%
Food & Beverage	4.5	9%
Other	17.3	34%
Total	51.2	100%

Through sector analyses, TGI is also able to incorporate sector specific factors influencing demand for natural gas. For example, many customers in the greenhouse sector have fuel switching capabilities and are able to take advantage of changes in the spot market for energy prices, whereas those capabilities are not present in other sectors. Customers in the Apartment/Condo sector have opportunities for efficiency improvements available to them whereas customers in the wood products sector trend more closely to economic activity. Although these sector specific factors present additional challenges when developing the industrial demand forecast, incorporating them further adds to its reasonableness

A detailed sector analysis for the industrial customer class as presented in the 2010/2011 TGI RRA was carried out for this LTRP. The Utilities have demonstrated the approach taken to forecast industrial demand by taking examples from wood products and greenhouse sector.

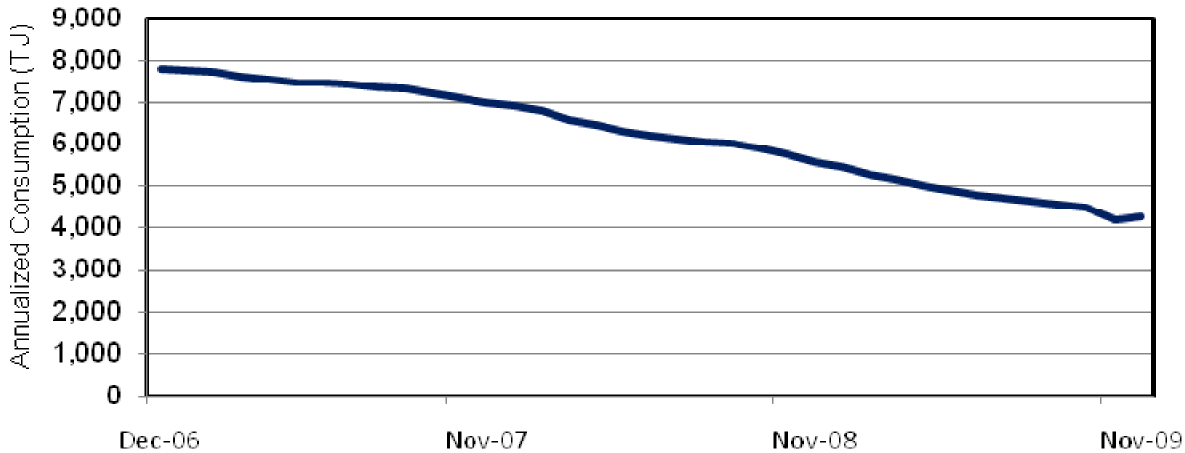
Figure 4-7: Annualized Consumption for the Greenhouse Sector



The Greenhouse sector (Figure 4-7) has seen both declines and increases in volumes since 2006. Although the more recent short-term trend is downward, there was significant growth experienced in this sector during 2008. This sector has the capability to switch between fuel sources, and therefore tends to respond to conditions in the spot market. Given that that the current development of North American shale gas has resulted in more favourable long term supply expectations relative to previous years, ', the Terasen Utilities are estimating that on average demand in this sector will remain stable throughout the forecast period.

The wood products sector, on the other hand, has been experiencing steadily declining volumes since early 2006. Figure 4-8 below illustrates this trend, and given the high level of dependence this sector has on the U.S. housing market, the Utilities anticipate a continued decline over the next few years, but stabilizing over the long-term.

Figure 4-8: Annualized Consumption for the Wood Products Sector



Through considering the trends seen in the various industrial sectors, as illustrated above, we are projecting a decline in overall demand over the forecast period based on best available information at this time.

- **Natural Gas Demand in B.C. for Electricity Generation and Vancouver Island Mills**

The discussion of annual and design day demand in this section does not include demand for Burrard Thermal Generating Station, the Island Co-generation Project or additional load from a potential new generating station in the Okanagan for meeting peak period electricity demand. Also not included in this discussion is demand from the Vancouver Island Gas Joint Venture mills. For capacity planning purposes, demand from these facilities is discussed in Section 6.1.

4.2.5 ALTERNATIVE FUTURE SCENARIOS

The Terasen Utilities forecast future customer additions and use per customer based on a range of possible future scenarios. As the forecast period increases, so do the levels of uncertainty which is why we vary the input assumptions from the reference case forecast to develop future scenarios. Two scenarios have been developed that illustrate the upper and lower range annual demand that would be expected to occur over the planning period based on a set of reasonable assumptions.

The scenarios described below for the traditional demand forecast do not incorporate the impact of new energy initiatives being undertaken by the Terasen Utilities. The potential impact of these initiatives is discussed in Section 4.3.2.

4.2.5.1 Robust Growth

The Robust Growth scenario is developed to illustrate the magnitude of additional consumption that could occur above the level set by the Reference Case, and also identifies the likely drivers that would lead to higher demand for natural gas. Although there are numerous factors that can affect consumption levels, the following items occurring concurrently are viewed as the main drivers in this scenario.

The province continues to recover from the economic downturn with growth beyond what is currently expected by the provincial Government and economists. Population migration from other provinces and immigration from other countries are greater than currently forecast, leading to greater population growth in the province. This increase in population growth is captured in higher rates of customer additions compared to the Reference forecast. The natural gas price advantage also improves with respect to electricity due to larger than expected increases in electricity rates while natural gas costs remain stable. Recognition by governments and society of the important role that natural gas can play in direct use applications to allow clean electricity exports to offset coal and natural gas fired generation in other jurisdictions could also put upward pressure on natural gas demand.

Though the forces affecting residential average use per customer are not expected to disappear under any scenario, the Robust Growth scenario envisions a situation where uses per customer rates stabilize sooner. This combined with stronger growth in population and improved capture rates in MFDs for residential customers, will support robust growth where the overall demand grows at a greater rate than for the reference case demand scenario.

For industrial customers the robust growth scenario is based upon a quicker than anticipated economic recovery in the sectors for the first two years followed by a period of stability. For example should the U.S. and world economies come out of recession sooner than expected, exports dependent sector such as the wood products, mining, chemical manufacturing and pulp and paper sectors could see higher demand than currently anticipated. At the same time, strong growth in provincial economy translates into higher demand for sectors such as apartments / condominiums and food and beverage manufacturing. The above factors have been taken into consideration while preparing the robust growth industrial demand scenario.

4.2.5.2 Low Growth

The Low Growth future scenario is developed to depict the lower bound in consumption with respect to the Reference case that could reasonably occur. The likely drivers that would lead to a lower demand for natural gas are identified and described in the following.

The province experiences weaker than expected economic growth driven by a U.S. economy that fails to recover from its recent economic downturn and in turn causes other closely linked economies, such as that in B.C. to slow. This would then manifest itself in terms of a slower rate of customer additions.

Technology advances and increasing efficiency improvements due to government regulations accelerate conservation efforts faster than what is currently anticipated. Natural gas heating equipment with standard efficiency for both space and water heating is replaced at an accelerated pace, and alternative technologies (e.g. solar thermal domestic hot water heating) begin to see broader acceptance in the market. These conditions would accelerate the decline in residential average use per customer.

As people seek to reduce the use of fossil fuels in order to minimize carbon emissions, the potential exists that the Utilities' existing customers may shift some or all of their heating loads to electricity in absence of end use policies that recognize the upward pressures that such activity will place on electricity infrastructure and regional GHG emissions. Customers with standard efficiency natural gas equipment, particularly might tend to make this switch. Though not necessarily achieving the desired outcome on a regional or global basis, confusion in the general population on how best to lower carbon emission could lead to both decreased use per customer rates and lower customer additions.

The next sections describe the main components of the Annual Demand forecast common to all three Terasen Utilities as well as additional trends that are impacting these forecast components. Details regarding the specific forecasts and scenarios for each of the Utilities are included in Appendix B-3.

4.2.5.3 Customer Additions

The customer additions forecast is derived from long-term provincial forecasts of household formations at the community level and validated against CMHC's nearer term forecasts in order to reflect the most current market situation. The forecast of customer additions is applied to both residential and commercial rate classes while no growth is assumed for industrial customers. The latest available economic analyses from the B.C. Government, major banks and other organizations are reviewed for consistency with the overall trend in household formations. For the forecast produced in support of the 2010 LTRP, the B.C. Statistics 2009 Household Formation Forecast (based on P.E.O.P.L.E. 34) was used to determine customer additions by area over the forecast period.

Commercial customer additions tend to reflect the same long-term growth patterns as those for residential customers, since growth in the business sector generally stems from growth in the population. This trend is captured in our forecast of commercial customer additions.

4.2.5.4 Use per Customer Rates Summary

The average usage, on a per customer basis, is one of the key components in estimating annual demand. The Utilities have developed a forecast of use per customer rates that forms a key input for use in long-term resource planning. The methodology to determine average use per customer for a given region and customer class as based on the following:

- Historical normalized consumption data
- Any known customer migration between rate classes
- Appliance retrofit activities and market trends
- Building codes and standards

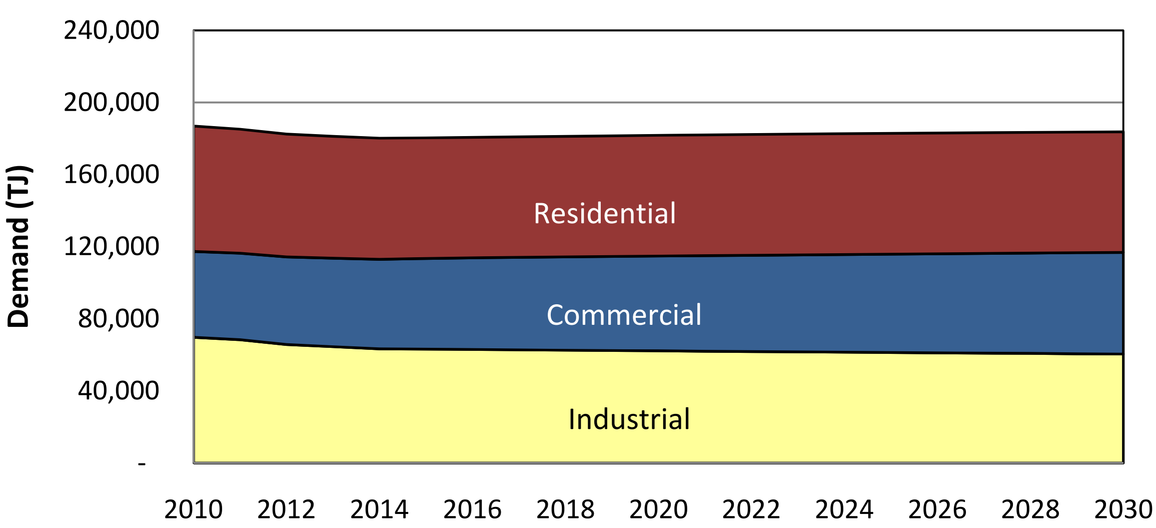
As discussed earlier, residential average use per customer for mature utilities, such as TGI have been experiencing declines since the early 1990s. A similar trend has been observed in TGVI in the last three years, while no discernable pattern has been identified for TGW. Based on recent analysis, the Utilities anticipate more rapid changes than what has been previously estimated. Declines of approximately 2% per year in residential average use per customer are now being forecast for the next 3 to 5 years, followed by more gradual declines over the planning period. The declines observed in the most recent historical normalized consumption data, expanded EEC programs coupled with various government regulations largely explain these declines in average use per customer. Other factors include current building codes mandating high efficiency furnaces for both new construction and retrofit hot water regulation with minimum efficiency of 0.6, the shift towards more multi-family dwellings in the housing mix, better insulated new homes and also the upgrading of existing homes.

4.2.6 ANNUAL DEMAND FORECAST RESULTS – ALL UTILITIES

4.2.6.1 Reference Case

On an aggregate basis across all utilities, overall consumption is forecast to remain relatively stable over the forecast period (Figure 4-9).

Figure 4-9: Reference Case Annual Demand Forecast 2010 - 2030 – All Utilities



The net increase in customer additions over the planning period is offset by a forecast decline in use per customer. Factors such as furnace replacement, building codes and standards, expanded EEC programs, and also the shift towards more multi-family homes in the housing mix work to drive down consumption on an individual basis, while the only factor contributing towards growth is an increase in the overall number of customers connected to the system. Commercial demand is expected to remain relatively stable while industrial demand is expected to stabilize within a few years.

4.2.6.2 Impact of EEC Programs on the Demand Forecast

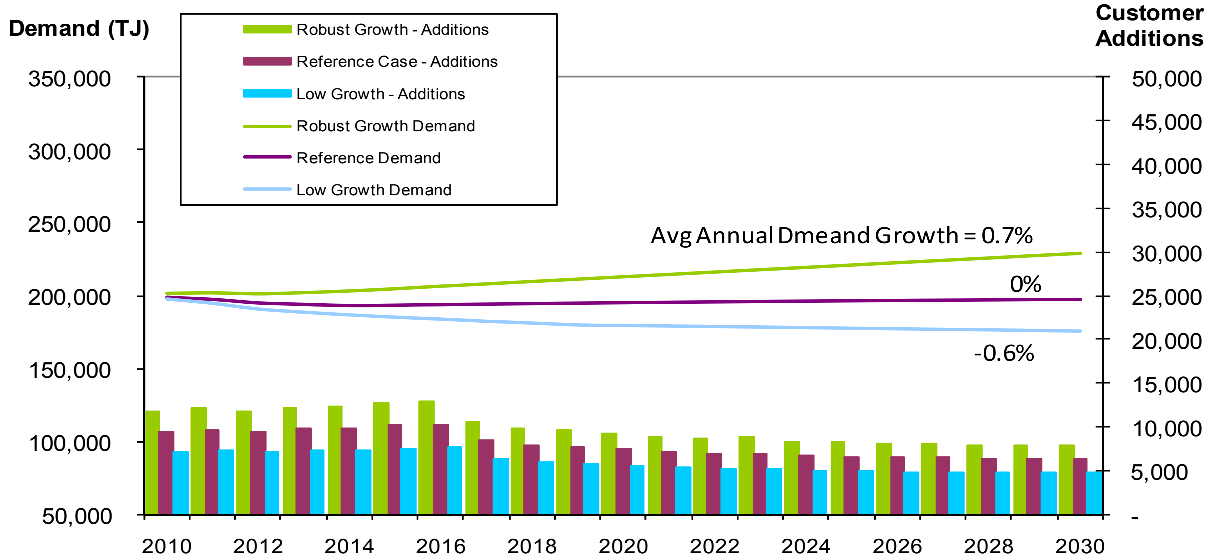
In June 2009, TGI and TGVI filed their 2010-2011 Revenue Requirements Applications, requesting approval from the Commission for an allocation of funding to be directed to new programs. The Commission approved the resulting Negotiated Settlement Agreement, which brings the total funding for EEC programs and initiatives to $72.3 million in 2010 and 2011. As the EEC funding will have a material impact on consumer behaviours further affecting demand, the current level of EEC funding is incorporated as part of building the reference demand forecast.

Section 5 discusses the potential impact on demand and GHG emissions involving different levels of future funding for EEC programs. These impacts are not incorporated here as those initiatives are still in planning stages. Once the Utilities receive approval for additional funding, and when CPR results become available, we would at that point incorporate the results into future demand forecasts.

4.2.6.3 Annual Demand – Robust Growth and Low Growth Scenarios

Figure 4-10 illustrates the Utilities' combined annual demand forecast for all three future scenarios. Appendix B-2 provides the annual demand details for each company separately.

Figure 4-10: Annual Demand and Customer Additions - All Utiliites



Under the robust growth forecast, it is anticipated that natural gas consumption could increase by approximately 0.7% per year, on average, to 220 PJ by 2030. Under this scenario, the province's population grows at a faster than anticipated rate and price signals result in customers switching heating loads more towards the direct use of natural gas in an effort to mitigate growth in electrical demand. It is important to note that increases in natural gas consumption would likely offset demand for other energy sources such as heating oil and electricity produced from fossil fuels.

A slight decline in annual demand materializes in the Low Growth scenario. This decline is contingent upon a markedly lower growth in population combined with aggressive conservation efforts and a shift towards other energy options for loads that have been traditionally served by natural gas. Under the Low Scenario, annual demand would decrease by approximately 0.5% per year, on average, to 170 PJ by 2030.

In summary, through analyzing the factors impacting demand for natural gas, incorporating the best available information when preparing the forecast, and by developing a number of scenarios, we have developed a long-term demand forecast that is both reasonable and appropriate for use in long-term resource planning.

4.2.7 DESIGN DAY DEMAND

Design day demand differs from annual demand in that it estimates the maximum daily consumption expected to occur during an unusually cold weather event. The forecast of design day demand is a crucial input into the Utilities' key activities of securing an adequate supply of natural gas and ensuring that the infrastructure is capable of delivering that natural gas where and when needed.

The determination of design day demand for the various regions is arrived at through a separate process than is the forecast of annual demand. The design day demand forecast is based upon two key inputs:

- The design day temperature; and
- The relationship between consumption and weather.

The design day temperature represents the coldest daily temperature that would be expected to occur once every twenty years. The relationship between consumption and weather is determined through regression analysis of historical daily consumption and historical daily temperature experienced over the past three years. Once this relationship is determined, the design day temperature is applied to it with the resulting design day demand per customer grossed up to reflect current customer counts. The methodology used to forecast design day demand is discussed in more detail in Appendix B-4 and remains consistent with previous years. In response to stakeholder feedback, the Utilities have undertaken a review of the regression models used to estimate the relationship between weather and consumption. The details of this review process are also described in Appendix B-4.

The design day demand forecasts for each of the Terasen Utilities is provided in Figures 4-11, 4-12 and 4-13 below. A modest growth in design day demand for each of the utilities is estimated for the current planning period which stems from modest growth in customer additions.

Figure 4-11: TGI Design Day Demand

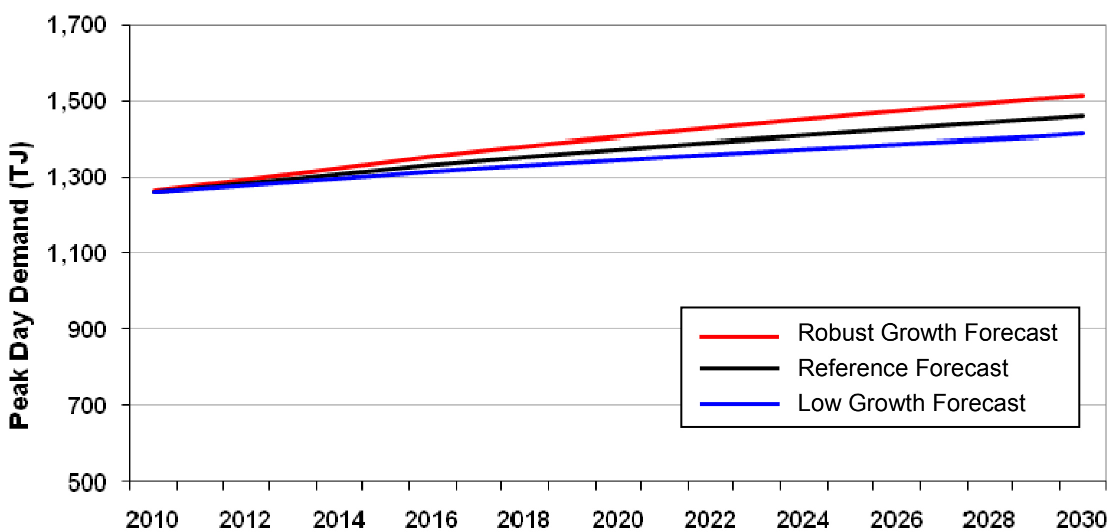


Figure 4-12: TGVI Design Day Demand

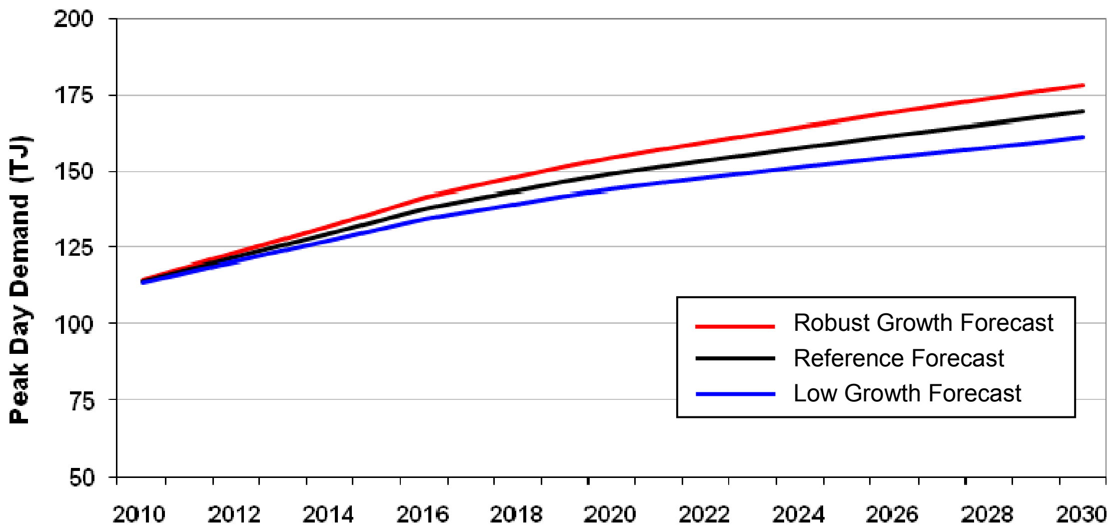
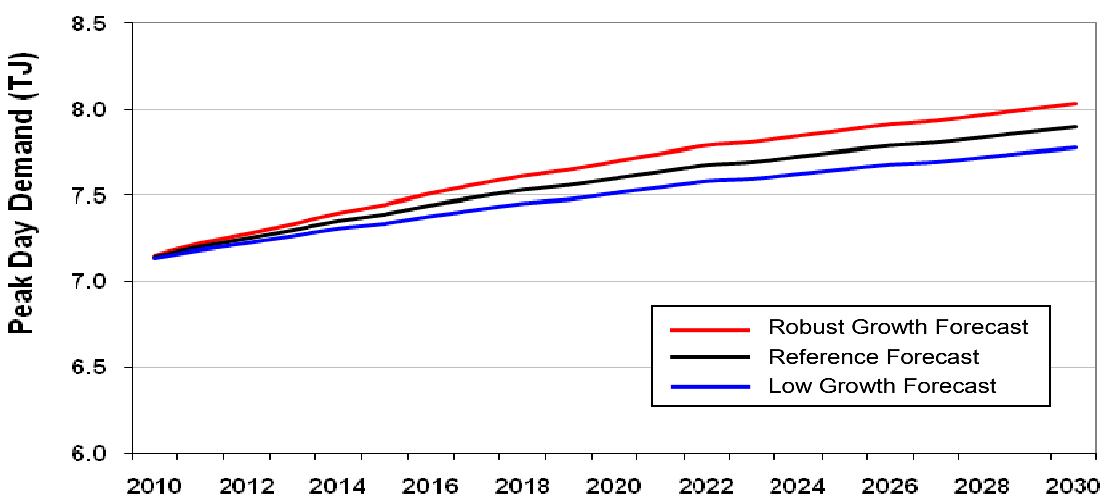


Figure 4-13: TGW Design Day Demand



The forecast of design day demand must be developed to meet expected customer demand during extreme cold weather. The consequences of under-forecasting could result in customers experiencing service interruptions at the most critical time. For this reason, and also considering that design day use per customer has remained relatively stable in recent years, design day use per customer is assumed to remain constant over the forecast period. The Terasen Utilities consider three years of historical data to ensure that actual changes in customer behaviour are reflected on an ongoing basis, but also to ensure any perceived trends resulting from short-term fluctuations in consumption are not projected onto future values. Additionally, impacts of climate change are not incorporated into the design day demand forecast. Although the overall global temperature may be trending upwards over time, and is expected to continue doing so, there is no certainty regarding the likelihood and severity of extreme weather events specific to the geographical area served by the Terasen Utilities.

By extensively analyzing the factors impacting the design day demand forecast, Terasen Utilities believe that the design day demand for this LTRP is appropriate and reasonable for infrastructure planning and gas supply contracting purposes. Going forward Terasen Utilities will continue to monitor the impact on design day demand from adoption of alternative energy stems and expanded EEC programs beyond 2011 and adjust demand expectations accordingly. The potential for increased adoption of alternative energy systems to impact design day demand is discussed in Section 4.3.2, where the development of new forecasting activities that will help determine if and when these new energy initiatives will impact existing natural gas use patterns is discussed.

4.3 New Forecasting Initiatives

4.3.1 PROPOSED NEW METHODOLOGY FOR NATURAL GAS DEMAND (RESIDENTIAL)

The Terasen Utilities expect the energy use patterns of new residential customers will evolve from that of the existing customer base today. The growing pace of change in energy policy, technology options, efficiency advancements, housing mix, customer behaviour, customer attitudes and other factors need to be addressed for each of these customer groups as part of forecasting demand for both natural gas and alternative energy solutions. For these reasons, the Utilities are adopting an end-use natural gas demand forecasting methodology that complements and may in the future replace its current natural gas demand forecasting approach. This new methodology is under development and not yet ready to be used for planning purposes. Where the Terasen Utilities' current forecasting methodology examines use rates within the residential customer service classes and applies future assumptions about these use rates to existing and new customers alike, our new approach will allow better consideration of differences in behaviours and future energy decisions between new and existing customers.

Given that the existing customer base is so large, it will continue to have the most significant impact on residential energy demand. However, as new customers have a much broader range of energy type and technology choices to choose from, they will have a growing and changing impact on future natural gas demand.

The type of energy technology solutions chosen and over all energy consumption is also expected to reflect differences in housing type. While the Utilities are not shifting the methodology by which we forecast total natural gas customer additions, the proposed methodology does include a break out of existing customers and new customer additions by housing type within the analysis of future demand. At this time, this breakout is limited to single family dwellings and townhouse type multi-family dwellings.

The Terasen Utilities' proposed new approach incorporates customer end use data such as the type of appliance broken out by end uses (space heating, water heating etc), housing type and region separated by existing and new customers. This revised approach will allow for greater flexibility in determining possible outcome because inputs that are derived from studies and research can be modified and changed as customer energy solutions and behaviours evolve overtime. Appendix B-5 provides a full discussion of this new approach, using the example of new furnace and proposed water heater regulations to show how the annual demand characteristics for new customers could differ from annual demand for the existing customer base in the Lower Mainland.

The example considers that new construction, where a natural gas furnace is installed for space heating, must use a high efficiency furnace to remain in compliance with building codes and standards. These new customers will therefore all join the Utilities' customer base at a substantially different rate of use than that of the existing customer base. The existing customer base will shift use rates much more slowly as the existing stock of lower efficiency furnaces is switched out for high efficiency models over time, as existing furnaces reach the end of their service life. The results of this example are shown for space heating demand in Figure 4-14 for the existing customer group and Figure 4-15 for the new customer group.

Figure 4-14: Natural Gas Demand Forecast for Existing Residential Customer Space Heating

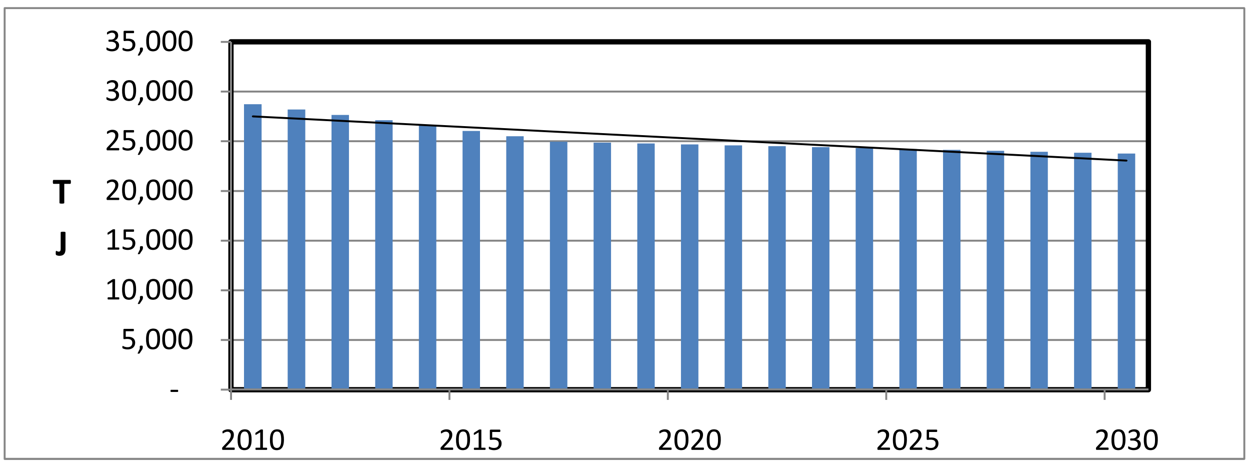
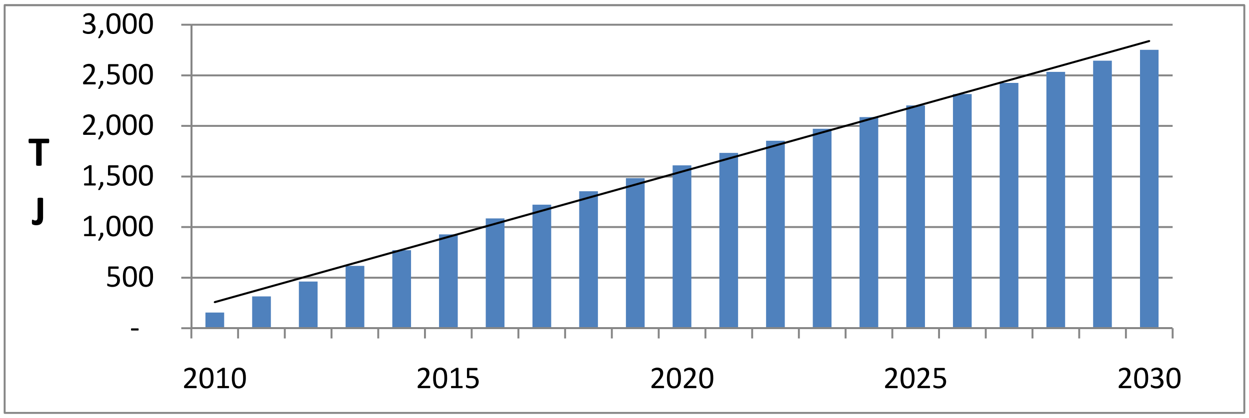


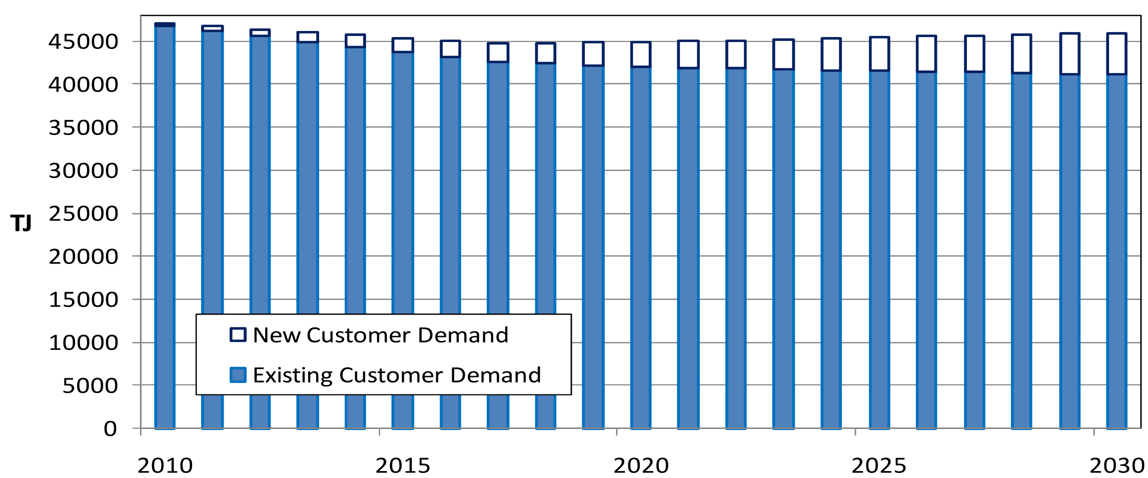
Figure 4-15: Natural Gas Demand Forecast for New Residential Customer Space Heating



Forecasting these two groups separately, and by end use will allow better consideration of the impact of new customer additions on over all annual and design day demand, and will allow the Utilities to better examine the impact, for example, of EEC programs that could speed the pace of furnace replacements among existing customers.

Figure 4-16 shows the resulting Lower Mainland Residential demand for all customers and for all end uses. While this graph shows how the above end-use analysis can get lost in the overall consumption totals, it also provides insights about where the Utilities might best focus their activities toward each of these customer groups. For example, this type of information can be used to help design energy efficiency and conservation programs.

Figure 4-16: Total Annual Natural Gas Demand Forecast for Lower Mainland Customers



Energy policy and technical ability to implement alternative, renewable thermal energy solutions are also examples of conditions that will impact new customers differently than existing customers. The current practice of multiplying average use rates by total customers within customer service classes will not permit the necessary analysis to fully examine the impacts of these conditions. An end-use approach with better consideration of new versus existing customers is needed.

Further research and analysis is required to more fully understand customers' changing behaviours, needs and energy decision making considerations, in order to employ this end use approach to demand forecasting across all service territories. While this new approach will be important for future energy planning, there remain gaps in the existing data necessary to fully apply this methodology across all customer services classes and in all service regions. The most recent REUS data has been used in developing the examples provided; however, this information needs to be supplemented with additional data and research. The Utilities will continue to refine this approach as more information about customer decisions and behaviours, as well as the performance of new technologies and EEC programs becomes available. However, for the foreseeable future, we will continue to prepare a residential customer additions and natural gas demand forecast using the traditional methodology as discussed in Section 4.2.

The Utilities have not yet explored the application of this end-use approach to forecasting of design day demand. In general, we expect to continue adding residential customers as described in Section 4.2.5, and due to the temperature sensitive nature of this demand we expect design day demand to continue growing, causing overall demand on the Terasen Utilities' systems to continue become peakier. Further, we expect the impact of the changing consumption trends among new customers to have minimal impact on overall design day demand over the next few or perhaps the next several years. Over the longer term this impact will grow; therefore, the Utilities intend to analyse the application of this end-use approach on design day demand.

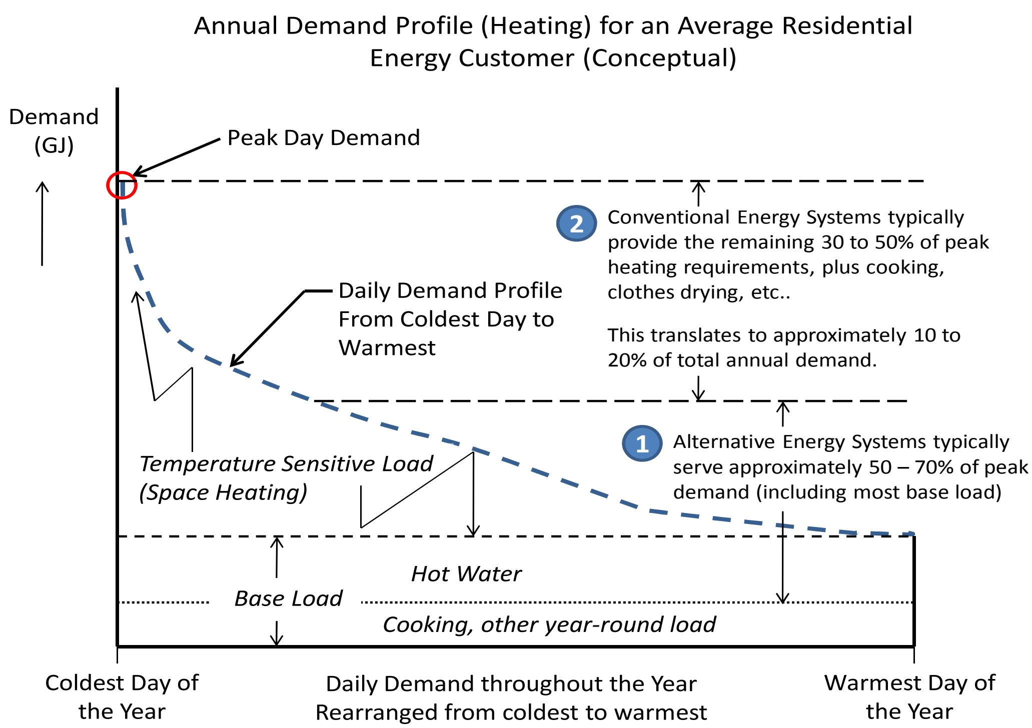
4.3.2 FORECASTING DEMAND FOR RENEWABLE THERMAL ENERGY

Delivering renewable thermal energy solutions is an important part of the Terasen Utilities low carbon energy strategy. While natural gas service will continue to form the Utilities' core business, we are growing our integrated, alternative energy solutions to better meet the needs of customers and communities. As our alternative energy services grow and evolve, the Utilities need to forecast demand for these new products and services in order to better plan for the resources we need in order to deliver them as well as to understand the impacts on our conventional natural gas demand. Forecasting demand for these services also allows us to examine the impact on carbon emissions and how best to meet this new, emerging need among our customers.

Examples of renewable, thermal energy solutions include geo-exchange, waste heat recovery and solar thermal energy systems as discussed in Section 3.1. The Utilities are improving their methodologies for forecasting demand for these solutions and, although it is not yet completely developed, the discussion below provides a conceptual demonstration of our approach. Today, the development of these new products and services remain in early stages and we expect that initial growth will be gradual, but increasing over time, allowing us to more fully develop and validate our methodologies for forecasting demand for these services over time.

Figure 4-17 illustrates how a renewable, thermal alternative energy system can impact a customer's need for conventional energy service. The graph shows thermal energy demand throughout the year for a typical residential/commercial customer[92] rearranged from the coldest day of the year to the warmest. Demand during the warmer days to the right of the graph is referred to as base load because it serves year round needs such as cooking, hot water and perhaps a small amount of space heating. As the temperature decreases (moving left along the graph) energy demand increases primarily for space heating and is highest on the coldest day of the year (peak day).

Figure 4-17: Annual Thermal Demand Profile for a Residential Energy Customer



The costs of designing a renewable thermal energy system to meet demand on every day of the year, including the coldest are extremely prohibitive. Therefore, these systems are typically designed to meet thermal energy demand for about 50 to 70% of design day, including a portion of the base load (No. 1 in Figure 4-17). This type of system can therefore serve approximately 80 to 90% of this customer's annual demand. The remainder of the demand (No. 2 in Figure 4-17) is then supplemented by conventional energy systems, which the Terasen Utilities believe is best met by natural gas where it is available.

District and discrete energy solutions are more complicated than conventional energy systems and can vary in scope and size depending on the type of solution and the individual customer

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[92] For customers whose primary thermal energy need is for space heating.

needs. Very little historical data exists from which to identify potential future trends. For the purposes of explaining the concept in this LTRP, the Terasen Utilities have just considered multifamily residential condominiums and residential customers as examples for explaining the alternative energy forecasting methodology and the results of forecasting exercise example. We have discussed the impact on conventional natural gas demand and measured the impacts of these services on GHG emission reductions. The methodology for estimating demand is based on a per customer basis comparing the baseline and the alternative energy solutions to meet the same end use demand and extrapolating that for the total number of customers. At this point the total number of customers expected for each example is based on the best available information Terasen Utilities has today and is not a formalized forecast itself.

4.3.2.1 Multi-family Condominium and Apartment Buildings

One of the best opportunities to implement renewable thermal energy solutions is during the development and construction of new multi-family residential complexes and multi-unit, mixed use residential and commercial buildings. Replacing conventional energy systems in these buildings with, for example, geo-exchange, waste heat capture and solar-thermal systems in combination with conventional natural gas to meet peak demand requirements, can cost effectively improve energy efficiency and reduce GHG emissions over a greater scale than can be achieved in lower density developments[93]. Thermal energy demand in these applications includes building heating and cooling.

- **The Demand Scenario**

To demonstrate the impact of these types of systems on conventional energy demand and GHG emissions, the Utilities examined a demand scenario in which a representative 100-unit condominium building is used to model demand growth over time. The assumptions used for this analysis are provided in Appendix B-6. In the scenario, a build out of 185 such buildings is modelled over a 10 year period[94]. The energy use and emissions for the application of conventional energy systems (electricity for space heating/cooling and natural gas for water heating and make-up air) is then compared to the application of alternative renewable systems in all of the 185 buildings. The 100 unit residential building is selected as a reasonable size model to represent the market place for multi-unit buildings. The energy inputs and assumptions for the 100 unit model are provided in Appendix B-6. This scenario is set within the Lower Mainland, where a build-out of 185 such buildings over a 10 year period is a reasonable expectation[95]. A survey of builder / developer attitudes toward installing these types of energy systems (Appendix B-7) supports this expectation.

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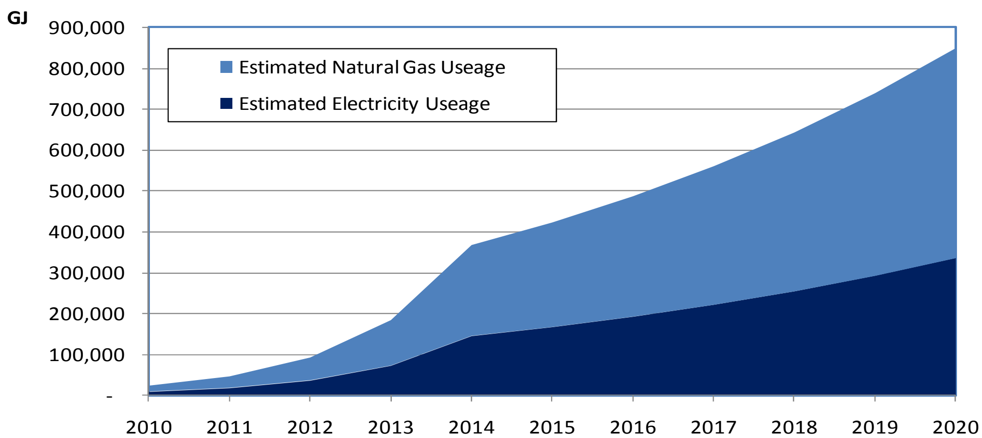
[93] When applied to a single building these integrated energy systems are referred to as discrete energy systems as compared to district energy systems that provide thermal energy to multiple buildings in a community.

[94] Since very little historic information and experience is available to inform our analyses and many uncertainties remain, we have limited our examination to a 10 year period.

[95] Extrapolating from 2008 and 2009 housing starts data, we have estimated that this build-out represents approximately 20% of the total new condominium / apartment building market over the next ten years.

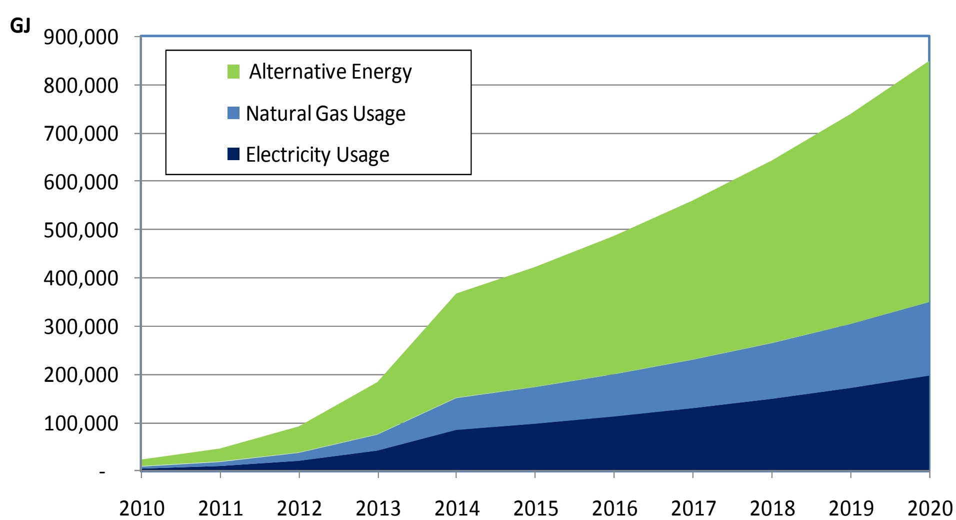
In this scenario, the number of alternative, integrated energy systems implemented in the initial years is small, but the growth rate is initially high, with the number of systems implemented doubling through the first 4 years. Beyond 4 years, growth occurs at a slower pace, resulting in a total of 185 systems at the end of the 10 year period. Figure 4-18 shows the energy delivered to heat and cool these condominium buildings through to the year 2020. The inputs into this demand curve are based on a per-customer or per-unit basis and then extrapolated for the total number of customers.

Figure 4-18: Total Annual Thermal Energy Consumption for 185 Buildings – Conventional Energy Systems



A wide variation of integrated energy systems is possible. The Utilities have modelled this scenario using a typical geo-exchange system that would serve approximately 70% of the buildings thermal energy requirements. Figure 4-19 presents the comparative electricity and natural gas usage if all 185 buildings is constructed using the integrated energy design.

Figure 4-19: Total Annual Thermal Energy Consumption for 185 Buildings - Alternative Systems



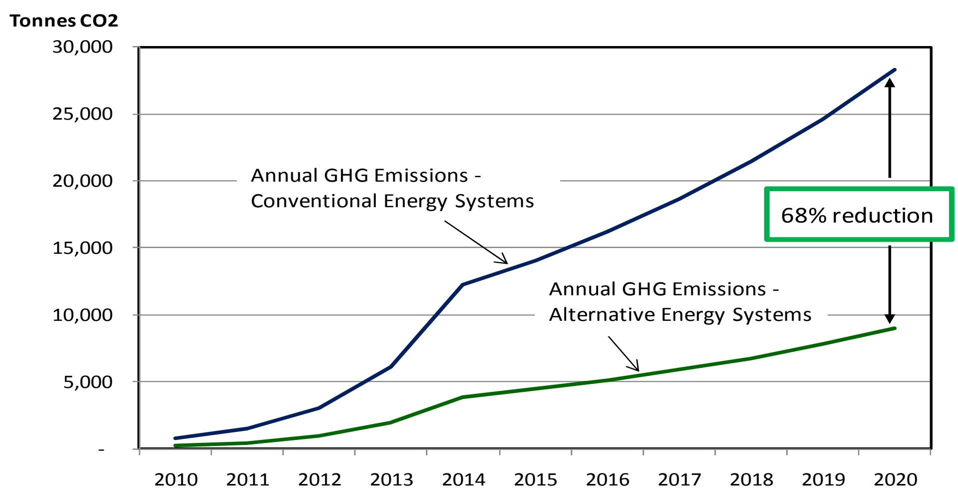
- **Natural Gas and Electricity Savings**

The implementation of renewable thermal energy systems in this scenario results in a total annual energy savings of 362,094 GJ of natural gas and 38 GWh of electricity by the year 2020. The annual natural gas savings in 2020 is approximately equivalent to removing the GHG emissions of 62,800[96] passenger cars. Cumulative natural gas and electricity savings over the ten year period are approximately 1,880,000 GJ and 199 GWh respectively.

- **GHG Savings**

The savings in both natural gas and electricity for this scenario results in the GHG reductions shown in Figure 4-20. Total cumulative GHG[97] savings over the 10 years is approximately 100,304 tonnes of CO_2e by 2020 which represents 68% reduction from the baseline emissions.

Figure 4-20: GHG Emissions Comparison for 185 Buildings – Conventional vs. Alternative energy Systems



4.3.2.2 Residential Single Family Homes and Townhouses

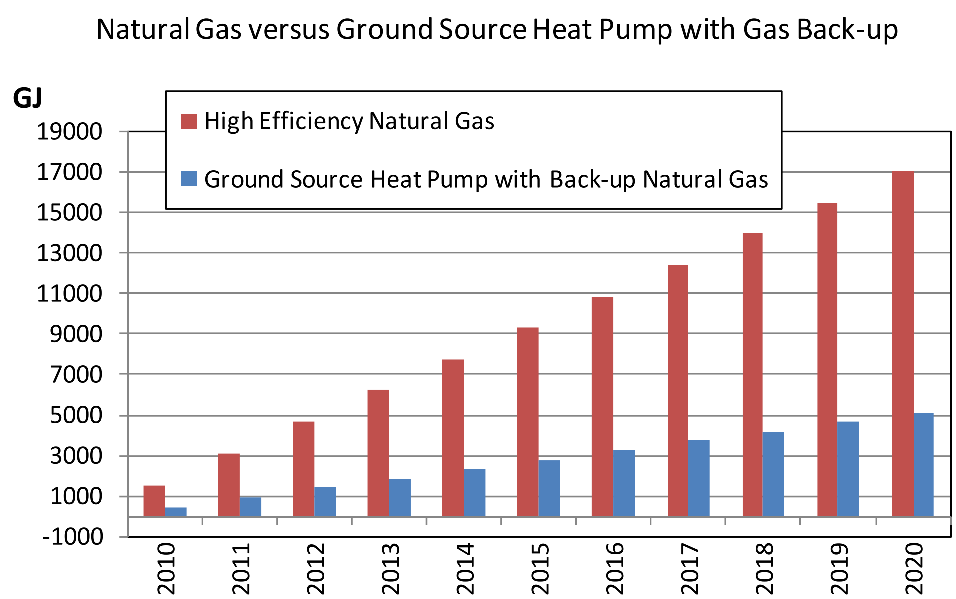
The Terasen Utilities conducted a similar demand scenario for lower density residential developments, again in the Lower Mainland setting. A range of alternative energy solutions exists for the single family home and townhouse type developments, including air source heat pumps, ground source heat pumps (GSHP), solar thermal and high efficiency, on demand type energy systems that use conventional energy sources. These systems can improve energy efficiency and reduce GHG emissions, and may reduce annual energy costs.

96 Number derived using the US Environmental Protection Agency, Greenhouse Gas Equivalency Calculator.
97 Based on a GHG emissions factor of 0.0510 tonnes per GJ for Gas and 0.0061 tonnes per GJ for electricity, from the Greenhouse Gas Emission Assessment Guide for British Columbia Local Governments, February 2008.

Each of these systems, however, presents implementation challenges, such as the high cost of installation and equipment and the increase in peak load for the conventional energy system used as a back-up for the alternative energy during peak demand periods. The demand scenario we have examined compares the application of a ground source heat pump with natural gas back-up to a conventional energy system using 90% or higher efficient heating equipment in new, single family homes. At this time, the comparison is limited to space heating demand. The ground source heat pump system is assumed to meet approximately 70% of the dwellings' annual space heating energy requirements.

Due to the high equipment and installation costs for ground source heat pumps, the Terasen Utilities believe implementation of this energy choice will be quite limited in spite of the energy savings and GHG reduction benefits. We estimate that the current level of energy efficiency and conservation program funding (discussed in Section 5) that is available as part of the Innovative Technologies portfolio, could support the implementation of this technology in about 33 homes per year. For this scenario, we have assumed this level of funding is available and therefore this level of implementation occurs for the next 10 years. A comparison of natural gas consumption is presented in Figure 4-21. The total number of systems implemented reaches 694 and the resulting cumulative natural gas and GHG savings are 71,600 GJ's and 3,651 tonnes of CO_2e, respectively.

Figure 4-21: Annual Space Heating Energy Comparison - Single Family Dwellings



4.3.2.3 District Energy Systems

Development of district energy systems (also called community energy systems) that combine renewable thermal energy technology with conventional, supplementary energy to serve the thermal energy needs of an entire community is an important priority initiative for the Terasen Utilities. Energy comparisons for district energy systems can be conducted using similar methods to those described above for condominium / apartment buildings and single family dwellings. Each district energy system, however, is very unique in the technology and source energy combinations employed and the wide ranging end-uses served within each community. The Utilities are continuing to examine the potential comparisons that might be made for alternative, renewable energy systems versus conventional energy technology within district energy systems in order to improve demand forecasting and scenario analysis for these types of systems. Although final results of such comparisons are not yet available for more detailed discussions, general conclusions on energy savings and GHG reductions can be made by increasing the scale of the results from the condominium / apartment and single family dwelling scenarios to that of a complete community.

4.3.2.4 Commercial and Industrial Renewable Thermal Energy

Modelling the potential demand for commercial and industrial thermal end uses is also a very complex exercise. A broad variation of commercial and industrial end uses for thermal energy exist, from basic space and water heating needs to high temperature and pressure cleaning applications to balancing thermal energy needs of sports complexes. For many of these applications, forecasting future demand is subject to market cycles and trends that are different from those impacting housing markets. Many industrial processes require higher and more consistent temperatures than can currently be achieved by the types of renewable thermal energy initiatives the Utilities are advancing.

In some cases; however, the Utilities will be delivering renewable thermal demand for commercial applications as part of their energy services to mixed use buildings and communities. As such, we will continue to explore the application of forecasting methodologies for renewable thermal, alternative energy solutions to these customer groups, including conducting additional market research on commercial and industrial needs and intentions for thermal energy.

4.3.2.5 Conclusions and Implications for Thermal Energy Demand Forecasting

The methodologies, scenarios and examples described above for forecasting thermal energy supply and resource needs are still in development. While initially, the scale of development of these alternative energy systems will be slow compared to the Utilities core natural gas business, we expect the focus on developing these services today will result in growing market penetration in future years. Therefore, the impact of implementing these solutions on natural gas demand the Utilities existing customers will be limited in the initial years. The Utilities need to be applying resources to the forecasting of demand scenarios for these services in order to better understand their impact over time on our natural gas infrastructure, annual and design day demand, system capacity needs and rate design issues. As such, we need to be acquiring additional tools, data, research and resources today that are needed to fully develop and implement these forecasting approaches. The Utilities will also continue to apply the proven and accepted traditional natural gas forecasting methodologies discussed in Section 4.2 for the foreseeable future.

The examples and observations in new methodologies developed for this LTRP are so far limited to achieving energy savings and emission reductions, and developing resources to meet the energy needs of our customers and the targets set out in government policy. The analyses become much more complex when including costs and rate impacts over time. These additional studies are, however, vital in understanding the implications of policies that government at all levels implement and the initiatives that utilities pursue. To this end, the Terasen Utilities intend to continue working with other B.C. utilities with the objective of developing a complete, base-line forecast for thermal energy demand in the province against which alternative future scenarios and energy mixes can be compared. The Utilities are also continuing to model[98] a range of energy comparisons across housing types and throughout their service regions to understand the implications of various energy initiatives that are or may be undertaken in the province such as adopting EnerGuide for Houses 80[99] as a building code compliance requirement. The results of these comparisons will be discussed in future submissions to the Commission by the Utilities.

4.3.3 DEMAND SCENARIOS FOR NATURAL GAS AS A TRANSPORTATION FUEL

In addition to the carbon reduction and air emission benefits of using natural gas as a transportation fuel, demand growth from increased adoption of NGV solutions in B.C. will help to optimize the use of the Utilities existing infrastructure, to the benefit of all of the Terasen Utilities' customers. The Utilities expect the future development of B.C.'s NGV market to be quite different than past experience (described in Section 2). Low carbon transportation fuel requirements have been legislated, the fuel price advantage for natural gas over conventional diesel and gasoline has improved further, all levels of government are increasing their focus on reducing transportation related emissions, and proven technology ready for commercial use is readily available. This changing planning environment has resulted in the development of new NGV initiatives for the Terasen Utilities and hence the examination of future NGV related demand growth scenarios outside of our traditional natural gas demand forecast.

Today, the total number of NGVs fuelled by the Terasen Utilities is approximately:

- 550 light duty vehicles; consisting of 500 passenger cars and trucks and 50 light duty Terasen Utilities fleet vehicles[100];
- 30 medium duty delivery vans; and

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[98] HOT 2XP and HOT 2000 are energy modelling software available from NRCan that the Terasen Utilities are using to model a range of energy comparisons in each of their service regions.
[99] NRCan energy rating system for homes: http://oee.nrcan.gc.ca/energuide/home.cfm
[100] Terasen fleet vehicles are scheduled for regular operations in the fall of 2010.

- 50 urban transit buses.

Looking ahead, the target market for the Utilities' NGV initiatives has changed, with return-to-base fleet operations being the most promising near-term adopters and availability of LNG as a transportation fuel increasing the number of potential NGV applications. Original equipment manufacturers have responded to the needs of this market segment and the changes in the marketplace by making a wider range of NGV equipment available in North America. This section describes the Utilities examination of potential future NGV related natural gas demand, beyond the expectations included in our current, conventional demand forecast.

Although prevailing government policy and objectives, and social attitudes have created an environment of acceptance and need for more NGV development, there are remaining challenges to more widespread implementation, such as the lack of a complete service offering including fueling infrastructure and the incremental cost of natural gas fuelled equipment over conventional diesel and gasoline equipment. Further details about the Utilities' new NGV initiatives and why we are well positioned to overcome these challenges are contained in Section 3.

The use of incentive funding through Energy Efficiency and Conservation - Innovative Technology programming (discussed in Section 5) is part of the solution to encourage increased adoption of NGV solutions. The Utilities have developed three demand scenarios for natural gas specifically as a transportation fuel by using the incentive funding as an initial market driver to increase awareness and adoption in the short term. Over the longer term, these scenarios also rely on a market transformation to wider adoption, catalyzed by the Utilities' Innovative Technology incentives and NGV initiatives.

Although new growth in NGV related demand for natural gas is expected, a number of challenges exist in developing a demand forecast. For example, historic sales of NGV medium and heavy-duty trucks sold in B.C. are negligible, providing little market data to inform future demand forecasts. The Utilities have therefore used a number of other information sources and techniques to develop a range of three alternative future demand scenarios. These scenarios are largely developed by incorporating historical NGV transportation load, potential future incentive funding as well as external factors such as market acceptance, OEM availability, government policy, government incentives, and macro-economic conditions. The scenarios allow a discussion of the benefits and implications for increasing throughput on the Utilities' natural gas system and reductions in GHG and other transportation related emissions.

The Utilities will continue to develop their methodologies for forecasting demand for these solutions. As demonstration projects and first adopters in the province show success and the remaining challenges to implementing complete solutions are solved, we expect that NGV solutions will be adopted at a faster pace as businesses seek out their environmental benefits and operational cost advantages. As that occurs, the Utilities will validate and refine the underlying assumptions on fuel consumption and market uptake, and incorporate load growth expectations from this market into its natural gas demand forecast.

4.3.3.1 Target Market segments

B.C.'s total transportation energy use in 2007 was 370 PJ from all fuel types[101]. The long term target market for the Terasen Utilities, which includes light and medium-duty trucks, heavy duty trucks, buses and marine applications, represents the majority of this demand at 292 PJ of total energy use[102]. Table 4-4 shows 2007 fuel consumption for the various transportation sectors in B.C. Capturing even a small portion of this overall market can result in a significant increase in natural gas throughput for the utilities, which benefits existing customers and can achieve large emission reductions for new customers.

Table 4-4: 2007 Transportation Fuel Consumption by Category in B.C.

Category	Fuel Type (PJ)				
	Gasoline	Diesel	Heavy Fuel Oil	Other	Total
Passenger Cars	64.1	0.6	-	1.4	66.1
Light Duty Trucks	75.8	0.3	-	2.3	78.4
Medium Duty Trucks	7.2	13.7	-	-	20.9
Heavy Duty/Vocational Trucks	-	66.0	-	-	66.0
Buses	0.2	5.3	-	0.6	6.1
Marine	-	12.2	42.1	-	54.3
Total:	147.3	98.1	42.1	4.3	291.8

Source: NRCan, 2007

Notes:

- Does not include school buses.
- Heavy duty trucks and vocational trucks are combined as both consume 100% diesel.
- Other includes propane, natural gas, and electricity

4.3.3.2 Per Vehicle Use Assumptions for NGV Demand Scenarios

The Terasen Utilities used market information acquired from pilot projects, project engineering work, industry partners, and suppliers to develop reasonable estimates on vehicle consumption for each vehicle segment in the target market. We believe industry data is more representative of the target market that is being pursued. Under all three scenarios, the NGV consumption in GJ is determined by applying a conversion factor – referred to as Diesel Litre Equivalents103 ("DLE") – to the fuel consumption data for conventional fuel vehicles. This conversion creates a comparable assessment of the energy use from diesel versus natural gas. These values are held constant for each of the scenarios. Table 4-5 shows the natural gas consumption as well as the average distance travelled for vehicles in each of the categories. Appendix B-8 describes the basis on which these vehicle consumption estimates are made.

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101 From NRCAN 2007

102 Target market does not include motorcycles, passenger air, freight air, passenger rail, freight rail, off-road vehicles, and school buses. These sectors represent approximately 78 PJ.

103 The conversion is based on energy content values published in the NRCan GHGenius model. (Diesel at 38.653 MJ/litre – yields conversion factor of 25.9).

Table 4-5: Natural Gas Consumption and Average Distance Travelled for B.C. Vehicle Categories

Category	Scenario Assumptions	
	Annual Consumption per Unit (GJ)	Total Annual # of Kms
Passenger Cars	100	17,500
Light Duty Trucks	170	20,000
Medium Duty Trucks	450	20,000
Heavy Vocational Trucks	800	40,000
Heavy Duty Trucks	2,500	300,000
Buses*	1,840	70,000
Marine	92,000	65,000

* Does not include school buses

4.3.3.3 NGV Demand Scenarios

While many NGV demand scenarios are possible, the Terasen Utilities have identified a combination of factors that we believe provide a reasonable range of future demand for transportation fuel solutions. The "Favourable NGV Environment" scenario provides a most likely case compared to the others, reflecting current conditions based on the best available industry information combined with current energy and emission policies. The "Plus Passenger Vehicles" scenario examines the potential additional demand above the Favourable Environment scenario if a renewed commitment by the government and/or transportation industry toward passenger vehicle NGV solutions is made. The "Low NGV Demand Growth" scenario models a minimum likely amount of NGV demand growth, based on the momentum of recent carbon legislation and the efforts of businesses to competitively differentiate based on environmental stewardship practices.

➢ **Favourable NGV Environment Scenario**

The Utilities believe that the Favourable Scenario is the most likely of the three NGV demand scenarios developed, as it is based on the current positive external opportunity for increased adoption of NGV solutions as described in the introduction. This scenario is based on the best possible information available today on expected vehicle growth in the defined target segments, continued incentive funding expectations, favourable natural gas prices and availability of fueling infrastructure. The assumptions underlying this scenario are:

- Adoption of NGV solutions over the long term across all the identified target market segments except passenger cars;
- Incentive funding will continue to be a driver to reduce the initial incremental capital cost across the entire target market segments excluding passenger cars;

- In the later years, there is widespread adoption and uptake of NG vehicles from the success of the initial pilot projects;
- Public policy will continue to support the use of NG as a transportation fuel to meet climate action legislative targets;
- NG commodity prices will continue to remain favourable against other fuel types as more shale gas comes online;
- Economies of scale will help push the initial capital costs for natural gas fuelled equipment down over the longer term;
- Availability of targeted fueling infrastructure supporting the expected demand and uptake;
- Availability of OEM vehicles and improvements in conversion technology across light duty and medium duty vehicles where it is not prevalent today.

In this scenario, the Terasen Utilities forecast net cumulative transportation growth of 34,540 vehicles by 2030 which results in approximately 30 PJ. Table 4-6 shows the expected rate of adoption over the 20 year planning horizon. The total number of vehicles each year is multiplied by the per vehicle consumption across each vehicle category to estimate the total annual NGV demand.

Table 4-6: Total Number of Expected Vehicles by Category – Favourable NGV Environment Scenario

Category	Total Number of Vehicles – Favourable NGV Environment					
	2010	2011	2015	2020	2025	2030
Light Duty Trucks	550	550	1,000	5,000	10,000	20,000
Medium Duty Trucks	30	30	100	500	1,500	2,000
Heavy Vocational Trucks	-	25	200	1,000	3,000	5,000
Heavy Duty Trucks	-	9	200	1,000	3,000	6,000
Buses	50	75	250	750	1,000	1,500
Marine	-	-	1	5	20	40
Total:	630	689	1,751	8,255	18,520	34,540

Note: Passenger Car segment is not pursued by Terasen Utilities in Favourable NGV Environment Scenario

The Terasen Utilities believe that this is a reasonable estimate of future market penetration for our NGV initiatives, given the current and emerging low carbon fuel policy environment and emerging business drivers for adopting NGV solutions.

- **Plus Passenger Vehicles Scenario**

The Plus Passenger Vehicles scenario illustrates the magnitude of additional consumption that could occur above the level set by the Favourable NGV Environment Scenario if the momentum of new NGV initiatives causes renewed interest and development of NGV solutions in the passenger vehicle market category. Although there are numerous factors that can affect consumption levels, the following items occurring concurrently are viewed as the main additional drivers in this scenario:

- Increased incentive funding available from Government and from EEC programs to encourage widespread adoption of NG across all market segments including passenger cars;
- The natural gas price advantage continues to widen with respect to other fuel types;
- Public policies are formed to encourage use of NG across certain segments like heavy duty and medium duty trucks to aggressively reduce GHG's;
- Tax breaks are provided to further encourage customers to adopt NG and other low carbon vehicles;
- A renewed commitment by the government and / or fuel retailers to make fueling infrastructure for passenger vehicles publicly available; and
- Auto makers re-enter the OEM market with natural gas passenger vehicle products at competitive prices.

The Terasen Utilities forecast net cumulative transportation growth of 94,500 vehicles and total energy use of approximately 36 PJ by 2030 under the Plus Passenger Vehicles Scenario. While reachable, this scenario envisions additional government and transportation industry intervention to advance the adoption of NGV solutions in the B.C. passenger vehicle market to capture almost 6% of that market by 2030. This additional market capture is not anticipated in the near future and is not part of the Utilities new NGV initiatives, and is therefore considered less likely to occur than the Favourable NGV Environment Scenario.

- **Low NGV Demand Growth Scenario**

Given the current provincial policy environment, existing incentive funding for implementing NGV solutions, and growing industry interest in employing these incentives, the Utilities believe that at minimum, a modest level of NGV growth will occur even in a less favourable environment than outlined in the previous scenario. The Low NGV Demand Growth scenario depicts the lower bound of future consumption that could reasonably occur. The drivers that would cause this lower level of future demand for natural gas as a transportation fuel are:

- Incentive funding leads to market growth and vehicle additions but fails to stimulate wider adoption beyond the funded projects;
- Natural gas prices remain favourable versus conventional fuels but are insufficient to drive higher levels of growth;
- Public policy measures to encourage the use of NG as a transportation fuel are less aggressively pursued;
- Limited new OEM models are made available for this market in B.C., particularly in the light duty truck category.

The Terasen Utilities forecast net cumulative transportation growth of 16,280 vehicles and total energy use of approximately 13 PJ by 2030 under the Low NGV Demand Growth scenario. Due to the high level of public and government focus on reducing emissions from the transportation sector, we believe this scenario is less likely to occur than the Favourable NGV environment scenario.

4.3.3.4 Scenario Implications

Figure 4-22 shows the load growth and total number of NGVs expected in each of the three NGV demand scenarios. The Utilities have estimated[104] that in the Favourable NGV Environment Scenario, 30 PJ of natural gas demand for transportation represents about 6.5% of the total target transportation market in 2030 (Figure 4-23). Capturing 6.5% of the transportation fuel market over the next 20 years is a reasonable expectation for this low carbon alternative to conventional fuel.

[104] Estimation based on the assumption that the current target market size grows at approximately 2% per year, equal to rate of GDP growth, based on current 5 year B.C. Ministry of Finance GDP forecast.

Figure 4-22: Comparative NGV Demand Scenarios

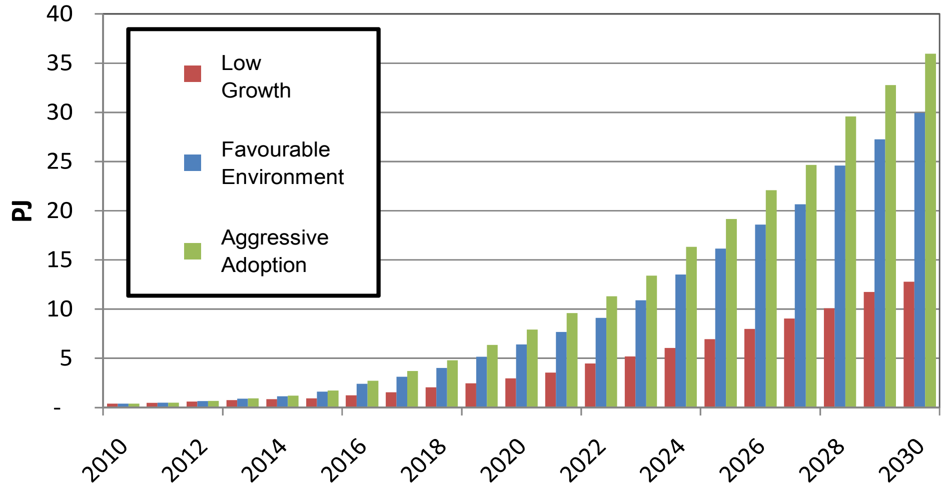
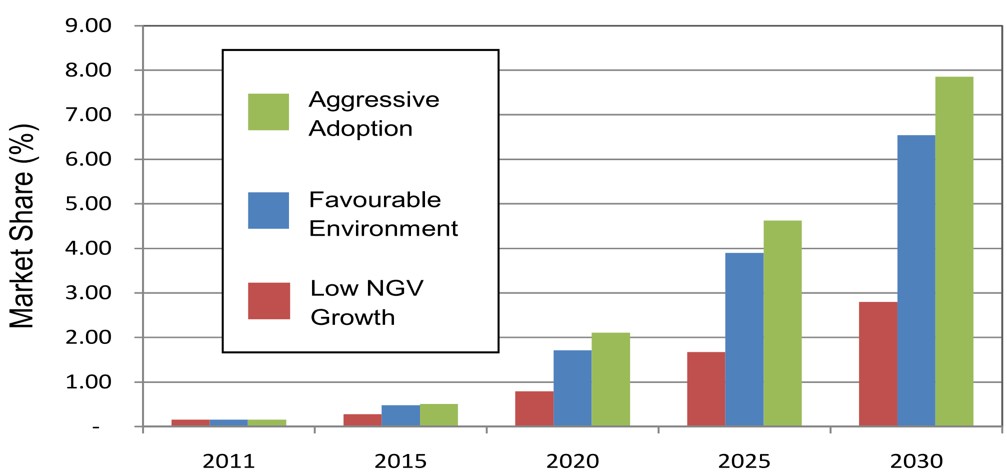


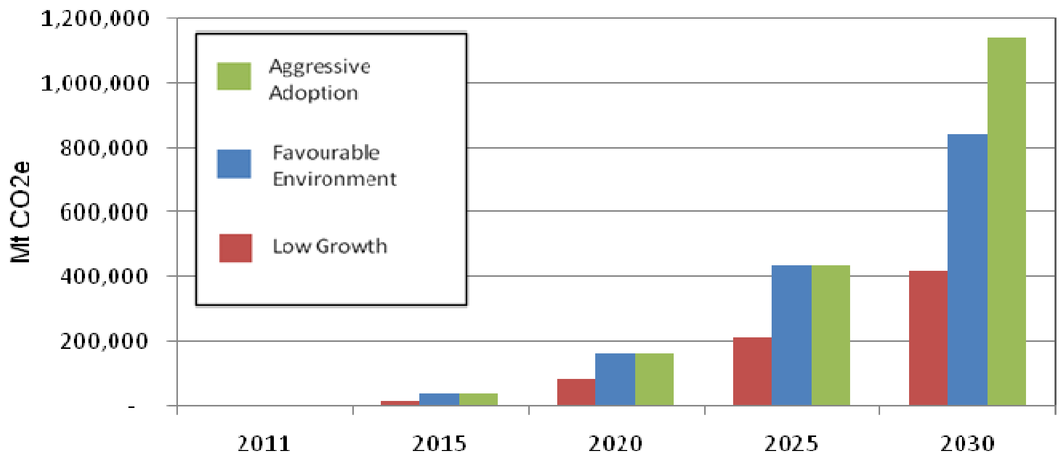
Figure 4-23: Demand Scenario NGV Share of Transportation Market



Approximately 15% of diesel demand can be replaced by natural gas in this scenario, contributing approximately 77% of the total 844,000[105] tonnes of CO_2e emissions. The amount of GHGs reduced in the Favourable Environment demand scenario is the same amount created by burning approximately 360 million litres of gasoline. Figure 4-24 shows the total cumulative GHG savings for each of the three demand scenarios at 5 year increments over the planning horizon. The Low NGV Demand scenario results in half the GHG reductions possible in the Favourable NGV Environment Scenario and falls well short of helping to meet provincial goals for carbon reduction.

[105] Based on emissions factors of 1,433 grams per kilometre for diesel, 1,149.7 g/km for CNG and 1,035.1 g/km for LNG, published in GHGenius 3.17 software available from NRCan.

Figure 4-24: Three Scenarios - Total Cumulative GHG Reductions (Mt CO2e)



4.3.3.5 Transportation Demand Scenario Conclusions

The changing nature of market conditions for NGV solutions in B.C. has opened up an important new target customer segment for the Terasen Utilities. The Utilities believe that demand growth of 30 PJ over the next 20 years, representing just 6.5% of the overall market for transportation fuels, is a reasonable expectation for natural gas load from its new NGV initiatives. This expectation arises from the favourable market and policy environment that continues to evolve in B.C. together with the new NGV solutions that the Utilities are developing to meet the needs of the commercial, return-to-base, fleet vehicle market segment.

The addition of 30 PJ of throughput on the Utilities natural gas transmission and distribution systems will be an important offset to the levelling off of demand growth from residential and commercial customer segments as improvements in energy efficiency and adoption of alternative, renewable thermal energy solutions begins to make a marked impact in future years. This additional throughput will help to optimize use of the existing natural gas infrastructure to the benefit of all of the Utilities' customers.

4.3.4 CONCLUSIONS FOR NEW FORECASTING ACTIVITIES

The Terasen Utilities' forecasting activities are evolving to capture the changes that are underway in our customers' energy demand patterns as a result of external forces such as changing energy policy and buildings codes and standards, as well as our own initiatives to better serve the needs of our customers. While these changes will not have a marked impact in the short term on natural gas demand, we need to be developing new methodologies in forecasting now to better understand the implications over the long run. The Utilities intend engage their stakeholders in the ongoing development of these new forecasting activities, and will continue to improve our methodologies as we gain further market experience and as new information becomes available.

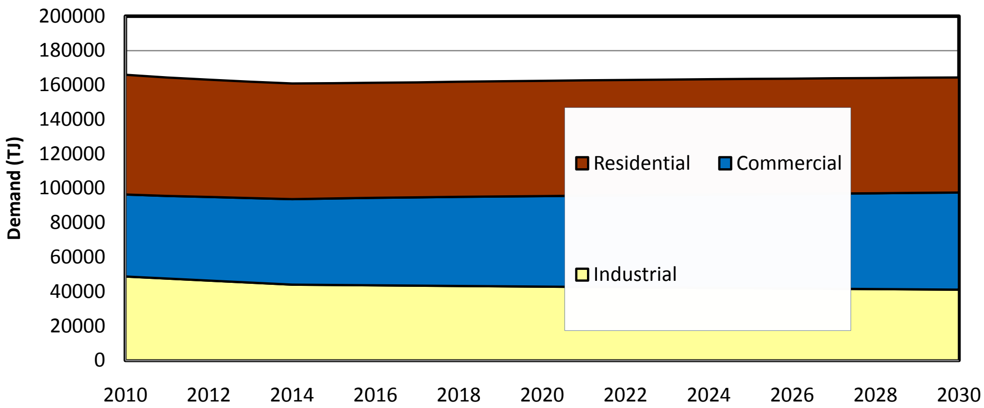
New, alternative energy initiatives by the Terasen Utilities, increased and ongoing EEC activities and implementation of new building codes and standards have the potential to impact growth in annual and design day demand. While the utilities expect to continue adding new natural gas customers as these changes occur, the nature of the demand may well become peakier as natural gas back stops the peaking needs of integrated, renewable thermal energy solutions (Figure 4-17 during extreme cold weather. This shift could in turn affect the natural gas system design and gas supply planning requirements as the demand characteristics of a growing proportion of new customers differs from that of existing customers.

The extent of these impacts and rate of change in demand characteristics is difficult to determine at this early stage of these new energy initiatives. The new methodologies discussed in this section, once fully developed and validated, will help the Utilities better understand the potential implications for long term resource planning and rate design.

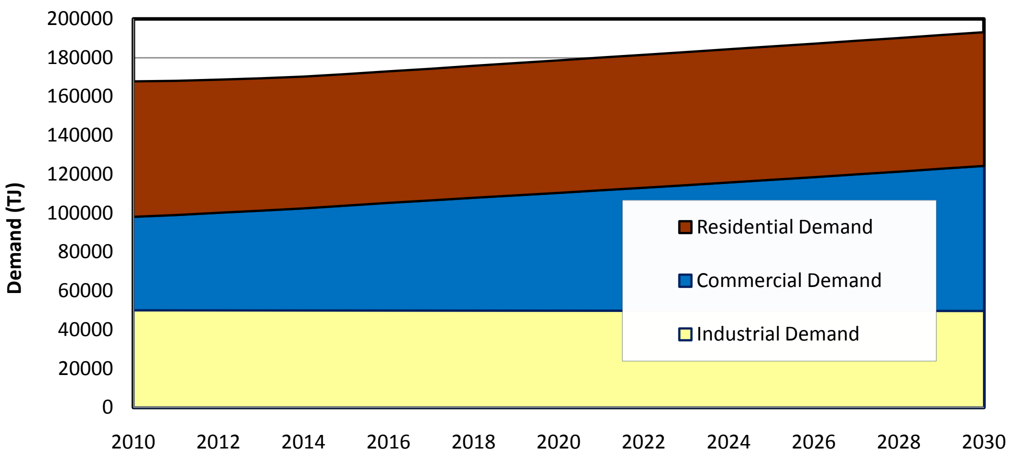
The Utilities will also continue to develop methodologies to forecast energy demand as part of their integrated, alternative energy services and new natural gas vehicle initiatives, in order to plan for the natural gas and alternative energy resources needed to deliver these solutions. Implementation of alternative energy solutions for residential and commercial buildings and entire communities has the potential to significantly reduce conventional energy demand and carbon emissions over time. Increased adoption of new natural gas vehicle solutions can significantly reduce GHG emissions while building efficient, year-round load, countering the declines on system throughput caused be declining residential use rates. The growth in natural gas demand for transportation of 30 PJ forecasted for these new NGV initiatives by year 2030, will be important for adding baseload to the natural gas system and optimizing its use for the benefit of all the Utilities' customers.

A substantial effort will be required in the coming months to undertake these new forecasting activities, fully develop and validate the new methodologies and use them to assess the changes ahead. The tools, data, research and resources needed for these activities will also help to analyze the potential impact of future policy decisions and energy initiatives by governments, energy customers and utilities. To these end, the Terasen Utilities will continue working with other utilities and governments to understand the complete nature of thermal energy demand within the province. All of this new work will need to be done alongside our ongoing traditional forecasting processes as these will remain the primary input into our natural gas system and supply planning activities for the foreseeable future.

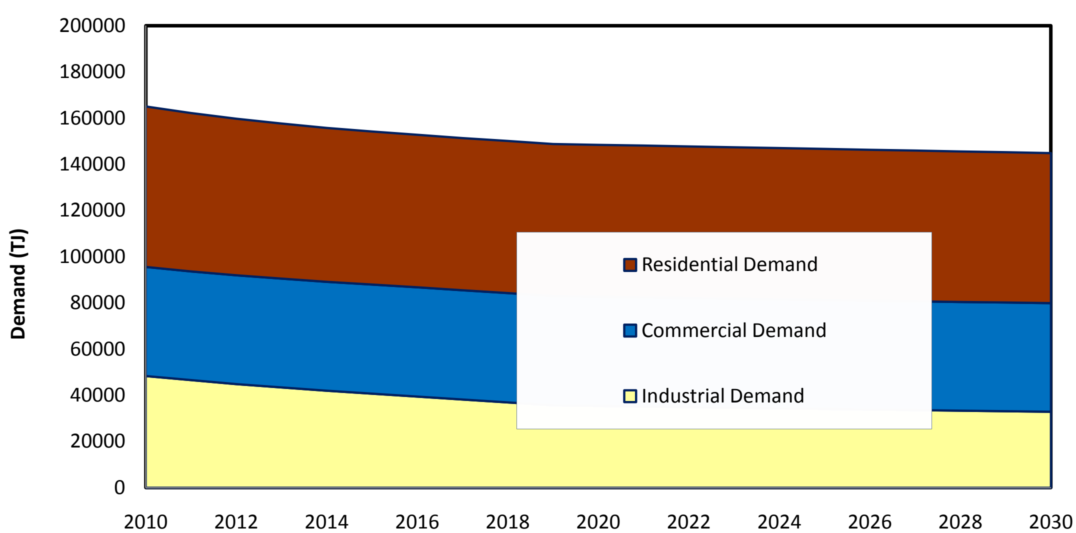
Reference Case: TGI Annual Demand 2010 - 2030

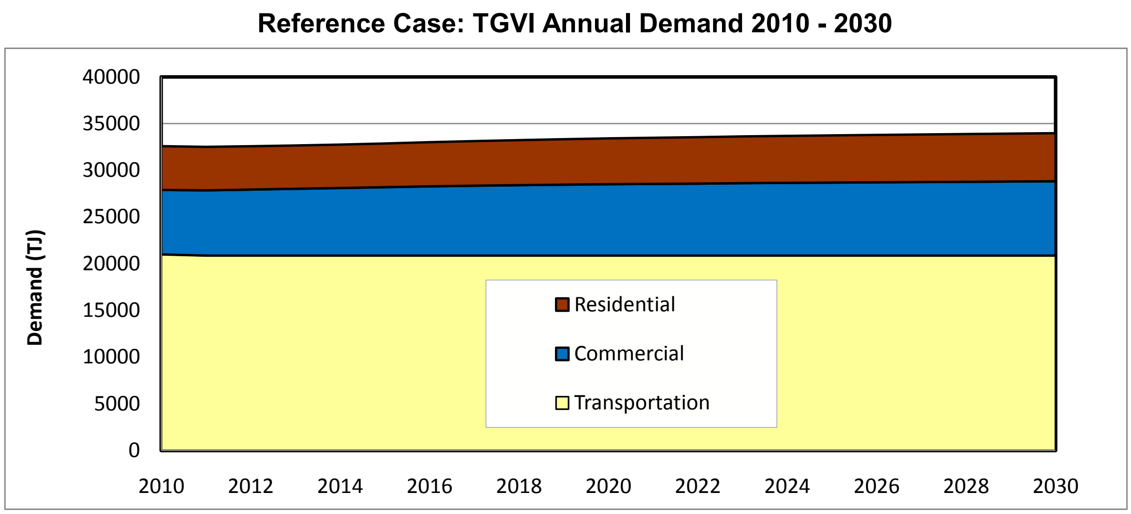


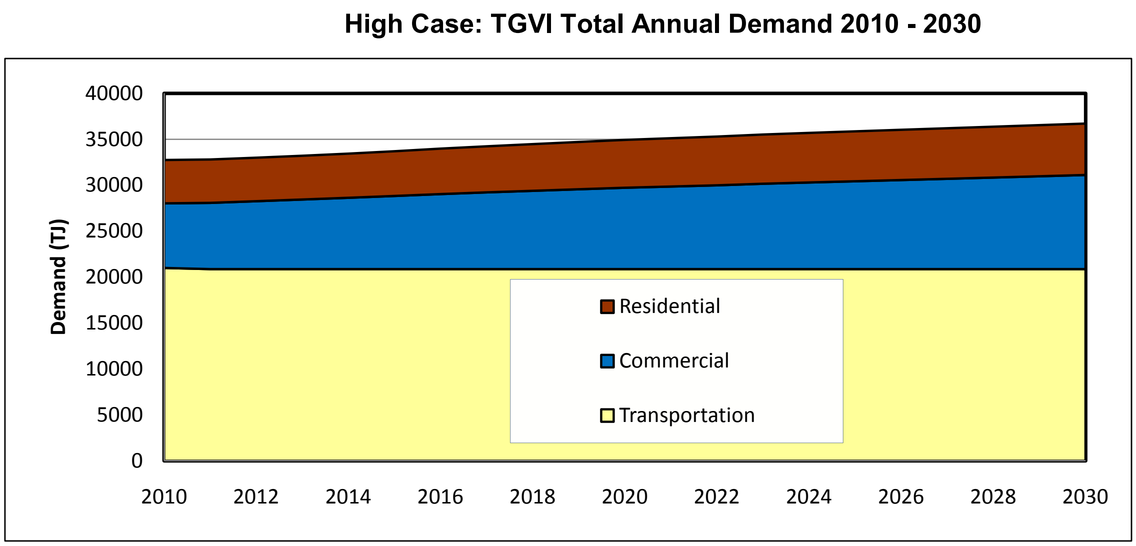
High Case: TGI Annual Demand 2010 - 2030

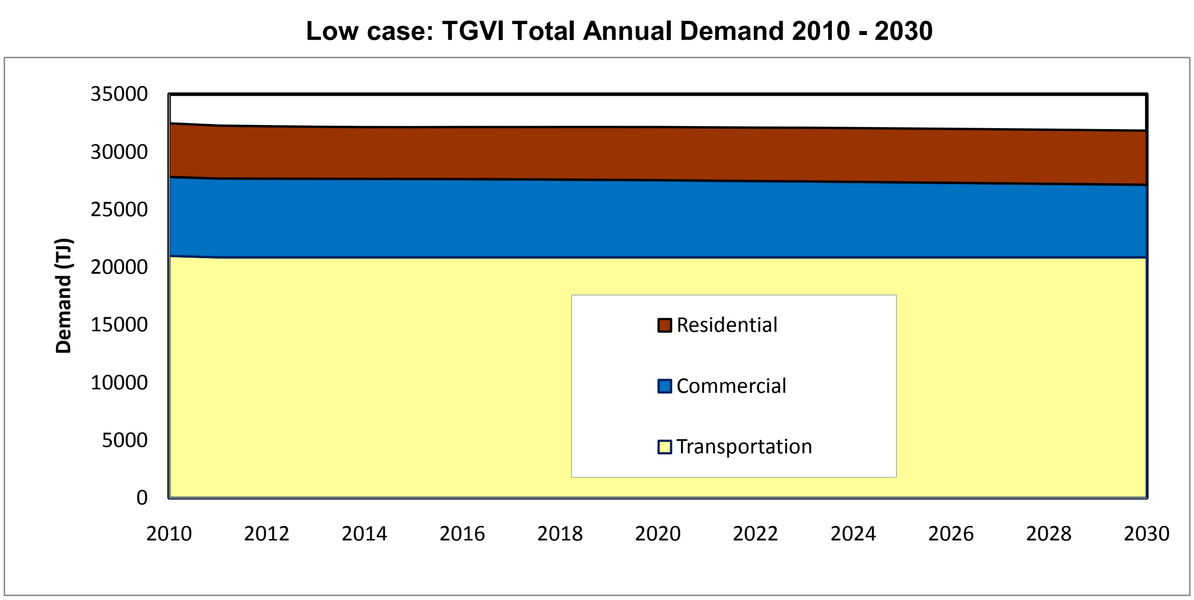


Low Case: TGI Annual Demand 2010 - 2030




Reference Case: TGVI Annual Demand 2010 - 2030
Demand (TJ)
40000
35000
30000
25000
20000
15000
10000
5000
0
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Residential
Commercial
Transportation


High Case: TGVI Total Annual Demand 2010 - 2030
Demand (TJ)
40000
35000
30000
25000
20000
15000
10000
5000
0
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Residential
Commercial
Transportation


Low case: TGVI Total Annual Demand 2010 - 2030
Demand (TJ)
35000
30000
25000
20000
15000
10000
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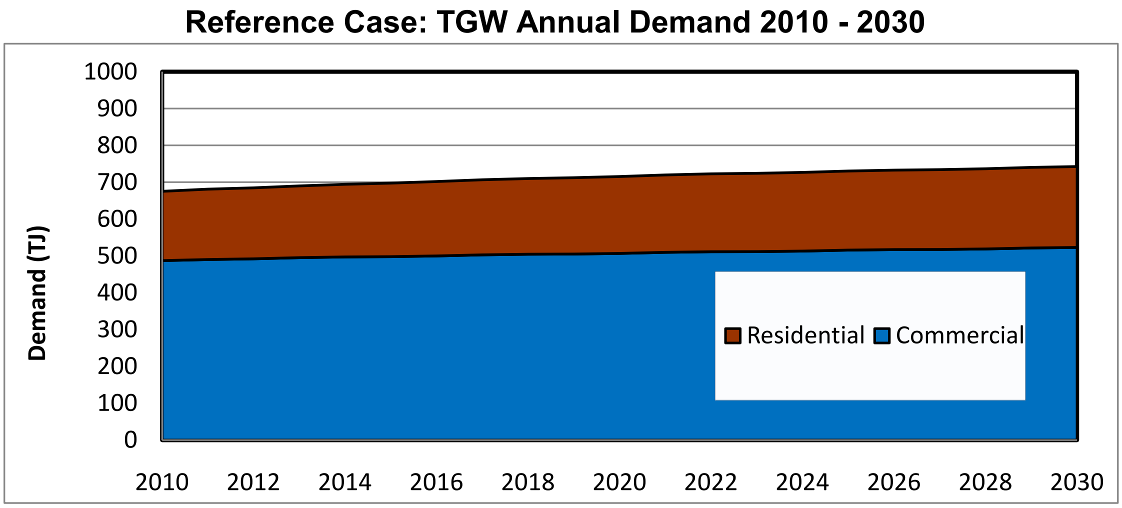
2014
2016
2018
2020
2022
2024
2026
2028
2030
Residential
Commercial
Transportation


Reference Case: TGW Annual Demand 2010 - 2030
Demand (TJ)
1000
900
800
700
600
500
400
300
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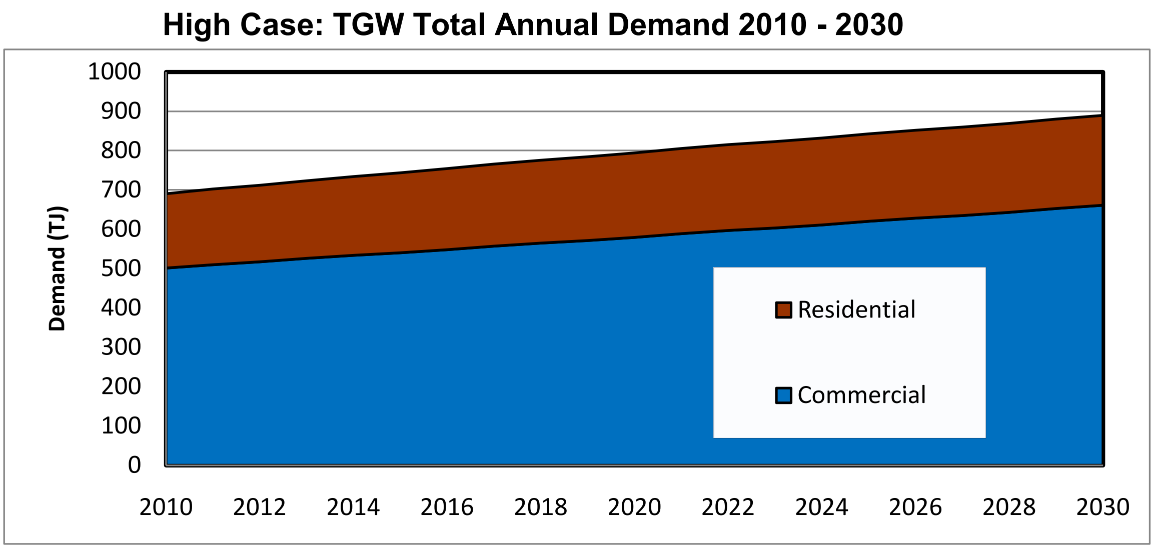
2022
2024
2026
2028
2030
Residential
Commercial


High Case: TGW Total Annual Demand 2010 - 2030
Demand (TJ)
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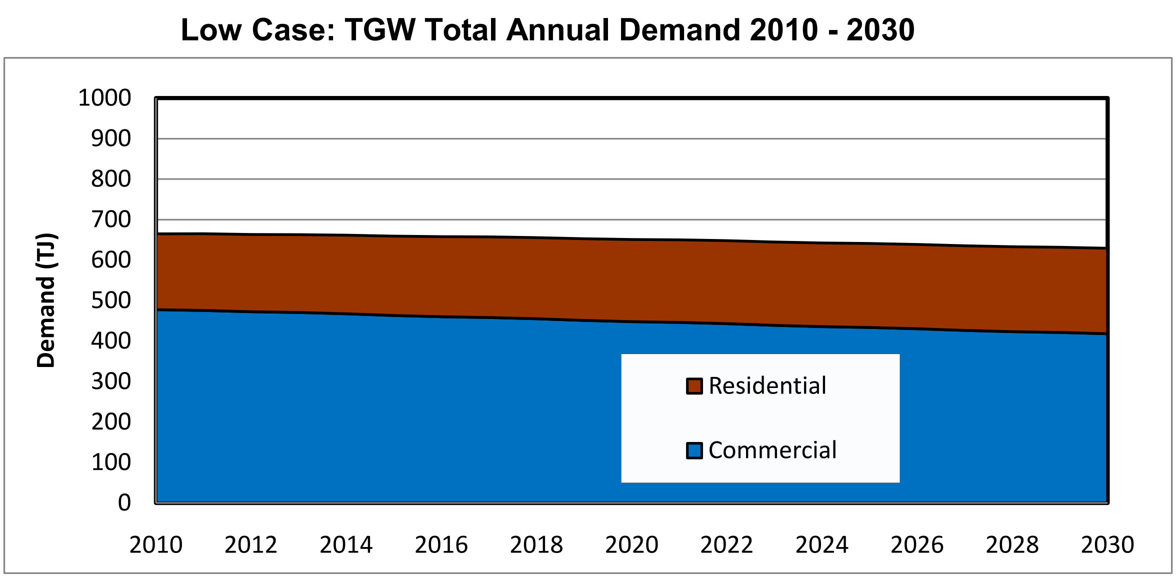
Residential
Commercial


Low Case: TGW Total Annual Demand 2010 - 2030
Demand (TJ)
1000
900
800
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300
200
100
0
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Residential
Commercial

Attachment 167.1

	AGL Resources	Alliant Energy	Atmos Energy	Consolidated Edison	Integrys Energy Group	Northwest Natural Gas	Piedmont Natural Gas	Southern Company	Vectren Corp.	WGL Holdings	Wisconsin Energy	Xcel Energy
Bad Debt	X		X	X	X		X		X		X	
Conservation		X			X		X		X	X		X
CWIP in Rate Base		X	X	X	X		X	X		X	X	X
Decoupling	X	X		X	X	X	X		X	X		
Electric Transmission Costs		X									X	X
Environmental Remediation	X	X	X	X	X	X	X	X	X		X	X
Fixed Cost Recovery Rate Design	X		X					X	X	X		
Generating Plant Outage Costs								X				X
Infrastructure Cost Recovery/ Pipeline Integrity Expense	X	X	X		X	X	X	X	X	X		X
Lost and Unaccounted for Gas	X	X	X	X	X	X	X	X	X	X	X	X
Gas/Fuel Cost Recovery	X	X	X	X	X	X	X	X	X	X	X	X
OPEB	X	X	X	X	X	X	X	X	X	X	X	X
Pension	X	X	X	X	X	X	X	X	X	X	X	X
Rate Stabilization Mechanism							X	X				
Removal Costs	X	X	X	X	X	X	X	X	X	X	X	X
Storm Damage				X	X	X		X				
Weather Normalization	X		X	X		X	X		X	X		

Attachment 197.1

Company	Deferral Accounts
FEI	Revenue Stabilization Adjustment Mechanism (RSAM)
	Commodity Cost Reconciliation Account (CCRA)
	Midstream Cost Reconcilation Account (MCRA)
	Revelstoke Propane Cost Deferral Account
	Interest on CCRA/MCRA/RSAM and Gas in Storage
	SCP Mitigation Revenues Variance Account
	Management
	NGV Conversion Grants
	Property Tax Deferral
	Interest Variance
	Insurance Variance
	Pension & OPEB Variance
	BCUC Levies Variance
	OSC Certification Compliance
	Tax Variance Account
	Accounting Change Related Deferrals
	Customer Service Variance Account
	Depreciation Variance
	Application Costs
	Deferred Removal Costs
	Gains and Losses on Asset Disposition
	2010-2011 Customer Service O&M and COS
	Negative Salvage Provision/Cost
	Gas Assets Record Project
	BC OneCall Project
Enbridge Gas Distribution	DSM Variance Account
	Class Action Suit Deferral Account
	Deferred Rebate Account
	Gas Distribution Access Rule Costs Deferral Account
	Ontario Hearing Costs Variance Account
	Manufactured Gas Plant Deferral Account
	Unbundled Rate Implementation Cost Deferral Account
	Open Bill Service Deferral Account
	Open Bill Access Variance Account
	Municipal Permit Fees Deferral Account
	Average Use True-Up Variance Account
	Tax Rate and Rule Change Variance Account
	Earnings Sharing Mechanism Deferral Account
	Mean Daily Volume Mechanism Deferral Account
	Electric Program Earnings Sharing Deferral Account
	Ex-Franchise Third Party Billing Services Deferral Account
	Purchased Gas Variance Account
	Transactional Services Deferral Account
	Unaccounted for Gas Variance Account
	Storage and Transportation Deferral Account

Company	Deferral Accounts
Union Gas	TCPL Tolls and Fuel
	North Purchase Gas Variance Account
	South Purchase Gas Variance Account
	Spot Gas Variance Account
	Unabsorbed Demand Cost Variance Account
	Investory Revaluation Account
	Short Term Storage & Exchange Balancing
	Long Term Peak Storage
	Lost Revenue Adjustment Mechanism
	Unbundled Servies Unauthorized Storage Overrun
	DSM Variance Account
	Gas Distribution Access Rule (GDAR) Costs
	Late Payment Penalty Litigation
	Shared Savings Mechanism Variance
	Carbon Dioxide Offset Credits Deferral Account
	Average Use Per Customer
	CGAAP to IFRS Conversion Cost
	Cumulative Under-Recovery-St. Clair Transmission Line
	Impact of Removing St. Clair Transmission Line from Rates
	Conservation Demand Management
	Harmonized Sales Tax
Northwest Natural	Decoupling (OR)
	Environmental Remediation
	System Integrity Program (SIP) (OR)
	Lost and Unaccounted for Gas
	Gas Cost Recovery
	OPEB
	Pension
	Removal Costs
	Storm Damage
	Weather Normalization (OR)
Piedmont Natural Gas	Bad Debt
	Rate Stabilization Tariff (SC)
	Conservation
	Decoupling (NC)
	Environmental Remediation
	Pipeline Integrity Expense (NC)
	Lost and Unaccounted for Gas
	Gas Cost Recovery
	OPEB
	Pension
	Removal Costs
	Weather Normalization (SC, TN)
WGL Holdings	Conservation and Ratemaking Efficiency Plan (CARE) (VA)
	Decoupling (MD)
	Fixed Cost Recovery Rate Design (MD, VA)
	Infrastructure Replacement Programs (VA)
	Lost and Unaccounted for Gas
	Gas Cost Recovery
	OPEB
	Pension
	Weather Normalization (VA)

Attachment 204.1

Decision 2004-052

Generic Cost of Capital

AltaGas Utilities Inc.
AltaLink Management Ltd.
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta (formerly Aquila Networks)
NOVA Gas Transmission Ltd.

July 2, 2004

Alberta Energy and Utilities Board

On balance, the Board concludes that the results of the ERP tests other than CAPM would generally support a 2004 ROE above the Board's CAPM estimate, but that for the reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM.

4.2.5 Discounted Cash Flow Test

The Board notes from Table 2 that the Applicants' standard-method DCF estimates for ROE ranged from 10.3-14.1%. The Board notes ATCO's argument that any upward bias in analyst growth estimates may be less prevalent for stable industries including utilities. Nevertheless, the Board considers that there is merit in the intervener arguments[56] that the analysts' earnings forecasts used in the development of the DCF estimates have been biased high, resulting in DCF estimates that overstate the required return. The record of the Proceeding reveals no evidence on an appropriate discount to apply to the DCF test results to appropriately adjust for an overstatement in the required returns. Accordingly, the Board finds reliance on the Applicant's DCF estimates problematic.

The Board notes that Dr. Booth's DCF approach[57] was not based on an assessment of analysts' earnings forecasts, but was based on an assessment of the growth of the overall economy. Dr. Booth considered that the market as a whole would grow at the same rate as the nominal GDP growth rate of about 6%, which would indicate a total investor market return of 8.5% after including average dividends of 2.5% (which included an estimated 0.5% to account for share repurchases as surrogate dividends). Dr. Booth indicated that this was a geometric market return estimate and therefore under estimated the average short-run growth rate, since the arithmetic rate exceeds the geometric rate. Dr. Booth further indicated that his DCF analysis confirmed that an 8.12% allowed ROE for a regulated utility was fair and reasonable. However, the Board notes that Dr. Booth did not quantify the impact of converting from a geometric rate to an arithmetic rate, did not quantify, in this case, the impact of utilities having less risk than the market average, and did not add an allowance for flotation costs.

As a result of the above noted concerns, the Board concludes that no weight should be placed on the results of the DCF tests presented in this Proceeding.

4.2.6 Comparable Earnings Test

The Board notes that several Applicants indicated that the comparable investment test, envisioned in the court decisions referred to in Section 3 of this Decision, obligated the Board to place weight on the CE test.[58] However, in the Board's view, the CE test is not equivalent to the comparable investment test. The CE test measures **actual** earnings on **actual book value** of comparable companies, which, in the Board's view, does not measure the return "*it **would** receive if it **were** investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise*"[59] (emphasis added) (unless the securities were currently trading at book value). The Board notes that Cargill[60] expressed a similar view.

56 For example, Cargill Argument, page 23, and CG Argument, page 13
57 Exhibit 016-11(a), Evidence of L.D. Booth, page 36
58 ATCO Argument page 8, Companies Argument page 24
59 NUL, 1929, at 192-193
60 Cargill Argument, pages 6 and 7

The Board considers that the application of a market required return (i.e. required earnings on market value) to a book value rate base is appropriate in the context of regulated utilities.

The Board notes Ms. McShane's CE test result of "no less than 13%". The Board notes that this result is in excess of Ms. McShane's 11.75% estimate of the market return, excluding flotation allowance, incorporated in her CAPM result in Table 3. The Board also notes Dr. Booth's evidence that at no time in the last fourteen years has the average ROE of Corporate Canada exceeded 12.0%, and only twice in the last thirteen years has the average ROE been in double digits.[61]

In the Board's view, based on Dr. Booth's evidence regarding the achieved ROEs of Corporate Canada, and her own CAPM estimate, Ms. McShane's CE test result of "no less than 13%" exceeds a reasonable forecast of the prospective market required return. In the Board's view, CE test results for low risk companies, that exceed the forecast required return on the overall market, raise serious conceptual or methodological concerns regarding the relevance of the CE test. The Board does not consider it reasonable for the prospective required return on low risk firms to exceed the prospective overall market required return. The Board notes Ms. McShane's evidence that lower risk firms have outperformed the market over certain historical periods. However, in the Board's view, to forecast this result would not be credible.

The Board also notes that, in this Proceeding, various implementation problems with the CE test were discussed. These included sample selection problems, accounting differences, market power concerns, and problems matching the current business cycle stage. The Board recognizes that all traditional ROE tests suffer from methodological difficulties.

The Board concludes that it should place no weight on the CE test because of the implementation problems of the CE test and the above-noted conceptual and methodological concerns with the CE test.

4.2.7 Other Measures of Comparable Investment

Although the Board will not place any weight on the CE test, the Board considers that there may be other measures of comparable investment that should be considered in the establishment of an appropriate ROE. In this section, the Board will address other such measures of comparable investment that were raised in the Proceeding.

Return Awards for Other Canadian Utilities

The Board acknowledges the potential for circularity when considering awards by other regulators. Nevertheless, the Board considers that awards by other Canadian regulators may provide some indication of the appropriate ROE for the Applicants.

[61] Calgary/CAPP Argument, page 6

Alberta Utilities Commission

2009 Generic Cost of Capital

November 12, 2009

279. Drs. Kryzanowski and Roberts did not provide a comparable earnings test because they state that "it is of dubious scientific merit ...and thus unsuitable for use in determining a fair ROE for a utility." They argued that there is neither any theoretical underpinning nor any empirical support for the comparable earnings method for estimating a regulated fair rate of return for a utility. In their view, "as an accounting-based measure, comparable earnings will only coincide with the investor's opportunity cost (required rate of return) by accident. There is no conceptual reason to expect that comparable earnings represent a rational expectation of an investor's desired rate of return from investing in the firm."[241]

280. In Decision 2004-052, the Board rejected the comparable earnings test results as a measure of return on a comparable investment.

> The CE [comparable earnings] test measures **actual** earnings on **actual book value** of comparable companies, which in the Board's view does not measure the return "*it **would** receive if it **were** investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise*" (emphasis added) (unless the securities were currently trading at book value).[242]

281. The Commission agrees with the Board that the comparable earnings test examines accounting earnings on book value for companies, but not returns actually available to, or required by investors in the market. In the Commission's view, because the comparable earnings test does not deal with returns available to investors in capital markets, it is not consistent with the comparable investment standard and is not a test upon which any weight should be placed. Consequently, the Commission will not consider the comparable earnings evidence.

5.5 Returns Awarded by Other Regulators

282. With respect to awarded returns for other Canadian utilities, a number of the utilities[243] argued that taking into consideration awards from regulators employing an adjustment mechanism similar to that used by the Commission would be circular. Accordingly, they recommended that the Commission place no weight on these awards. Mr. Coyne stated that:

> In Canada, the majority of utilities are bound by the same ROE formula, as are the utilities in Alberta, which is linked to the change in government bond yields. To evaluate the fairness of those ROE awards by looking to other Canadian utilities is analogous to looking in the mirror to compare your appearance to the reflection's. The potential for circularity of such a benchmarking analysis renders it, for the most part, meaningless as an independent source of comparability.[244]

283. CAPP took the position that awards by other regulators, in both Canada and the U.S., should not be considered:

> ... reference to either sets of decisions – Canadian and U.S. – as benchmarks of what is a fair return is unnecessary since the better approach is to examine the evidence of required returns estimated by experts using techniques founded on sound principles of finance.[245]

241 Exhibit 179.02, Evidence of Drs. Kryzanowski and Roberts, page 324.
242 Decision 2004-052, page 23.
243 AltaLink, EPCOR utilities, FortisAlberta and ATCO utilities.
244 Written Evidence of Mr. Coyne, Exhibit 50.01, Section 3.0, page 41.
245 Written Argument of CAPP, Exhibit 388.02, paragraph 403.

Decision 2003-061

AltaLink Management Ltd. and TransAlta Utilities Corporation

Transmission Tariff for May 1, 2002 – April 30, 2004

TransAlta Utilities Corporation

Transmission Tariff for January 1, 2002 – April 30, 2002

August 3, 2003

Alberta Energy and Utilities Board

- AltaLink placed a 50% weight on market risk premium method to calculate its requested rate of return. The interveners placed 100% weight on this methodology, although they used different variations of this methodology to reach their conclusions. The key difference between the AltaLink's and the interveners' use of the risk premium methodology is in the choice of parameters and variables in the model. In particular, the two parties are quite far apart in their estimates of the market risk premium.
- Both AltaLink and interveners included a flotation cost/equity issuance costs in their rates of returns, although there was a difference of opinion on the magnitude of the flotation cost.
- AltaLink and interveners are in broad agreement on the risk-free rate of return, and on the relative risk of AltaLink as measured by its beta factor.

Based on the evidence presented regarding the equity rate of return, the Board notes that the market risk premium estimates and adjustment add-ons are the primary reason why the applicant and intervener recommendations on rate of return are relatively far apart.

In determining the appropriate fair rate of return for AltaLink, the Board will address the following:

- Review of the Comparable Earnings Method
- Review of the Equity Risk Premium Method
- Review of the Flotation Cost Allowance
- Ability to Attract Equity Capital
- AltaLink's Fair Equity Rate of Return

For convenience of the electronic reader, the list above is hyperlinked to the section containing the detailed explanations of each topic.

11.4.1 Review of the Comparable Earnings Method

As noted above, AltaLink placed a 50% weight on the comparable earnings method in estimating its recommended rate of return on equity. In principle, the comparable earnings method relies on the premise that a firm that is relatively comparable to other firms in terms of risk, size, industry, etc. ought to earn a similar rate of return in competitive markets. Therefore, proponents of this approach believe that regulatory tribunals can benefit from reviewing the actual rates of return of close-substitute firms when setting the rate of return for utilities that they regulate.

The Board considers that the comparable earnings test is subject to major limitations. The test is sensitive to accounting practices of the sample firms, the sample selection, the selected business cycle and discontinuities caused by mergers, divestitures and restructuring. For example, the method is subject to arbitrary sample selection biases that utility companies can use to their benefit by picking comparable firms that are low risk and high earners. Further, when the comparable earnings method is applied, utility companies sometimes produce a sample containing firms with market power resulting in a situation that regulation is designed to avoid. In particular, the Board notes that AltaLink's comparable firms sample contained large industrial firms on the TSE 300, with low debt ratios. However, the Board notes that AltaLink made no effort to demonstrate that these firms were indeed close substitutes of AltaLink in terms of assets, size, or systematic risk. In addition, low performers were discarded from the sample, leaving a group of firms with high ex-post performance. In the Board's view, this clearly biases the forward-looking expectations investors would have held at the beginning of the measurement period.

Accordingly, for all of the above reasons, the Board continues to consider that the comparable earnings method is not appropriate and, hence, gives no weight to the comparable earnings method in this proceeding for the purposes of determining the appropriate equity rate of return.

11.4.2 Review of the Equity Risk Premium Method

The Board considers that there are major differences between AltaLink and the interveners' evidence on rate of return. First, both start with quite different estimates of the market risk premium. Calgary submitted that the market risk premium is 4.50%, while AltaLink recommended a market risk premium of 5.75%. The Board notes that the mid-point of these recommendations is 5.125%.

The Board notes that AltaLink's 5.75 % market risk premium is based partly on a study completed by Ibbotson and Associates. AltaLink also asserts that its risk premium estimate has been validated elsewhere, notably in CRTC Decision 2002-43 and in Quebec Regie de l'energie, Decision D-99-11. The range of the market risk premium estimates is 6.0-6.5% based on the findings in the two decisions. However, the Board observes that in those decisions, the market risk premium estimates include a significant weight with regard to U.S. risk premium estimates.

In comparison, according to NEB RH-4-2001, the market risk premium is in the range of 5.5-6.0%. AltaLink's estimate is within this estimated range. In contrast, on the lower end of the range, the Board notes that Calgary has recommended 4.5% as its best estimate of the expected market risk premium, based primarily on the historical record. In addition, Calgary's expert witnesses have argued that the forward-looking market risk premium is lower than the historical realized value.

The Board considers that based on the evidence presented by Calgary and AltaLink, the market risk premium estimate is within the range of 4.5% to 6%. In line with this determination, the Board's point estimate for the market risk premium is 5.3%.

The Board accepts AltaLink's beta estimate of 0.55 in order to calculate the appropriate equity risk premium. The Board notes that using Calgary's beta of 0.50 would result in a bare-bones cost of equity of 8.65%, only 25 bp less than AltaLink's estimate. The Board recognizes the difficulty in precisely estimating equity betas, and finds the applicant and intervener estimates reasonably close. Therefore, the Board will adopt AltaLink's beta estimate.

Accordingly, the Board concludes that an equity risk premium of 2.9% (5.3% x 0.55) is appropriate for the purpose of determining the fair equity rate of return for AltaLink.

11.4.3 Review of the Flotation cost allowance

Historically the Board has awarded 50 bp for flotation costs.

The Board notes that AltaLink has requested that the flotation cost allowance be increased to 75 bp to compensate for what it considers to be recent increases in the volatility of the market. However, AltaLink has provided no evidence to show that Canadian equity prices as a group have become more volatile in recent years.

THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

<u>DECISION 13-2007</u> **<u>August 29, 2007</u>**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided to its customers within the Northwest Territories.

benchmark returns would have the effect of rewarding NTPC twice for the same incremental risk that is already reflected in the capital structure of an average-risk utility.

> "When she estimates the risk premium, she incorrectly uses a sample or an industry index, which is really for an average and not low-risk utility. Recognizing her error, Drs. Kryzanowski and Roberts challenged her view that an incremental equity risk premium is required. Such an equity risk premium would have the effect of rewarding NTPC twice for the same incremental risk that is already reflected in the capital structure of an average-risk utility." (HC Reply, p. 21)

Views of the Board

The Board notes the CE method provides a measure of the actual realized returns on the book value of comparable risk securities. In this regard the CE test differs from other tests such as the equity risk premium test, which attempt to measure the expected return on the market value of securities. In an original cost rate base jurisdiction where the fair return is established on the basis of the book value of assets, the awarded returns must reflect investors' expectations of market returns on comparable risk securities. These expectations of market returns cannot, in the Board's view, be measured by the book returns of comparable risk securities because of differences between the book values and market values. Rather, the investors' expectations are appropriately measured in relation to the market value of comparable risk securities. In the Board's view the CE method fails to meet this requirement. Therefore the Board will not give any weight to the CE method in determining the fair return on equity.

The Board notes the DCF test, similar to other tests, has certain drawbacks. However, in view of the mitigating factors referred to by Ms. McShane, the Board

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

TERASEN GAS INC. AND
TERASEN GAS (VANCOUVER ISLAND) INC.
APPLICATION TO DETERMINE THE APPROPRIATE RETURN ON EQUITY AND CAPITAL STRUCTURE AND TO REVIEW AND REVISE THE AUTOMATIC ADJUSTMENT MECHANISM

DECISION

MARCH 2, 2006

Before:

R.H. Hobbs, Panel Chair
R.J. Milbourne, Commissioner
A.J. Pullman, Commissioner

The Commission Panel notes that this issue received some attention during the AEUB generic hearing, but that it was not enough to convince the AEUB to change the 50 basis point flotation cost allowance used in recent decisions (Exhibit A3-1, p. 29).

The Commission Panel tends to agree that it is difficult to rationalize any flotation cost allowance since there was little, if any, evidence placed before it of utilities trading at market to book ratios, which would justify a flotation cost allowance addition to their return on equity. Elsewhere in this decision the Commission Panel addresses market to book ratios and the need to establish a fair rather than lowest possible return. Accordingly, the Commission Panel will not automatically add a 50 basis point surcharge to whatever return it deems appropriate, but will exercise its judgment each time.

6.4.6 DCF Test

The Commission Panel notes that the DCF test is the most widely used test by regulatory bodies in the United States. Of the three methodologies before it, the DCF test is the only one to use current and prospective data to derive its results. The major criticism of the DCF method is that it relies on analysts' forecasts, which may be biased upwards. The Commission Panel does not find Dr. Booth's comments helpful in that his observations mostly cover U.S. technology analysts and the scandal on Wall Street concerning inappropriate analyst behaviour in an investment banking milieu. The Commission Panel finds that Dr. Booth's use of DCF estimates for U.S. Utilities covered by Standard & Poors, which included "multi-utilities" and energy marketing firms, should not be used as representative of U.S. utility returns. The Commission Panel is more persuaded by Ms. McShane's evidence which compares Value Line and I/B/E/S forecasts and finds no upward bias in the latter. Accordingly, the Commission Panel will give weight to Ms. McShane's first DCF Test, which yielded an indicated return of 8.8 percent. The Commission Panel agrees that this is a "bare bones" cost of equity, to which the addition of a "pure" flotation allowance of 25 basis points is required.

6.4.7 Comparable Earnings

Ms. McShane continues her practice of including in her evidence a study of the returns on book equity earned by a sample of low risk Canadian industrials in the period 1993-2004. This would suggest that low risk companies in Canada are earning an average of approximately 13 percent on their book equity.

On cross-examination, Dr. Booth agreed that some of the "problems" with the CE test also appear in the process of setting rates under regulation, notably that both use an accounting rate of return; it is an average, not a marginal, return; it is based on historic book equity; and based on non-inflation adjusted numbers. This leaves the sample selection itself. The Commission Panel recognizes that the sample selection can lead to very different results, which is why regulatory bodies are reluctant to re-embrace Comparable Earnings.

Dr. Booth reminded the Commission Panel that the last jurisdiction in Canada to use Comparable Earnings used to adjust the results as follows:

> "And Dr. Cannon tended to be the board (sc OEB) witness and he would do comparable earnings with market-to-book adjustments. And stretching my memory, but Ms. McShane I think estimated correctly that you'd look at rates of returns and try to work out what these rates of returns from non-regulated first would be if they had to have a market to book ratio of 1.5 or 1.2, which was sort of the target for regulated firm" (T6: 935).

The Commission Panel believes that there is not enough evidence before it to determine if such an adjustment is merited or how it might be accomplished. The Commission Panel is of the view that for these reasons it can give little or no weight to Ms. McShane's CE test results. However, the Commission Panel is not convinced that the CE methodology has outlived its usefulness, and believes that it may yet play a role in future ROE hearings.

6.4.8 Conclusion

In the Commission Panel's view, the suitable return on equity for a benchmark low-risk utility is 9.145 percent, assuming a 30-year long Canada bond yield of 5.25 percent, for a premium of 3.895 percent.

6.5 Impact of the Commission Panel's Determination

6.5.1 Impact on TGI

The Commission Panel determines that TGI is the benchmark low-risk utility. For 2006 TGI's ROE will be 8.80 percent viz 9.145 minus (.75*(5.25-4.79), on an equity component of capital structure of 35 percent, which the Commission Panel earlier determined to be appropriate. Based on Exhibit B-13, the Commission Panel believes the impact on TGI's 2006 revenue requirement will be a net increase of $1.9 million over TGI's approved 2005 revenue requirements, as follows:

	$ million
Increase in capital structure to 35%	4.742
Decrease in ROE to 8.80% from 9.03%	(2.842)
	1.900