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September 29, 2011

Via Email
Original via mail

Ms. Alanna Gillis
Acting Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. (FortisBC) Residential Inclining Block (RIB) Responses to British Columbia Utilities Commission (BCUC) Information Requests No. 2

Please find attached FortisBC's responses to Information Request No. 2 received from the BCUC in the above noted proceeding.

If further information is required, please contact the undersigned at (250) 717- 0890.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

1.0 Reference: Exhibit B-5, BCUC IR 1.1 (b); Exhibit B-8, Response to Commission Panel IR Q4.2

Conservation Savings

In Response to BCUC IR 1.1 (b) FortisBC states that "it would be impossible to report actual conservation savings due to the fact that FortisBC Inc. (FortisBC) cannot measure how much incremental energy customers might have used if a RIB rate had not been in place."

In Response to Commission Panel IR Q4.2, FortisBC says that it has not developed a plan to calculate the savings resulting specifically from Residential Inclining Block (RIB) rates and to separate them from DSM savings. FortisBC says that developing the means to attain the information related to energy savings is premature before having a mandate for the rate.

1.1 Once the application for the implementation of RIB rate is approved by the Commission, will FortisBC be carrying out plans to monitor the expected energy savings and analyze the impact of the RIB rate on customers' bills and the company's gross revenue? How does FortisBC plan to gain experience from implementing the RIB rate?

<u>Response:</u>

Assuming that a RIB rate is approved by the Commission, the Company intends to develop a plan to monitor and estimate the conservation impacts that can be attributed to RIB implementation, as well as any financial impacts to customers generally, and to FortisBC. This activity will allow the Company to suggest program changes to ensure that results are aligned with the objectives of the rate. After the planned roll-out of its Advanced Metering Infrastructure (AMI) program, it would be prudent to undertake an evaluation of rates and rate design in general, including all conservation rates will be undertaken after a further 2-3 years. The period between the approval and implementation of the RIB rate will be used to formulate the monitoring and evaluation plan.

1.2 FortisBC will have between six to nine months to implement the RIB rate. Will this time be used to devise a plan on how to study the RIB rate impact?

<u>Response:</u>

Please see the response to BCUC IR2 Q1.1 above.

1.3 BC Hydro applied to the Commission to use a RIB rate control group as a means of comparing the energy consumption patterns of customers on a flat rate to those on a RIB rate as one of several methods for measuring the effectiveness of the RIB rate. The Commission approved this application by Order G-160-08A. Given the lack of readily available research results on multi-tier rates, will FortisBC apply to the Commission, as soon as a RIB rate is approved, to create a control group for the analysis of the impact of RIB rate on its energy savings and gross revenue? If not, please explain why not.

Response:

Given the Company's understanding that the likely Commission direction on a RIB rate would include implementation as a default residential rate, a control group was not previously considered by FortisBC. FortisBC is of the opinion that it is premature to commit to any single element of the monitoring and evaluation program that will be developed as discussed in the response to BCUC IR3 Q1.1 above. Such a control group may form part of the program, but that cannot be predetermined.

2.0 Reference: Exhibit B-8, Response to Commission Panel IR Q1.0

Analysis of Bill Impact by Option

Table BCUC IR2 Q1.1b shows that under the preferred Option 8, customers who will experience over 10% bill impact are those whose annual usage is above 28,000 kWh. It also shows that those customers who will experience over 20% bill impact are those with annual usage above 100,000 kWh.

2.1 Please confirm that the third column of Table BCUC IR2 Q.1.1b actually refers to "# of customers". If not, please explain how to interpret the "# of bills" with the range of "annual consumption" data in the first two columns.

Response:

Confirmed.

2.2 In order to better understand the customers who will have a bill impact of 10% or higher, please provide more information regarding these customers' usage and bill impact:

- The number of customers who have usage: 1) over 28,000 kWh (and their percentage share of the total number of customers); 2) over 40,000 kWh (and their percentage share of the total number of customers); 3) over 50,000 kWh (and their percentage share of the total number of customers); 4) over 100,000 kWh (and their percentage share of the total number of customers); and 5) over 150,000 kWh (and their percentage share of the total number of customers).

- The change in total bill (in $ and % amounts) for the average customer in each of these groups above (e.g., the average customer over 28,000 kWh, the average customer over 40,000 kWh, etc.)

Response:

Please see the following tables.

Table BCUC IR2 Q2.2a

Annual Usage	Number of Customers	Percent of Customers	Average Annual Bill Change	Average Percent Bill Change
5,000-6,000 kWh	6,225	7.11%	-$68	-10%
Over 28,000 kWh	4,534	5.18%	+$628	+15%
Over 40,000kWh	1,624	1.86%	+$1,110	+18%
Over 50,000 kWh	888	1.01%	+$1,496	+19%
Over 100,000 kWh	134	0.15%	+$3,517	+22%
Over 150,000 kWh	46	0.05%	+$5,984	+23%

Table BCUC IR2 Q2.2b

	5000-6000 kWh per year	Over 28,000 kWh per year
Single-Family House	58.7%	89.7%
Other Type of Dwelling	41.3%	10.3%
Electric Heat	25.4%	69.0%
Other Heat	74.6%	31.0%
Income <$20k	8.5%	4.3%
Income $20k-$40k	35.6%	8.7%
Income $40k-$60k	20.3%	30.4%
Income $60k-$80k	22.0%	17.4%
Income $80k-$120k	13.6%	21.7%
Income >$120k	0.0%	17.4%

The majority of high usage customers live in single-family homes while the customers in the 5,000-6,000 range are equally likely to live in a different type of dwelling. The Company does not have a further breakdown between apartments, condos, mobile homes or duplexes.

The presence of electric heat is highly correlated with customers that have usage over 28,000 kWh per year, and electric heat is not necessarily associated with high incomes. A higher income level is less correlated with high usage compared to electric heat. Customers with usage of over 28,000 kWh will see average increases of 15%, yet 43% of these customers have incomes of $60,000 per year or less. Customers with average usage between 5,000 and 6,000 will see an average decrease of 10%, yet 35% of these customers have an income level above $60,000 per year. It is clear from these results that many low income customers will see significant bill increases while rate decreases will often flow to high income customers.

2.3 According to Table BCUC IR2 Q 1.1b, customers consuming at between 5,000 to 6,000 kWh will benefit the most from the implementation of RIB under Option 8. Please provide the total number of customers, the percentage share of this group of customers, and their average decrease in bills.

<u>Response:</u>

Please see the response to BCUC IR2 Q2.2 above.

2.3.1 Please provide the profile in dwelling type of this segment, e.g., percentage in single detached home, apartment/condo, mobile home, duplex, etc.

<u>Response:</u>

Please see the response to BCUC IR2 Q2.2 above.

2.3.2 What is the income profile of this group of customers?

<u>Response:</u>

Please see the response to BCUC IR2 Q2.2 above.

2.3.3 If the median and mean consumption levels at FortisBC are respectively 1,600 kWh and 2,100 kWh per month, how many customers consuming at an average of 400 to 500 kWh per month (5,000 to 6,000 kWh annually) use electric space heating and/or cooling?

Response:

Please see the response to BCUC IR2 Q2.2 above. The Company does not have information specific to air conditioning.

2.3.3.1 Does FortisBC have any findings from DSM program evaluation or other end use surveys that show customers at this level of consumption have fewer opportunities to respond to price signals?

Response:

FortisBC does not have specific findings regarding the high consumption customers. However, as the response to BCSEA IR2 Q28.1 shows, 38% of customers overall have having electric space heating as their primary heating source, while 77% of customers with consumption above 18,000 kWh have electric heat. The high level of electric space heating penetration in the high-consumption group may result in a higher elasticity of demand since there are effective inexpensive (turning down the thermostat, for example) and more costly (such as switching to natural gas) measures to control demand.

2.3.3.2 Are there plans at FortisBC to better understand the consumption pattern of this segment who, as a result of the implementation of RIB, will be paying Block 1 rate that will be lower than the current rate?

Response:

As discussed in the response to BCUC IR2 1.1 above, the scope of any monitoring and evaluation process has not been defined prior to the approval of the RIB rate. The answer to the query is, no – not at this time. However, within the ultimate design of an evaluation program, considerations such as those contemplated by the question can be included for discussion.

3.0 Reference: Exhibit B-8, Commission Panel IR Q4.1 & Q5.2

Interaction of DSM and RIB

FortisBC says that it does not have any sources of data to determine how RIB rates and DSM programs will interact in the future. It further states that the expected savings for RIB rates and the DSM program targets were prepared independently.

FortisBC says that it will adjust its DSM programs as well as load forecasts as required and as it gains experience with RIB rates.

3.1 In Exhibit B-5, BCUC IR 9.3, FortisBC presents two scenarios – with and without RIB Program of "Gross load after DSM and other Customer Savings". The difference of the two scenarios is 3.1 GWh for the year 2012. Please confirm that RIB savings in Table BCUC IR 9.3 are estimated to be 3.1 GWh.

<u>Response:</u>

The after-losses RIB savings for 2012 are confirmed to be 3.1 GWh. The following tables are reproduced from the Company's response to BCUC IR1 Q231.4 in its 2012-2013 Revenue Requirements application.

Table BCUC IR2 Q3.1a

Residential Non-DSM Savings - Before Losses (MWh)					
Year	RIB	AMI	CIP	Total	AMI Loss
2011	-	-	-	-	-
2012	2,842	-	-	2,842	-
2013	7,861	(2,286)	-	5,574	2,286
2014	13,077	(4,662)	-	8,414	4,662
2015	18,499	(7,132)	2,038	13,404	7,132
2016	24,120	(9,694)	4,155	18,581	9,694
2017	26,805	(12,344)	4,232	18,693	12,344
2018	27,294	(10,056)	4,310	21,548	12,570
2019	27,780	(7,676)	4,386	24,490	12,793
2020	28,264	(5,206)	4,463	27,520	13,016
2021	28,747	(2,648)	4,539	30,638	13,239
2022	29,228	-	4,615	33,843	13,460
2023	29,708	-	4,691	34,399	13,681
2024	30,188	-	4,767	34,954	13,902
2025	30,667	-	4,842	35,510	14,123
2026	31,142	-	4,917	36,059	14,342
2027	31,611	-	4,991	36,602	14,558
2028	32,076	-	5,065	37,141	14,772
2029	32,538	-	5,138	37,676	14,985
2030	32,994	-	5,210	38,203	15,195
2031	33,446	-	5,281	38,727	15,403
2032	33,898	-	5,352	39,250	15,611
2033	34,346	-	5,423	39,769	15,817
2034	34,791	-	5,493	40,284	16,022
2035	35,232	-	5,563	40,795	16,225
2036	35,670	-	5,632	41,302	16,427
2037	36,105	-	5,701	41,806	16,627
2038	36,536	-	5,769	42,305	16,826
2039	36,965	-	5,837	42,801	17,023
2040	37,389	-	5,904	43,293	17,219

Table BCUC IR2 Q3.1b

Residential Non-DSM Savings - After Losses (MWh)				
Year	RIB	AMI	CIP	Total
2011	-	-	-	-
2012	3,117	-	-	3,117
2013	8,621	-	-	8,621
2014	14,342	-	-	14,342
2015	20,289	-	2,235	22,524
2016	26,455	-	4,557	31,011
2017	29,399	-	4,642	34,041
2018	29,935	2,514	4,727	37,176
2019	30,468	5,117	4,811	40,396
2020	30,999	7,810	4,895	43,703
2021	31,529	10,591	4,978	47,098
2022	32,057	13,460	5,062	50,579
2023	32,583	13,681	5,145	51,409
2024	33,110	13,902	5,228	52,240
2025	33,635	14,123	5,311	53,069
2026	34,156	14,342	5,393	53,891
2027	34,670	14,558	5,474	54,702
2028	35,180	14,772	5,555	55,507
2029	35,687	14,985	5,635	56,307
2030	36,187	15,195	5,714	57,095
2031	36,683	15,403	5,792	57,878
2032	37,178	15,611	5,870	58,659
2033	37,670	15,817	5,948	59,435
2034	38,158	16,022	6,025	60,205
2035	38,642	16,225	6,101	60,968
2036	39,122	16,427	6,177	61,727
2037	39,599	16,627	6,253	62,479
2038	40,073	16,826	6,327	63,226
2039	40,542	17,023	6,401	63,967
2040	41,008	17,219	6,475	64,702

3.1.1 Please explain the calculation method and assumptions used to arrive at 3.1 GWh of RIB savings.

Response:

For the purpose of estimating the RIB savings, the 1.9% conservation impact from the Company's proposed option was assumed to be fully realized by 2017, with 0.2217% occurring in 2012. The Company notes that these assumptions were made in order to respond to the original question and in practice; it has no method for determining how much of the estimated savings would result in any given year.

The detailed calculations are as follows:

1,282,058 Net Load * 0.002217 RIB 2012 Calculation Factor = 2,842 MWh RIB Savings before losses

2,842 * 1.0968 Loss Adjustment for Net Load = 3,117 MWh RIB Savings after Losses

Losses as a percentage of gross load are 8.82% but if only net load is known, losses must be expressed as a percentage of net load in order to calculate the gross load. Losses expressed as a percentage of net load are 9.68%.

3.1.2 Please confirm that the gross load of 3,502 GWh refers to all customer sectors. The residential sector load before DSM, to which the RIB rate is applicable, is 1,282 GWh in Year 2012 (Ref: Table A-1 from 2012-2013 Revenue Requirement Application and attached in Appendix).

Response:

3,502 GWh is the after DSM and Other Customer Savings total Company energy load forecast for 2012 and therefore it is confirmed that it includes all sectors. Please refer to the response to BCUC IR2 Q3.2 below for a discussion of the residential sector load forecast.

3.2 In Exhibit B-5, BCUC IR 18.3, FortisBC presents its residential DSM savings target for 2012 as 16.1 GWh. Please confirm that according to the load forecasts for residential customers with and without DSM, the forecast for 2012 is 1,282 GWh without DSM and 1,264 GWh with DSM, resulting in a difference of 18 GWh in DSM savings (Ref: Tables A-1 and A-2 from 2012-2013 Revenue Requirement Application and attached in Appendix).

Response:

This is not correct. As stated in the 2012-2013 Revenue Requirements Application Tab 3, Section 3.3, all DSM numbers used in the application include the effects of both DSM and the other savings adjustments such as for RIB. However, these have been broken out in response to BCUC IR1 Q231.4 of the 2012 - 2013 Revenue Requirement application which is reproduced here.

Table BCUC IR2 Q3.2

Cumulative DSM Energy Break-out (MWh)

Year	Residential	Commercial	Wholesale	Industrial	Lighting	Irrigation	Net	Loss	Gross
2010	-	-	-	-	-	-	-	-	-
2011	5,432	4,066	4,495	1,243	373	343	15,952	1,544	17,496
2012	15,431	11,549	12,769	3,530	1,059	873	45,212	4,376	49,587
2013	24,457	19,224	20,674	5,876	1,763	1402	73,396	7,103	80,499
2014	33,762	27,136	28,823	8,295	2,488	1969	102,474	9,917	112,391
2015	43,831	35,698	37,640	10,911	3,273	2580	133,934	12,962	146,896
2016	54,443	44,722	46,934	13,670	4,101	3223	167,093	16,171	183,264
2017	63,844	52,716	55,167	16,113	4,101	3773	195,715	18,941	214,656
2018	72,009	59,658	62,317	18,235	4,101	4265	220,586	21,348	241,935
2019	80,173	66,601	69,467	20,357	4,101	4758	245,458	23,756	269,213
2020	88,338	73,543	76,617	22,479	4,101	5250	270,329	26,163	296,492
2021	96,502	80,486	83,767	24,602	4,101	5742	295,200	28,570	323,770
2022	104,667	87,428	90,917	26,724	4,101	6235	320,072	30,977	351,048
2023	112,831	94,371	98,067	28,846	4,101	6727	344,943	33,384	378,327
2024	120,996	101,313	105,217	30,968	4,101	7219	369,815	35,791	405,605
2025	129,160	108,256	112,368	33,090	4,101	7712	394,686	38,198	432,884
2026	137,325	115,198	119,518	35,212	4,101	8204	419,557	40,605	460,162
2027	145,489	122,141	126,668	37,334	4,101	8696	444,429	43,012	487,441
2028	153,654	129,083	133,818	39,456	4,101	9189	469,300	45,419	514,719
2029	161,818	136,026	140,968	41,578	4,101	9681	494,171	47,826	541,998
2030	169,983	142,968	148,118	43,700	4,101	10173	519,043	50,233	569,276
2031	178,147	149,911	155,268	45,822	4,101	10665	543,914	52,640	596,555
2032	186,312	156,853	162,418	47,944	4,101	11158	568,786	55,047	623,833
2033	194,476	163,796	169,568	50,066	4,101	11650	593,657	57,454	651,111
2034	202,641	170,738	176,718	52,188	4,101	12142	618,528	59,862	678,390
2035	210,805	177,681	183,868	54,310	4,101	12635	643,400	62,269	705,668
2036	218,970	184,623	191,018	56,432	4,101	13127	668,271	64,676	732,947
2037	227,134	191,566	198,168	58,554	4,101	13619	693,142	67,083	760,225
2038	235,299	198,508	205,318	60,677	4,101	14112	718,014	69,490	787,504
2039	243,463	205,451	212,468	62,799	4,101	14604	742,885	71,897	814,782
2040	251,628	212,393	219,618	64,921	4,101	15096	767,757	74,304	842,061

The 2012 Residential before losses DSM number used in the load forecast was 15,431 MWh. This is a cumulative number composed of the 5,432 MWh from 2011 and a further 9,999 MWh for 2011. The difference between 9,999 MWh and 16.1 GWh is one of timing since, for example, DSM undertaken in December will only impact 2012 load for one month of the year but will be counted in full for the DSM program.

3.2.1 The difference between the 16.1 GWh used in this proceeding and the 18.0 GWh in the load forecasting is 1.9 GWh or 11.8%. Is this discrepancy a result of adjustment of transmission and distribution losses? If not, please explain the discrepancy.

Response:

Please refer to the response to BCUC IR2 Q3.2 above.

3.3 In Exhibit B-5, BCUC IR 19.2, FortisBC presents the estimated savings of the RIB rate for 2012 for Option 8, at an assumed elasticity of 0.05/0.10, to be 23.591 GWh or 1.9%, out of a range of 8.9 GWh to 41.9 GWh among the original 18 options.

3.3.1 Please reconcile the 23.591 GWh of residential energy savings with the 3 GWh from BCUC IR 9.3 in Exhibit B-5.

Response:

The 23.591 GWh represents the 1.9% long-term savings that will occur from the proposed RIB rate. The total GWh savings are calculated on the basis of the 2011 residential load. While it is based on 2011 usage and rates, it does not imply that the full amount will be achieved in 2011.

The 3 GWh savings represents 2012 in particular, with the remainder of the 1.9% savings achieved over subsequent years.

3.3.2 Please explain the decision to adopt the 3 GWh energy savings attributable to RIB in the 2012-2013 RRA (page 3C-2 attached in Appendix).

Response:

The 3 GWh in 2012 attributed to RIB in the 2012-2013 was based on the adoption of Option 8 at an assumed elasticity of 0.05/0.10. The total long-run savings of 23.6 GWh were not assumed to occur immediately in 2012, but were phased in over 5 years.

3.3.3 Is it reasonable to conclude that the 23.6 GWh savings from the implementation of RIB will come from the 25% of residential customers who consume over the breakeven point of 15,000 kWh per year (Exhibit B-1, Table 7-2)? If not, please explain why not.

Response:

FortisBC employed the same methodology used by BC Hydro to estimate price impacts in the BC Hydro RIB analysis and application. This analysis assumed that if a customer experiences any consumption in the second tier then the entire consumption will be subject to price elasticity impacts. Thus it is not reasonable to assume that the 23.6 GWh comes only from customers who consume over the breakeven point.

3.3.4 How much energy in total (GWh) do these 25% of customers consume in 2012? What is the percentage of the estimated savings of 23.6 GWh to this total?

Response:

The roughly 25% of customers that have usage over 15,000 kWh per year consume 529,150 MWh, which is 52% of the total residential consumption. The 23.6 GWh estimated savings represents 4.5% of the consumption of these customers.

3.3.5 FortisBC created its PowerSense DSM program in 1989. Is FortisBC able to describe if any of its portfolio of residential DSM programs target specifically high-consumption customers? To the best of FortisBC's knowledge, are DSM programs or RIB rates more effective in saving energy in the high-consumption segment?

Response:

FortisBC does not have any PowerSense DSM programs targeted specifically at high-consumption customers. FortisBC does not have any information regarding the relative effectiveness of DSM programs and RIB rates for high-consumption customers.

3.3.6 FortisBC mentions that it will adjust its DSM programs and load forecasts as it gains experience with RIB rates. Please describe how.

Response:

Through the Monitoring and Evaluation function that is part of the PowerSense DSM program, FortisBC will continue to monitor the effectiveness of DSM programs. If the effectiveness of DSM programs changes materially (for example, free-ridership rates decrease), then PowerSense programs are adjusted accordingly (for example, programs are added or removed or incentive levels are changed).

4.0 Reference: Exhibit B-5, BCUC IR 6.2.1 & IR 6.3; Exhibit B-8, Commission Panel IR Q5.1.1

RIB and TOU Rates

FortisBC believes that energy savings from TOU rates is generally higher than the range of conservation estimates from RIB rates based on the Ontario Energy Board Smart Price pilot study it cited in its 2009 COS and RDA, which showed energy savings from TOU rates were 6%.

4.1 Do you agree that TOU rates are designed to target capacity savings rather than energy savings? If not, please explain why not.

Response:

FortisBC believes that the primary goal of time-based rates is to conserve capacity, but that energy conservation also occurs.

4.2 Do you agree that energy savings are incidental to TOU rates? If not, please explain why not.

Response:

Please see the response to BCUC IR2 Q4.1 above.

4.3 In BCUC IR1 6.2.1, FortisBC showed energy savings from TOU rates at 6.4%. This 6.4% can be traced from the Table BCUC IR1 Q6.2.1a (192,575 kWh) for Residential 2010 TOU energy savings and Table BCUC IR 1 Q6.2a (3,017,012 kWh) for Residential 2010 TOU Usage; where 192,575 divided by 3,017,012 equals 6.4%. Is it true that the high percentage in savings at 6.4% is a result of using a small base TOU usage base? If not, please explain why not.

Response:

The calculation used to obtain the savings 192,575 kWh in residential TOU savings was:

3,017,012 kWh / (1 - 0.06) – 3,017,012 kWh = 192,575 kWh

The savings were calculated in this way since the 3,017,012 kWh is the amount of usage after the effect of 6% conservation is assumed.

Therefore a 6% reduction was used in the calculation, so it is not true that 6.4% savings were used.

4.3.1 Given the TOU rate is on a voluntary basis and may attract customers who know they will benefit from this rate structure, please comment on the reasonableness of projecting energy savings of the same order (6.4%) if TOU was mandatory.

Response:

The (6.0%) TOU savings used are a rough estimate of time-based savings generally (the actual response will depend on a number of factors, particularly the design of the time-based rate). As indicated in BCOAPO IR2 8a, FortisBC would generally expect voluntary TOU savings to be less than mandatory TOU savings.

4.3.2 Although 6.4% savings estimated for TOU is higher than the 1.9% savings estimated for RIB, do you agree that comparing a TOU base of 3 GWh with a total base of 1,264 GWh does not logically lead to a conclusion that TOU rate provides conservation benefits which are at a minimum as good as a RIB rate? If not, please explain why not.

Response:

The assertion that time-based rates provide conservation benefits which are at minimum as good as a RIB rate is independent of the amount of load that is subject to each rate structure.

The assertion was made based on rough estimates of percentage energy savings for each type of rate structure. The actual savings from each rate structure are dependent on a variety of factors, particularly the specific design of each rate structure.

4.3.3 In Response to BCUC IR 6.4, FortisBC states that should a RIB rate be mandated by the Commission, it is currently the Company's intention to introduce a suite of time-based rates to complement the RIB rates, likely on a voluntary participation basis. Does FortisBC have any information on the likely participation rate and the energy consumption of this group of customers?

Response:

As the Company has not yet determined the nature of the time-based rates that may be developed, it cannot speculate on whether the individual rates will have a greater take-up than the TOU rates that are currently in place. It seems likely however that as some customers will be better off under the RIB rate without changing consumption habits, migration to a TOU rate will not be significant. FortisBC has not stated that it intends to offer a suite of TOU rates (as alluded to in IR 4.3.3.1 below). Rather, the intention is to offer a suite of time-based rates. At this preliminary stage, and without knowing the specifics on rate structures, the Company cannot predict participation rates or financial impacts.

4.3.3.1 If the TOU rate is on a voluntary basis and customers on the TOU rate are exempt from the mandatory RIB rate, the TOU rate may attract customers who know that they could benefit from this rate structure. What would be the impact on revenue requirements and rate to residential customers on the default RIB rate as a result of the introduction of a suite of TOU rates?

Response:

Please see the response to BCUC IR2 Q4.3.3 above.

4.4 In "Inclining Toward Efficiency" (Faruqui, 2008), it is noted on p. 26 that "Based on empirical estimates of price elasticity of different sources, inclining block rates can provide energy consumption savings in the 6 percent range over a few years and even higher savings over the long run."

4.4.1 Does FortisBC agree that the empirical evidence shows that energy savings from RIB rates structures are similar to those from TOU? If not, please explain why not.

Response:

The Company agrees that some studies show results consistent with the conclusions referenced in the preamble to the question. The Company notes that if the conclusion is drawn from the results of the study on the same page of the article that the 5.9% conservation results were achieved at a hypothetical utility with a block 1 rate less than 5 cents per kWh, a block 2 rate in excess of 15 cents per kWh and a threshold of 500 kWh. Whether these results could be expected at FortisBC is a matter for debate.

FortisBC supports the notion that a RIB rate will have a conservation impact. Whether RIB or time-based rates achieve more conservation is dependent on the underlying rates and rate structures, and assumptions regarding elasticity.

The RIB options presented in the Application and subsequent filings contain conservation impact estimates that for options with similar attributes are fairly uniform. Under certain elasticity assumptions, impacts beyond 6% are shown.

5.0 Reference: Exhibit B-11, Directive 2b, pp. 8-9; Exhibit B-11, Appendix B

Natural Conservation

On p. 8, FortisBC presents the projected rate increases as follows:

	2012	2013	2014	2015
RRA Increase	4.00%	6.90%	5.80%	11.40%
Rebalancing Increase	2.50%	2.30%	0.00%	0.00%

On p. 9, FortisBC states that "Because a certain amount of the rate increases by component will occur as a result of the projected general rate increases, independent of a RIB rate, the cumulative savings shown reflect a net amount associated with the RIB rate structure. This net amount is calculated by taking the total cumulative savings associated with each year and subtracting the expected savings that would occur under a flat block rate scenario."

5.1 Please provide, in tabular form, the annual amount of natural conservation (in percentage) that would occur in 2012, 2013, 2014 and 2015 only as a result of the projected general rate increases. Please also provide the calculations.

Response:

The natural conservation is shown in Appendix A Table 1 under the flat rate option, as shown below. For the RIB scenarios the cumulative savings represent the net amount associated from RIB rates, while for the flat rate option it reflects the cumulative natural conservation resulting from projected rate increases.

Elasticity Levels	2012	2013	2014	2015
.05/.10	0.6%	1.2%	1.6%	2.4%
.10/.20	1.1%	2.5%	3.1%	4.9%
.20/.30	1.7%	3.8%	4.8%	7.5%

These savings were estimated similarly to the savings for RIB rates. Rate increases were based on the nominal rate increases expected less the projected inflation rate of 2%. For usage below a threshold of 1350 was assumed to use the lower level of elasticity while usage above that threshold was assumed to use the higher elasticity level. This reflects the basic belief that elasticity is higher at higher consumption levels.

The following is an example of the calculation for the 2012 savings under the .05/.10 elasticity levels:

Step 1:

elasticity	*	real rate change	*	usage facing block 1	=	kWh savings
-.05	*	106%	*	162,778,725 kWh	=	487,454 kWh

Step 2:

elasticity	*	real rate change	*	usage facing block 2	=	kWh savings
-.10	*	106%	*	1,108,456,055 kWh	=	6,640,760kWh

Step 3:

block 1 kWh savings	+	block 2 kWh savings	=	total kWh savings
487,454 kWh	+	6,640,760 kWh	=	7,128,214 kWh

Step 4:

total kWh savings	/	total residential kWh	=	percent savings
7,128,214 kWh		1,271,184,789	=	0.6%

5.1.1 Is it fair to say that, for the 'reasonable' options (Exhibit B-11, Appendix B), the total amount of conservation is obtained by adding the level of natural conservation to the level of structural conservation presented in Appendix B?

Response:

For the options provided, the structural conservation was estimated by taking the total conservation estimates resulting from the projected rates for each year less the natural conservation. Therefore, by definition, the total conservation will equal the natural conservation plus the structural conservation.

5.2 Please confirm that the Load Forecast methodology presented in FortisBC's 2012-2013 Revenue Requirement Application also takes into account the natural conservation resulting from projected general rate increases, i.e., the gross load forecast is reduced by the amount of natural conservation. If not, please explain why not.

Response:

Natural conservation from rate increases is part of the overall historical average use per customer trends and is therefore taken into consideration.

6.0 Reference: Exhibit B-11, Directive 2b, p. 9; Directive 5a, p. 19; Directive 5b, pp. 19-20;

Exhibit B-5, BCUC 18.5, BCUC 18.7, BCUC 21.3

Short-Term versus Long-Term Elasticity

On p. 9 of Exhibit B-11, FortisBC states that "Elasticity values should be seen as long-term with the three elasticity scenarios representing varying degrees of customer response."

In "Price Elasticity of Demand for Electricity: A Primer and Synthesis" (EPRI, 2007), referenced in the response to Directive 5b of Exhibit B-11, Table 1 (copied below) summarizes the range of own-price elasticity reported in the nine selected studies.

Table 1. Own-price elasticities of electricity demand

	Short Run			Long Run		
	Mean	Low	High	**Mean**	Low	High
Residential	**-0.3**	-0.2	-0.6	**-0.9**	-0.7	-1.4
Commercial*	**-0.3**	-0.2	-0.7	**-1.1**	-0.8	-1.3
Industrial*	**-0.2**	-0.1	-0.3	**-1.2**	-0.9	-1.4

** The estimates for the commercial and industrial sector are from EPRI (2001).*

In "Inclining Toward Efficiency" (Faruqui, 2008), referenced in the response to Directive 5b of Exhibit B-11, Table 2 (copied below), residential price elasticities by block both for the short run and long run were estimated.

TABLE 1 DISTRIBUTION OF RESIDENTIAL PRICE ELASTICITIES

		Low	Most Likely	High
Short Run	Block 1	-0.01	-0.13	-0.20
	Block 2	-0.02	-0.26	-0.39
Long Run	Block 1	-0.03	-0.39	-0.60
	Block 2	-0.06	-0.78	-1.17

Previously, FortisBC stated that "the range of values used for elasticity are thought to be representative of a **reasonable range of short term price elasticity**". (Exhibit B-5, BCUC 18.5) (Emphasis added)

However, FortisBC further stated that "the range of elasticities shown are intended to be **reflective of different time periods of RIB rate implementation**. It is expected that price elasticity will be **less in the short term** since customer response will be largely behavioural. **Price response is expected to increase over longer periods** as customers choose more efficient energy-consuming devices." (Exhibit B-5, BCUC 18.7) (Emphasis added)

Finally, FortisBC stated that "the elasticity numbers used in the Application **are meant to be long-term** – they don't occur immediately." (Exhibit B-5, BCUC 21.3) (Emphasis added)

6.1 Please justify why FortisBC state on p. 9 of Exhibit B-11 that the elasticity values should be seen as long-term when the empirical evidence on price elasticity FortisBC has filed as supporting evidence distinguishes quite clearly between short run price response (driven primarily by behavioral changes) and long-run price response (driven mainly by equipment and building shell changes), even in an inclining block rate structure.

<u>Response:</u>

FortisBC is not implying when it says that its "elasticity values should be seen as long-term" that any time-series estimates of elasticity response should use only the long-term value. In fact, when FortisBC estimated the effect of the proposed RIB rate in its 2012-2013 Revenue

Requirement application, it assumed that the long-run 1.9% effect was only achieved after several years. This is because the short-run response is less than the long-run response.

FortisBC agrees that the response stating "the range of values used for elasticity are thought to be representative of a reasonable range of short term price elasticity" (Exhibit B-5, BCUC 18.5), while plausible, is not consistent with this approach.

6.2 Given the contradictory responses provided by FortisBC in its responses to IR No. 1 with respect to the three price elasticity scenarios, please clarify how to interpret the range of price elasticity scenarios provided by FortisBC in the RIB Rate Application.

Response:

Please see the response to BCUC IR2 Q6.1 above.

7.0 Reference: Exhibit B-11, Directive 2b, p. 9; Exhibit B-11, Appendix B; Exhibit B-6, OEIA IR 6.1

Cumulative Savings

On p. 9, FortisBC states that "Savings are shown on a **cumulative basis** for each of the 5 years." (Emphasis added)

FortisBC also states that "Further, the elasticity calculations for each year reflect eventual savings as a result of the rate change and will not necessarily all occur in the same year as the rate is changed. So while elasticity savings are shown by year, as requested, they reflect the savings that will occur over time associated with the change in rates for each year."

In the response to OEIA 6.1, FortisBC states that it has "assumed that it will achieve the 1.9 per cent residential energy savings outlined in Table 7-2 incrementally over the next 5 years with the proposed RIB rate structure".

7.1 Given the references above, please clearly explain how to interpret the results under the columns "**Cumulative Conservation** Impact from RIB" in Appendix B for the following two options:

- 8.1 (Option 8 and pricing principle 1):

Elasticity Estimate	Cumulative Conservation Impact from RIB				
	2011	2012	2013	2014	2015
.05/.10	1.9%	2.0%	2.1%	2.2%	2.4%
.10/.20	3.7%	4.0%	4.2%	4.4%	4.9%
.20/.30	5.5%	5.8%	6.2%	6.6%	7.3%

- 66.3 (Option 66 and pricing principle 3):

Elasticity Estimate	Cumulative Conservation Impact from RIB				
	2011	2012	2013	2014	2015
.05/.10	2.6%	2.4%	2.3%	2.3%	2.2%
.10/.20	4.9%	4.8%	4.7%	4.6%	4.5%
.20/.30	7.2%	7.1%	6.9%	6.8%	6.7%

Response:

Please see the response to BCUC IR2 Q7.1.1 below.

7.1.1 In particular, please reconcile the statement that 1.9% of conservation will be achieved over 5 years with Option 8.1 when the table above shows 1.9% in 2011 and 2.4% in 2015.

Response:

FortisBC believes that the statements are consistent and do not require reconciliation.

The "Option 8.1" table above shows the amount of conservation that would be achieved over the long-term from the rate implemented in each year shown. The reason the estimated long-term savings changes from year-to-year is that the underlying RIB rate is changing due to forecast rate increases.

In the response to OEIA IR1 Q6.1, FortisBC assumed that "long-term" was 5 years, and phased in the 1.9% impact over that time period (so that by the end of year 5 the full 1.9% effect was realized).

7.1.2 For Option 8.1, under the price elasticity scenario of .05/.10, is it fair to say that the table shows incremental conservation is 0.1% more in 2012 than in 2011 and 0.5% more in 2015 than in 2011? If not, please explain why not.

Response:

It is true that the calculated savings is 0.1% more for 2012 than for 2011 and that 2015 is 0.5% more than 2011 (in absolute terms). Again, this reflects long-term savings estimated for the rates implemented in those years (which vary due to forecast rate increases) and is not intended to reflect the savings that will occur in the given years.

7.1.3 For Option 66.3, under the price elasticity scenario of .05/.10, is it fair to say that the table shows conservation is at a maximum during the first year at 2.6% and subsequently decreases over time to a lower level of 2.2% in 2015?

Response:

It is true that for option 66.3 the long-term savings for the rates in 2015 are expected to be lower than the long-term savings expected for the rates in 2011. Please also see the response to BCUC IR2 7.1.2.

7.1.4 In particular, how do you interpret declining cumulative savings over time as in Option 66.3, as opposed to increasing cumulative savings as in Option 8.1? Please specify what factors could cause the cumulative savings to decline over time?

Response:

Long-term savings decline over time in Option 66.3 and in some of the other cases because the savings reflect the impact from RIB rates alone. Natural conservation resulting from the annual rate increases would occur with a flat rate as well and is subtracted from the total savings.

The flat block case used to calculate natural conservation has a customer charge of $28.93 in 2011 and it increases to $40.21 by 2015. Option 8.1 has a $28.93 customer charge that increases to $30.34 by 2013 and is frozen thereafter. Because of this, the energy charges go up more than average for Option 8.1. This results in additional savings from elasticity after 2011.

Both the flat block option and Option 66.3 have the same percent increases applied to the energy rates for 2012-2015. However, when that rate increase percent is applied to the lower rate in block 1 along with the lower elasticity numbers, the resulting long-term savings estimate is lower than in the case of the flat block. This means that while savings resulting from the original implementation are higher with an RIB than with a flat block, the additional long-term savings estimates that may occur in later years are lower with a RIB rate than with a flat rate.

7.2 Please resubmit the columns "**Cumulative Conservation** Impact from RIB" of Appendix B with the cumulative conservation impacts in both MWh and percentage.

<u>Response:</u>

Please see Table BCUC IR2 Q7.2 below.

Table BCUC IR2 Q7.2

					Cumulative Conservation Impact from RIB (%)					Cumulative Conservation Impact from RIB (MWh)				
	Base Rate Option	Threshold kWh	Rate Increase Applied	Elasticity Estimate	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
	Cont'd Flat Rate	1350	Pricing Principle 3 - All Components	.05/.10	0.0%	0.6%	1.3%	1.6%	2.5%	-	7,128	15,780	20,391	31,909
				.10/.20	0.0%	1.1%	2.5%	3.2%	4.9%	-	14,256	31,560	40,783	63,818
				.20/.30	0.0%	1.7%	3.8%	4.9%	7.6%	-	21,872	48,419	62,568	97,908
2.1	2	1350	Pricing Principle 1 - Both Blocks	.05/.10	1.9%	2.0%	2.1%	2.2%	2.4%	23,388	25,120	27,192	28,822	31,859
				.10/.20	3.7%	4.0%	4.2%	4.4%	4.9%	46,776	50,241	54,383	57,644	63,719
				.20/.30	5.5%	5.8%	6.2%	6.6%	7.2%	68,775	73,972	80,186	85,077	94,189
2.2	2	1350	Pricing Principle 2 - Block 2 Only	.05/.10	1.9%	2.5%	3.2%	3.6%	4.3%	23,388	32,304	41,304	46,482	55,681
				.10/.20	3.7%	5.1%	6.4%	7.2%	8.5%	46,776	64,608	82,609	92,965	111,362
				.20/.30	5.5%	7.5%	9.4%	10.5%	12.4%	68,775	94,873	121,117	136,171	162,811
4.1	4	2100	Pricing Principle 1 - Both Blocks	.05/.10	3.3%	3.4%	3.5%	3.6%	3.7%	41,871	43,169	44,700	46,080	48,390
				.10/.20	6.6%	6.8%	7.0%	7.1%	7.4%	83,742	86,338	89,399	92,159	96,780
				.20/.30	9.7%	10.0%	10.3%	10.5%	11.0%	122,372	126,866	132,186	136,714	144,615
4.2	4	2100	Pricing Principle 2 - Block 2 Only	.05/.10	3.3%	4.1%	4.9%	5.3%	5.9%	41,871	52,751	62,866	68,290	77,274
				.10/.20	6.6%	8.3%	9.8%	10.5%	11.8%	83,742	105,503	125,731	136,579	154,549
				.20/.30	9.7%	12.1%	14.3%	15.4%	17.2%	122,372	154,162	183,547	199,133	224,926

Table BCUC IR2 Q7.2 cont'd

					Cumulative Conservation Impact from RIB (%)					Cumulative Conservation Impact from RIB (MWh)				
	Base Rate Option	Threshold kWh	Rate Increase Applied	Elasticity Estimate	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
7.1	7	1600	Pricing Principle 1 - Both Blocks	.05/.10	3.0%	3.1%	3.2%	3.3%	3.5%	37,769	39,326	41,184	42,696	45,444
				.10/.20	6.0%	6.2%	6.4%	6.6%	6.9%	75,537	78,652	82,368	85,392	90,887
				.20/.30	8.8%	9.1%	9.5%	9.7%	10.3%	110,905	115,742	121,516	126,159	134,668
7.2	7	1600	Pricing Principle 2 - Block 2 Only	.05/.10	3.0%	3.7%	4.3%	4.7%	5.3%	37,769	46,634	55,444	60,457	69,219
				.10/.20	6.0%	7.3%	8.6%	9.3%	10.6%	75,537	93,268	110,888	120,914	138,438
				.20/.30	8.8%	10.8%	12.7%	13.6%	15.4%	110,905	136,795	162,414	176,915	202,190
8.1	8	1600	Pricing Principle 1 - Both Blocks	.05/.10	1.9%	2.0%	2.1%	2.2%	2.5%	23,591	25,349	27,442	29,136	32,217
				.10/.20	3.7%	4.0%	4.3%	4.5%	4.9%	47,182	50,698	54,885	58,272	64,433
				.20/.30	5.5%	5.9%	6.3%	6.7%	7.3%	69,274	74,712	81,192	86,380	95,888
8.2	8	1600	Pricing Principle 2 - Block 2 Only	.05/.10	1.9%	2.7%	3.5%	4.0%	4.7%	23,591	34,588	45,328	51,311	61,710
				.10/.20	3.7%	5.4%	7.1%	7.9%	9.4%	47,182	69,175	90,656	102,623	123,421
				.20/.30	5.5%	8.0%	10.4%	11.6%	13.8%	69,274	101,558	132,967	150,380	180,565
31	31	1500	Pricing Principle 1 - Both Blocks	.05/.10	3.1%	3.2%	3.3%	3.4%	3.6%	38,452	40,169	42,222	43,838	46,850
				.10/.20	6.1%	6.3%	6.6%	6.8%	7.2%	76,904	80,337	84,443	87,676	93,699
				.20/.30	9.0%	9.3%	9.7%	10.0%	10.6%	113,448	118,598	124,757	129,606	138,641
31	31	1500	Pricing Principle 2 - Block 2 Only	.05/.10	3.1%	3.7%	4.4%	4.7%	5.4%	38,454	47,205	56,052	61,151	70,213
				.10/.20	6.1%	7.4%	8.7%	9.4%	10.7%	76,908	94,411	112,104	122,301	140,426
				.20/.30	9.0%	10.9%	12.8%	13.9%	15.7%	113,454	139,058	164,842	179,656	205,889
11	11	1350	Pricing Principle 3 - All Components	.05/.10	1.8%	1.8%	1.8%	1.8%	1.8%	23,111	23,111	23,111	23,111	23,111
				.10/.20	3.7%	3.6%	3.6%	3.6%	3.5%	46,221	46,221	46,221	46,221	46,221
				.20/.30	5.4%	5.4%	5.3%	5.3%	5.2%	68,539	68,539	68,539	68,539	68,539

Table BCUC IR2 Q7.2 cont'd

					Cumulative Conservation Impact from RIB (%)					Cumulative Conservation Impact from RIB (MWh)				
	Base Rate Option	Threshold kWh	Rate Increase Applied	Elasticity Estimate	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
11	11	1350	Pricing Principle 4 - Customer and Block 2	.05/.10	1.8%	2.4%	3.0%	3.3%	3.9%	23,111	31,049	38,921	43,138	50,663
				.10/.20	3.7%	4.9%	6.1%	6.7%	7.7%	46,221	62,097	77,841	86,276	101,326
				.20/.30	5.4%	7.2%	8.9%	9.8%	11.3%	68,539	91,703	114,562	126,733	148,353
13	13	2100	Pricing Principle 3 - All Components	.05/.10	3.2%	3.1%	3.0%	3.0%	2.9%	40,051	39,451	38,723	38,335	37,365
				.10/.20	6.4%	6.2%	6.0%	5.9%	5.7%	80,103	78,903	77,446	76,670	74,731
				.20/.30	9.4%	9.2%	9.0%	8.8%	8.6%	118,067	116,867	115,411	114,634	112,695
13	13	2100	Pricing Principle 4 - Customer and Block 2	.05/.10	3.2%	3.9%	4.6%	4.9%	5.5%	40,051	50,163	59,399	64,022	71,668
				.10/.20	6.4%	7.9%	9.3%	9.9%	10.9%	80,103	100,327	118,798	128,044	143,335
				.20/.30	9.4%	11.6%	13.6%	14.5%	16.0%	118,067	147,553	174,302	187,484	209,260
16	16	1600	Pricing Principle 3 - All Components	.05/.10	2.9%	2.9%	2.8%	2.8%	2.7%	36,664	36,499	36,299	36,193	35,926
				.10/.20	5.8%	5.7%	5.7%	5.6%	5.5%	73,329	72,999	72,599	72,385	71,852
				.20/.30	8.6%	8.5%	8.4%	8.3%	8.2%	108,359	108,029	107,629	107,415	106,882
16	16	1600	Pricing Principle 4 - Customer and Block 2	.05/.10	2.9%	3.5%	4.1%	4.4%	4.9%	36,664	44,671	52,477	56,605	63,835
				.10/.20	5.8%	7.0%	8.2%	8.7%	9.8%	73,329	89,341	104,954	113,210	127,671
				.20/.30	8.6%	10.4%	12.0%	12.8%	14.3%	108,359	131,672	154,279	166,126	186,806
17	17	1600	Pricing Principle 3 - All Components	.05/.10	1.8%	1.8%	1.8%	1.7%	1.7%	22,948	22,784	22,583	22,477	22,210
				.10/.20	3.6%	3.6%	3.5%	3.5%	3.4%	45,897	45,567	45,167	44,954	44,421
				.20/.30	5.4%	5.3%	5.2%	5.2%	5.1%	68,083	67,753	67,353	67,140	66,607
17	17	1600	Pricing Principle 4 - Customer and Block 2	.05/.10	1.8%	2.6%	3.3%	3.7%	4.3%	22,948	32,941	42,553	47,576	56,336
				.10/.20	3.6%	5.2%	6.6%	7.3%	8.6%	45,897	65,882	85,107	95,151	112,672
				.20/.30	5.4%	7.7%	9.8%	10.8%	12.6%	68,083	97,356	125,381	139,910	165,180

Table BCUC IR2 Q7.2 cont'd

	Base Rate Option	Threshold kWh	Rate Increase Applied	Elasticity Estimate	Cumulative Conservation Impact from RIB (%) 2011	2012	2013	2014	2015	Cumulative Conservation Impact from RIB (MWh) 2011	2012	2013	2014	2015
32	32	1500	Pricing Principle 3 - All Components	.05/.10	2.8%	3.0%	3.0%	2.9%	2.9%	37,984	37,984	37,984	37,984	37,984
				.10/.20	5.6%	6.0%	5.9%	5.9%	5.8%	75,968	75,968	75,968	75,968	75,968
				.20/.30	8.2%	8.9%	8.8%	8.7%	8.6%	112,603	112,603	112,603	112,603	112,603
32	32	1500	Pricing Principle 4 - Customer and Block 2	.05/.10	2.8%	3.6%	4.2%	4.4%	5.0%	37,984	45,773	53,505	57,650	65,052
				.10/.20	5.6%	7.2%	8.3%	8.9%	9.9%	75,968	91,546	107,009	115,301	130,103
				.20/.30	8.2%	10.6%	12.3%	13.1%	14.6%	112,603	135,319	157,758	169,715	190,963
28	28	2100	Pricing Principle 1 - Both Blocks	.05/.10	2.6%	2.5%	2.5%	2.5%	2.5%	32,538	32,397	32,215	32,387	32,298
				.10/.20	5.2%	5.1%	5.0%	5.0%	4.9%	65,076	64,794	64,430	64,773	64,596
				.20/.30	7.6%	7.7%	7.7%	7.7%	7.7%	97,756	98,296	98,903	100,033	101,304
28	28	2100	Pricing Principle 2 - Block 2 Only	.05/.10	2.6%	3.3%	3.8%	4.1%	4.5%	32,538	41,540	49,398	53,307	59,314
				.10/.20	5.2%	6.5%	7.7%	8.2%	9.1%	65,076	83,080	98,796	106,614	118,629
				.20/.30	7.6%	9.7%	11.4%	12.1%	13.3%	97,756	123,792	146,289	157,211	173,951
28	28	2100	Pricing Principle 3 - All Components	.05/.10	2.6%	2.5%	2.4%	2.3%	2.1%	32,538	31,529	30,304	29,651	28,021
				.10/.20	5.2%	5.0%	4.7%	4.6%	4.3%	65,076	63,058	60,608	59,303	56,042
				.20/.30	7.6%	7.5%	7.3%	7.1%	6.8%	97,756	95,691	93,170	91,827	88,473
28	28	2100	Pricing Principle 4 - Customer and Block 2	.05/.10	2.6%	3.2%	3.7%	3.9%	4.3%	32,538	40,672	47,705	51,061	56,152
				.10/.20	5.2%	6.4%	7.4%	7.9%	8.6%	65,076	81,344	95,411	102,122	112,304
				.20/.30	7.6%	9.5%	11.0%	11.6%	12.6%	97,756	121,186	141,211	150,472	164,464
66	66	1350	Pricing Principle 1 - Both Blocks	.05/.10	2.5%	2.5%	2.5%	2.5%	2.5%	30,961	31,411	31,949	32,473	33,334
				.10/.20	4.9%	4.9%	5.0%	5.0%	5.1%	61,923	62,821	63,898	64,946	66,667
				.20/.30	7.6%	7.3%	7.4%	7.5%	7.6%	91,286	92,938	94,923	96,692	99,766

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Table BCUC IR2 Q7.2 cont'd

	Base Rate Option	Threshold kWh	Rate Increase Applied	Elasticity Estimate	Cumulative Conservation Impact from RIB (%) 2011	2012	2013	2014	2015	Cumulative Conservation Impact from RIB (MWh) 2011	2012	2013	2014	2015
66	66	1350	Pricing Principle 2 - Block 2 Only	.05/.10	2.5%	2.9%	3.4%	3.6%	4.1%	30,961	37,328	43,594	47,070	53,061
				.10/.20	4.9%	5.9%	6.8%	7.3%	8.1%	61,923	74,656	87,189	94,141	106,123
				.20/.30	7.6%	8.6%	9.9%	10.6%	11.8%	91,286	109,634	127,574	137,417	154,330
66	66	1350	Pricing Principle 3 - All Components	.05/.10	2.6%	2.4%	2.4%	2.3%	2.3%	30,961	30,657	30,287	30,090	29,598
				.10/.20	4.9%	4.8%	4.7%	4.6%	4.5%	61,923	61,314	60,574	60,180	59,196
				.20/.30	7.2%	7.1%	7.0%	6.9%	6.8%	91,286	90,676	89,937	89,543	88,559
66	66	1350	Pricing Principle 4 - Customer and Block 2	.05/.10	2.6%	2.9%	3.3%	3.5%	3.8%	30,961	36,574	42,032	44,921	49,883
				.10/.20	4.9%	5.8%	6.5%	6.9%	7.6%	61,923	73,149	84,065	89,843	99,767
				.20/.30	7.2%	8.4%	9.6%	10.1%	11.1%	91,286	107,372	122,888	130,970	144,796
69	69	1600	Pricing Principle 1 - Both Blocks	.05/.10	2.5%	2.5%	2.5%	2.5%	2.5%	31,381	31,632	31,928	32,336	32,879
				.10/.20	5.0%	5.0%	5.0%	5.0%	5.0%	62,762	63,264	63,856	64,671	65,757
				.20/.30	7.6%	7.4%	7.4%	7.5%	7.6%	92,535	93,835	95,388	96,966	99,482
69	69	1600	Pricing Principle 2 - Block 2 Only	.05/.10	2.5%	3.1%	3.6%	3.8%	4.3%	31,381	38,776	45,786	49,546	55,803
				.10/.20	5.0%	6.1%	7.1%	7.6%	8.5%	62,762	77,551	91,572	99,092	111,607
				.20/.30	7.6%	9.0%	10.4%	11.2%	12.4%	92,535	113,885	133,975	144,587	162,215
69	69	1600	Pricing Principle 3 - All Components	.05/.10	2.5%	2.4%	2.3%	2.3%	2.2%	31,381	30,833	30,167	29,813	28,927
				.10/.20	5.0%	4.9%	4.7%	4.6%	4.4%	62,762	61,666	60,335	59,626	57,854
				.20/.30	7.3%	7.2%	7.0%	6.9%	6.7%	92,535	91,438	90,107	89,398	87,626
69	69	1600	Pricing Principle 4 - Customer and Block 2	.05/.10	2.5%	3.0%	3.4%	3.7%	4.0%	31,381	37,977	44,163	47,339	52,592
				.10/.20	5.0%	6.0%	6.9%	7.3%	8.0%	62,762	75,953	88,325	94,678	105,185
				.20/.30	7.3%	8.8%	10.1%	10.6%	11.7%	92,535	111,488	129,105	137,966	152,583

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Table BCUC IR2 Q7.2 cont'd

	Base Rate Option	Threshold kWh	Rate Increase Applied	Elasticity Estimate	Cumulative Conservation Impact from RIB (%) 2011	2012	2013	2014	2015	Cumulative Conservation Impact from RIB (MWh) 2011	2012	2013	2014	2015
60	60	1350	Pricing Principle 1 - Both Blocks	.05/.10	2.5%	2.5%	2.5%	2.5%	2.5%	31,343	31,542	31,780	32,067	32,485
				.10/.20	5.0%	5.0%	5.0%	4.9%	5.0%	62,686	63,084	63,560	64,134	64,970
				.20/.30	7.4%	7.4%	7.4%	7.4%	7.5%	93,053	93,954	95,038	96,096	97,842
60	60	1350	Pricing Principle 2 - Block 2 Only	.05/.10	2.5%	3.0%	3.4%	3.7%	4.1%	31,343	37,850	44,215	47,683	53,659
				.10/.20	5.0%	6.0%	6.9%	7.4%	8.2%	62,686	75,699	88,430	95,367	107,318
				.20/.30	7.4%	8.8%	10.1%	10.8%	12.0%	93,053	111,820	130,057	139,878	156,745
60	60	1350	Pricing Principle 3 - All Components	.05/.10	2.5%	2.4%	2.4%	2.4%	2.3%	31,343	31,038	30,669	30,472	29,980
				.10/.20	5.0%	4.9%	4.8%	4.7%	4.6%	62,686	62,077	61,338	60,944	59,959
				.20/.30	7.4%	7.3%	7.1%	7.0%	6.9%	93,053	92,444	91,704	91,310	90,326
60	60	1350	Pricing Principle 4 - Customer and Block 2	.05/.10	2.5%	2.9%	3.4%	3.6%	3.9%	31,343	37,346	43,174	46,253	51,547
				.10/.20	5.0%	5.9%	6.7%	7.1%	7.9%	62,686	74,692	86,348	92,506	103,093
				.20/.30	7.4%	8.7%	9.9%	10.5%	11.5%	93,053	110,310	126,935	135,587	150,408
61	61	1350	Pricing Principle 1 - Both Blocks	.05/.10	1.7%	1.7%	1.7%	1.7%	1.7%	21,360	21,605	21,898	22,229	22,729
				.10/.20	3.4%	3.4%	3.4%	3.4%	3.5%	42,719	43,210	43,797	44,458	45,458
				.20/.30	5.1%	5.1%	5.2%	5.2%	5.3%	64,216	65,255	66,506	67,695	69,687
61	61	1350	Pricing Principle 2 - Block 2 Only	.05/.10	1.7%	2.3%	2.9%	3.2%	3.7%	21,360	29,324	37,042	41,197	48,355
				.10/.20	3.4%	4.6%	5.8%	6.4%	7.4%	42,719	58,648	74,084	82,394	96,709
				.20/.30	5.1%	6.9%	8.5%	9.4%	10.8%	64,216	87,356	109,652	121,532	141,944
61	61	1350	Pricing Principle 3 - All Components	.05/.10	1.7%	1.7%	1.6%	1.6%	1.5%	21,360	21,055	20,685	20,488	19,996
				.10/.20	3.4%	3.3%	3.2%	3.2%	3.1%	42,719	42,110	41,371	40,977	39,993
				.20/.30	5.1%	5.0%	4.9%	4.8%	4.7%	64,216	63,606	62,867	62,473	61,489

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Table BCUC IR2 Q7.2 cont'd

					Cumulative Conservation Impact from RIB (%)					Cumulative Conservation Impact from RIB (MWh)				
	Base Rate Option	Threshold kWh	Rate Increase Applied	Elasticity Estimate	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
61	61	1350	Pricing Principle 4 - Customer and Block 2	.05/.10	1.7%	2.3%	2.8%	3.1%	3.5%	21,360	28,774	35,919	39,665	46,115
				.10/.20	3.4%	4.5%	5.6%	6.1%	7.0%	42,719	57,548	71,838	79,330	92,230
				.20/.30	5.1%	6.7%	8.3%	9.0%	10.3%	64,216	85,707	106,283	116,936	135,226
63	63	1600	Pricing Principle 1 - Both Blocks	.05/.10	2.5%	2.5%	2.4%	2.4%	2.4%	31,424	31,412	31,393	31,552	31,633
				.10/.20	5.0%	4.9%	4.9%	4.9%	4.8%	62,848	62,823	62,785	63,104	63,265
				.20/.30	7.4%	7.4%	7.4%	7.4%	7.4%	93,443	93,953	94,562	95,395	96,522
63	63	1600	Pricing Principle 2 - Block 2 Only	.05/.10	2.5%	3.1%	3.6%	3.9%	4.3%	31,424	39,036	46,209	49,989	56,279
				.10/.20	5.0%	6.1%	7.2%	7.7%	8.6%	62,848	78,072	92,417	99,978	112,558
				.20/.30	7.4%	9.1%	10.6%	11.3%	12.6%	93,443	115,444	136,021	146,695	164,422
63	63	1600	Pricing Principle 3 - All Components	.05/.10	2.5%	2.4%	2.4%	2.3%	2.2%	31,424	30,876	30,210	29,856	28,970
				.10/.20	5.0%	4.9%	4.7%	4.6%	4.4%	62,848	61,752	60,421	59,712	57,940
				.20/.30	7.4%	7.3%	7.1%	7.0%	6.8%	93,443	92,346	91,015	90,306	88,534
63	63	1600	Pricing Principle 4 - Customer and Block 2	.05/.10	2.5%	3.0%	3.5%	3.7%	4.1%	31,424	38,500	45,123	48,516	54,140
				.10/.20	5.0%	6.1%	7.0%	7.5%	8.3%	62,848	77,000	90,246	97,031	108,280
				.20/.30	7.4%	9.0%	10.3%	11.0%	12.1%	93,443	113,837	132,765	142,275	158,004
19	19	1350	Pricing Principle 3 - All Components	.05/.10	2.7%	2.7%	2.7%	2.7%	2.6%	34,424	34,424	34,424	34,424	34,424
				.10/.20	5.5%	5.4%	5.4%	5.3%	5.3%	68,848	68,848	68,848	68,848	68,848
				.20/.30	8.2%	8.1%	8.0%	7.9%	7.9%	102,900	102,900	102,900	102,900	102,900
19	19	1350	Pricing Principle 4 - Customer and Block 2	.05/.10	2.7%	3.3%	3.9%	4.2%	4.7%	34,424	42,175	49,872	54,000	61,370
				.10/.20	5.5%	6.6%	7.8%	8.3%	9.4%	68,848	84,351	99,744	108,000	122,740
				.20/.30	8.2%	9.9%	11.5%	12.3%	13.8%	102,900	125,504	147,837	159,740	180,895

Table BCUC IR2 Q7.2 cont'd

	Base Rate Option	Threshold kWh	Rate Increase Applied	Elasticity Estimate	Cumulative Conservation Impact from RIB (%) 2011	2012	2013	2014	2015	Cumulative Conservation Impact from RIB (MWh) 2011	2012	2013	2014	2015
22	22	2100	Pricing Principle 3 - All Components	.05/.10	3.0%	2.9%	2.8%	2.7%	2.6%	37,282	36,682	35,954	35,566	34,596
				.10/.20	5.9%	5.8%	5.6%	5.5%	5.3%	74,565	73,365	71,908	71,132	69,193
				.20/.30	8.9%	8.7%	8.5%	8.4%	8.1%	111,889	110,688	109,232	108,456	106,516
22	22	2100	Pricing Principle 4 - Customer and Block 2	.05/.10	3.0%	3.9%	4.7%	5.1%	5.7%	37,282	49,550	60,588	66,040	75,055
				.10/.20	5.9%	7.8%	9.4%	10.2%	11.5%	74,565	99,101	121,176	132,081	150,110
				.20/.30	8.9%	11.6%	14.0%	15.1%	16.9%	111,889	147,842	179,997	195,668	221,551
25	25	1600	Pricing Principle 3 - All Components	.05/.10	2.8%	2.8%	2.7%	2.7%	2.6%	35,329	35,164	34,964	34,857	34,591
				.10/.20	5.6%	5.5%	5.4%	5.4%	5.3%	70,658	70,328	69,928	69,715	69,182
				.20/.30	8.4%	8.3%	8.2%	8.1%	8.0%	105,753	105,423	105,023	104,810	104,277
25	25	1600	Pricing Principle 4 - Customer and Block 2	.05/.10	2.8%	3.5%	4.2%	4.6%	5.2%	35,329	44,920	54,171	59,016	67,476
				.10/.20	5.6%	7.1%	8.4%	9.1%	10.3%	70,658	89,839	108,342	118,033	134,953
				.20/.30	8.4%	10.5%	12.5%	13.5%	15.2%	105,753	133,820	160,762	174,761	199,129
51	51	1350	Pricing Principle 1 - Both Blocks	.05/.10	2.7%	2.7%	2.7%	2.7%	2.6%	34,565	34,565	34,565	34,565	34,565
				.10/.20	5.5%	5.4%	5.4%	5.3%	5.3%	69,130	69,130	69,130	69,130	69,130
				.20/.30	8.2%	8.2%	8.1%	8.0%	7.9%	103,899	103,899	103,899	103,899	103,899
51	51	1350	Pricing Principle 2 - Block 2 Only	.05/.10	2.7%	3.4%	4.0%	4.3%	4.9%	34,565	42,972	51,282	55,722	63,632
				.10/.20	5.5%	6.8%	8.0%	8.6%	9.7%	69,130	85,944	102,565	111,444	127,265
				.20/.30	8.2%	10.1%	11.9%	12.8%	14.4%	103,899	128,471	152,645	165,483	188,259
54	54	2100	Pricing Principle 1 - Both Blocks	.05/.10	2.8%	2.8%	2.7%	2.6%	2.5%	35,848	35,248	34,520	34,132	33,162
				.10/.20	5.7%	5.5%	5.4%	5.3%	5.1%	71,697	70,497	69,040	68,264	66,325
				.20/.30	8.6%	8.5%	8.3%	8.1%	7.9%	108,720	107,520	106,063	105,287	103,348

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Table BCUC IR2 Q7.2 cont'd

					Cumulative Conservation Impact from RIB (%)					Cumulative Conservation Impact from RIB (MWh)				
	Base Rate Option	Threshold kWh	Rate Increase Applied	Elasticity Estimate	2011	2012	2013	2014	2015	2011	2012	2013	2014	2015
54	54	2100	Pricing Principle 2 - Block 2 Only	.05/.10	2.8%	3.9%	4.8%	5.2%	5.9%	35,848	49,328	61,349	67,243	76,977
				.10/.20	5.7%	7.8%	9.6%	10.4%	11.8%	71,697	98,657	122,698	134,486	153,955
				.20/.30	8.6%	11.7%	14.3%	15.5%	17.5%	108,720	148,309	183,413	200,410	228,451
57	57	1600	Pricing Principle 1 - Both Blocks	.05/.10	2.8%	2.7%	2.7%	2.7%	2.6%	34,855	34,690	34,490	34,383	34,117
				.10/.20	5.5%	5.5%	5.4%	5.3%	5.2%	69,710	69,380	68,980	68,767	68,234
				.20/.30	8.3%	8.2%	8.1%	8.0%	7.9%	105,064	104,735	104,334	104,121	103,588
57	57	1600	Pricing Principle 2 - Block 2 Only	.05/.10	2.8%	3.6%	4.3%	4.7%	5.3%	34,855	45,282	55,281	60,491	69,571
				.10/.20	5.5%	7.1%	8.6%	9.3%	10.6%	69,710	90,563	110,562	120,982	139,142
				.20/.30	8.3%	10.7%	12.8%	13.9%	15.7%	105,064	135,639	164,825	179,918	206,145

8.0 Reference: Exhibit B-11, Directive 2b, p. 9; Directive 5a, p. 19; Exhibit B-8

Elasticity and Conservation Measures

On page 9 of Exhibit B-11, FortisBC states: "despite annual rate increase in recent years, use per customer continues to rise. That is contradictory to the elasticity results when the calculations are applied to the projected annual rate increases for 2012-2015 under a continued flat rate design ... This finding leads us to further question the validity of relying on the calculated conservation savings for the RIB rate when selection the appropriate rate design."

On page 19 of the Additional Evidence, FortisBC states "price elasticity is generally believed to increase for any good as it becomes a greater percentage of disposable income."

8.1 Is FortisBC's long-term load forecast based on a time-series or end-use analysis?

Response:

FortisBC's long-term residential load forecast is based on a forecast of customer counts and normalized use per customer (UPC) which are multiplied together to arrive at the before DSM and Other Savings load forecast.

Customer counts are determined from a regression of the customer accounts on Provincial housing while UPC is taken to be the normalized average of the 2008 to 2010 UPC's.

8.1.1 Is FortisBC's long-term gross load forecast prepared on the basis of no real price increase? If not, what are the assumptions related to price increase over the forecast period?

Response:

No direct adjustment is made to the before DSM and Other Savings forecast to account for price increases. However, natural conservation from rate increases is part of the overall historical average use per customer trends and is therefore taken into consideration.

8.1.2 Please confirm that the price elasticities assumed in this Application are not derived from FortisBC's own data.

Response:

Confirmed.

8.2 FortisBC experienced rising use per customer in recent years despite annual rate increase, does this reflect factors such as growth in income, weather changes, and appliance saturation that could have overcome the price effect?

Response:

Analysis undertaken by the Company for the 2012 Load Forecast as presented in the 2012 Revenue Requirement Application in tab 3, page 5, states that the before DSM residential use per customer is assumed to remain constant from 2011 onward at 12.77 MWh, since there is no statistically valid evidence of either an upward or downward trend.

8.2.1 If rates had not increased annually but had remained constant, would the load increase be even sharper than what have occurred? Has FortisBC carried out any study to prove that price elasticity is contradictory to real experiences?

Response:

FortisBC has not carried out any specific studies on the price elasticity related to its annual rate increases. However, economic theory would agree with the assertion that the load increase would have been higher if rates had not increased annually.

9.0 Reference: Exhibit B-11, Directive 4a, p. 15; Directive 4b, p. 18

Long Run Marginal Cost (LRMC)

On p. 17, FortisBC states that "Using the projections contained in the Midgard Report, and a nominal discount rate of 8%, FortisBC has calculated a levelized value for its LRMC, for use in this Application, of $111.96 per MWh. Grossed up for losses at 11%, the value becomes $125.80 per MWh."

9.1 Please provide the calculation to arrive at a levelized LRMC value of $111.96 per MWh and also list the ‘new supply’ options it includes in the calculation.

Response:

The LRMC value of $111.96 was calculated from The BC New Resources Market Energy Curve presented in Table 5.2-A in the 2011 FortisBC Energy and Capacity Market Assessment, which is Appendix B of the FortisBC 2012 Long-Term Resource Plan.

As discussed in Section 5.2 of Appendix B, the BC New Resources Electricity Market Curve was based on the current BC Hydro Standing Offer Program average base price of $101.39/MWh in 2011 dollars, escalated at 50% CPI annually.

Please refer to BCUC Electronic Attachment 9.1 which shows the calculation for the levelized LRMC value of $111.96.

9.2 On page 6 of Appendix C in FortisBC’s 2012 Long Term DSM Plan, it is noted that “The third category is utility data which include current and forecasted loads, growth rates, avoided cost information, and line losses. FortisBC provided a load forecast by sector with average annual growth of 1.4 percent (gross load) over the planning period 2011 through 2030. Line losses are assumed at 8.8 percent over the period.” Please explain the 11% figure for lines losses used to gross up the LRMC and also reconcile that figure with the one used in the Long Term DSM Plan.

Response:

The Company chose to use the 11% loss figure as this is the value used for the residential class in the recently completed COSA and is closer to the approved primary-inclusive loss rate in FortisBCs tariff rate 109.

9.3 Please confirm the $125.80 per MWh does not include the cost of delivery.

Response:

The $111.96 levelized value is the estimated required contractual price to procure energy from a newly constructed BC generation resource, based on the BC Hydro Standing Offer Program prices. It is a plantgate price. It serves as a proxy for FortisBC’s LRMC from new resources.

The $125.80 includes the application of 11% losses, which was explained in BCUC IR2 Q9.2. There are no other delivery costs included, since it assumes any incremental transmission costs would be either paid directly by the project proponent or would be reflected in an adjustment to the plantgate price paid to the project.

9.4 Please elaborate on the concept of long run marginal cost (LRMC). Also explain the concepts of marginal incremental costs (MIC), average incremental cost (AIC), and long-run incremental cost (LRIC).

Response:

Please see the excerpt from the November 2004 report, *Estimation of Long Run Marginal Cost (LRMC)*, prepared by Marsden Jacob Associates for the Queensland Competition Authority, attached to these responses as Appendix BCUC IR2 9.4.

9.5 Please explain how BC Hydro calculates its modified LRMC as a basis for the Step-2 rate and how this modified LRMC differs from the concept of LRMC.

Response:

According to Commission Order G-45-11, page 8,

> "*BC Hydro's conservation rates, including the residential Step-2 rate, have consistently used the levelized weighted-average plant-gate price of BC Hydro's most recent call for energy as a proxy for its LRMC for rate setting purposes. The BC Hydro RIB rate, first approved for an effective date of October 1, 2008, with a Step-2 rate based on the estimated cost of new energy supply at the plant gate, grossed up for losses, of 8.27 ¢/kWh, and phased in over a six month period. This specific rate was based on the F2006 Call for Tenders. BC Hydro states that based on its 2009 CPC the Step-2 energy rate could be increased to as high as 13.2 ¢/kWh on April 1, 2011*".

FortisBC is unclear on what the question means when it refers to a "modified LRMC" and how this modified LRMC differs from the concept of LRMC, as Commission Order G-45-11 makes no specific reference to a modified LRMC.

As discussed in the BCUC order above, BC Hydro's proxy for LRMC is the levelized weighted-average firm plantgate energy price. BC Hydro levelizes its price using a methodology that assumes annual escalation at the rate of inflation.

Based on Appendix B Section 4 of Exhibit B-1, FortisBC has assumed the "modified LRMC" refers to an adjustment for inflation assumptions, and transmission and distribution line losses for delivery to the residential customer.

9.6 Please calculate FortisBC's LRMC segmented by the energy cost including line loss, transmission delivery cost, and distribution delivery cost. State the assumptions and show the calculations.

<u>Response:</u>

As shown in BCUC IR2 Q9.2, the proxy for the FortisBC LRMC for new resources was developed from the BC New Resources Energy Market Curve. The resulting levelized LRMC of $111.96 is a plantgate price. As discussed in BCOAPO IR2 Q12e, this LRMC is at the plantgate and has been levelized as a flat, unescalated price in nominal dollars over the 30 year forecast period starting in 2011. It is assumed any incremental transmission needed related to the project would be paid by the project proponent or would result in an adjustment to the price paid. Therefore the only incremental cost for delivery to the customer would be adjusting for losses of 11%. Adjusting for transmission and distribution losses is consistent with the approach utilized by BC Hydro for its RIB rate.

The application of 11% line losses utilizes the formula:

$111.96/(1.00-.11)=$125.80.

9.7 What is the estimated annual rate of increase for FortisBC's long run marginal cost of electricity for the period 2012-2015?

<u>Response:</u>

As illustrated in BCOAPO IR2 Q12f, the $111.96 levelized LRMC of new resources has been levelized as a flat unescalated price in nominal dollars over the 30 year forecast period starting in 2011. Using this levelized LRMC as a starting point, there would be no annual rate of increased from 2012 – 2015.

9.7.1 In its recent RIB Rate Re-Pricing Application, BC Hydro escalated its 2012 LRMC by inflation and lines losses. Would FortisBC find this method desirable? If not, please provide FortisBC's method of escalation and provide the results in tabular form.

Response:

FortisBC believes that the methodology for applying RIB rates provided in its application is appropriate and "desirable". As discussed in 4(b) of Exhibit B-11, with the FortisBC's LRMC for new resources at $125.80, it is very close to the Block 2 rate that would be in effect within a small number of years regardless of the starting rate selected, so capping Block 2 at the LRMC of new resources may not provide a proper conservation signal".

The FortisBC LRMC for BC New Resources Market Energy provided in Table 4b of the Additional Evidence Filing (Exhibit B11) is levelized to provide a flat dollar amount. There is no escalation for the period 30 year they were based on. The LRMC would have to be recalculated to provide a lower starting point if it were to be escalated.

As requested, the following table provides the escalation results for 2012-2015 in tabular form.

Table BCUC Q9.7.1

Year	$/MWh (Nominal dollars, no losses)	Rate of Increase
2011	$111.96	0%
2012	$111.96	0%
2013	$111.96	0%
2014	$111.96	0%
2015	$111.96	0%

9.8 The delivered LRMC is theoretically the cost of the last incremental units generated, resulting in the LRMC revenue to be a small portion of the total revenue. The Block 2 rate is proposed to be charged not only for the last incremental units but for all consumption above the threshold. This would result in the LRMC revenue to be a more sizable portion of the total revenue. Given that situation, what would be an appropriate Block 2 rate to apply to all consumption above the threshold (i.e., more than the last units consumed) that also sends an appropriate and efficient price signal to customers to conserve.

Response:

The Company has previously stated in response to BCUC IR1 Q9.7 that, *Section 3.2 of the Application states that the "RIB rate allows the utility to introduce price signals that reflect the increased marginal cost of electricity." In other words, the RIB rate provides a mechanism to charge higher prices for power as consumption increases. An efficient price signal provides an incentive for a customer to either lower consumption or refrain from increasing consumption. In order to do this, the differential between the block 1 and block 2 rates must be sufficient to affect customer behaviour. A price signal can be efficient at incenting conservation whether or not it reflects the marginal cost of electricity.*

In the opinion of the Company, a block 2 rate that is higher than the block 1 rate will provide a conservation incentive. Even if the LRMC is not used as a referent for the block 2 rate, FortisBC considers that a RIB rate can send an appropriate and efficient price signal to customers to conserve.

RIB Pricing Scenarios

9.9 What would the Block 1 rate be if the Block 2 rate was set at $0.12580 per kWh, the Customer Charge was set at $28.93 per billing period, the threshold was set at 1,600 kWh and the Block 1 rate was calculated residually to ensure revenue neutrality?

<u>Response:</u>

The responses to BCUC IR2 Q9.9, Q9.9.1, Q9.9.2, and Q9.9.3 are contained in the table below.

Table BCUC IR2 Q9.9

Threshold	1200	1350	1500	1600
Customer Charge	$28.93	$28.93	$28.93	$28.93
Block 1 Rate	$.05881	$.06424	$.06840	$.07072
Block 2 Rate	$.12580	$.12580	$.12580	$.12580
Rate Differential	113.9%	95.8%	83.9%	77.9%
Share of Revenue from Block 2	57%	52%	47%	44%

Note that the option with a threshold of 1600 kWh is very similar to Option 7 in the application. In all cases the block 2 rate results in a 38% increase from the equivalent flat block rate. The block 1 rate is decreased from the flat block rate by a range of 22% to 35%.

9.9.1 Please re-calculate the Block 1 rate with thresholds of 1,200, 1,350 and 1,500 kWh per billing period.

Response:

Please see the response to BCUC IR2 Q9.9 above.

9.9.2 For each the four threshold levels please provide the share of the revenue generated by the Block 2 rate in relation to the whole revenue for the residential rate class.

Response:

Please see the response to BCUC IR2 Q9.9 above.

9.9.3 For a 100 kWh downward change from 1600 kWh in the threshold, please elaborate on how it would affect Block 1 (new rate, rate difference, percentage change) given Block 2 is unchanged at $0.1258 per kWh and the Customer Charge remains unchanged at $28.93.

Response:

When the threshold is reduced by 100 kWh, from 1600 kWh to 1500 kWh per billing period, the block 1 rate is reduced from $.07072 to $.06840. This is a difference of $.0119 or 3.3 percent.

9.9.4 What is the optimal Block 2 percentage of residential revenue that would send a good conservation signal to the customer? Please provide a justification.

Response:

FortisBC does not believe that there is a single optimal Block 2 percentage of residential revenue that would send a good conservation signal to the customer. In designing rates, it is the goal of FortisBC to balance the various goals as provided in the application (Exhibit B-1, page 9 and page 23) and consider conservation signals in addition to other issues such as rate stability, customer impacts and customer acceptance. It is expected that any number of RIB rate designs could meet the goals laid out by FortisBC, including sending good conservation signals, and that a numerical formula cannot provide one single optimal rate design. The various analyses are a tool to measure whether the rate design meets the objective of the utility and they must be used along with experience and judgment in selecting an appropriate rate design. Given the various goals and analysis completed, FortisBC has proposed that Option 8 is its preferred rate design.

9.10 What would the Block 1 rate be if the Block 2 rate was set at the estimated **delivered** LRMC (calculated in question 9.3 above), the Customer Charge was at $28.93 per billing period, the threshold was set at 1,600 kWh and the Block 1 was calculated residually to ensure revenue neutrality? In this case, please assume the delivered LRMC to the residential customer is the delivered long-run cost of power from "new" projects (not currently existing), which excludes purchases from the market and BC Hydro.

Response:

Question 9.3 above does not contain a request for the calculation of the delivered LRMC. However, as explained in the response to BCUC IR2 Q9.6, the only adjustment to the plantgate price in consideration of additional delivery costs is for losses. The block 1 and block 2 rates that result from the parameters contained in this question, and using the LRMC of $125.80 as derived in the response to BCUC IR2 Q9.6 can be found in the table in response to BCUC IR2 Q9.9 above.

9.11 Please elaborate on the benefits and challenges of setting the Block 2 rate at the delivered LRMC of new supply.

Response:

As shown in BCUC IR2 Q9.6, the proxy for the FortisBC LRMC for new resources was developed from the BC New Resources Energy Market Curve, with the only incremental cost for delivery to the customer being an adjustment for losses. This value is $125.80 / MWh.

Depending upon the other attributes of the particular RIB rate, there are a number of options contained in Exhibit 10-1 that have a block 2 rate similar to this LRMC figure. Benefits in terms of conservation impact would be expected to be similar to those options.

There is no particular challenge in setting the block 2 rate at this level versus any of the other levels presented in the Application of subsequent materials, provided that one of the pricing principles is applied as described in Table 8-3 of Exhibit B-1.

The challenge lies in using the LRMC as a cap for the block 2 rate given that in the majority of rate options that cap would be reached quickly.

9.11.1 Please provide the pros and cons of phasing-in a Block 2 rate set at the delivered LRMC in order to mitigate unfavourable annual customer bill impacts. Please elaborate on how the phasing-in can be done. Please explore options for a 2-year and 3-year phase-in period for a Block 2 rate set at the LRMC.

Response:

In filing Exhibit B-11, FortisBC provided additional evidence regarding the appropriate LRMC , based upon the procurement of BC New Resources Market Energy. This value is $125.80 /MWh.

With respect to phasing-in the RIB rate, the Company notes:

- A phase-in is not preferred using the RIB rate determination presented in the Application as the setting of the block 2 is accomplished by formula. Setting the block 2 rate at any level other than that arrived at in the manner contemplated in the Application will violate the Customer Impact criterion.
- With reference to Appendix B of Exhibit 11, the “Reasonable Options”, it is noted that the block 2 rate would exceed the LRMC in all options by 2013 and all except 5 options in 2012.

Given the level of the LRMC relative to the block 2 rates that appear in the regulatory record, the Company is of the opinion that the phase-in of the RIB rate could be accomplished by setting the initial rate parameters as described in the Application and applying the appropriate pricing principle.

If the LRMC is also chosen as a “cap” for the block 2 rate, then after this cap is reached, future increases will need to be applied to the Customer Charge or block 1 rate. This will quickly lead to the re-establishment of a flat rate.

Customer Charge Scenarios

9.12 Suppose the Customer Charge is set at $28.93 per two-month billing period, the Block 2 rate is set at the estimated delivered LRMC of new power, the threshold at 1,600 kWh, and the Block 1 rate is calculated residually to ensure revenue neutrality. Hypothetically and for illustrative purposes, if the Customer Charge were changed to zero, then the Block 1 rate and/or the Block 2 rate would need to rise for the total revenue to remain unchanged.

9.12.1 If only the Block 2 rate were to rise, thus reaching a rate above the utility's LRMC, what would be the implications to the utility (benefits and challenges)?

Response:

If, after the rate was initially set such that the block 2 rate equalled LRMC, the Customer Charge were set at $28.93, and the threshold was 1600 kWh, the Customer Charge was reduced to zero and the block 1 rate held static, the block 2 rate would rise as in the following table. Both of these rates are equivalent in terms of revenue to the rates in Table 7-2 of the Application and are assumed to both occur at the same point in time.

	Initial	Hypothetical
Customer Charge	$ 28.93	$0.00
Block 1 Rate	0.07072	0.07072
Block 2 Rate*	0.1258	0.1629

* LRMC per table 4b in Exhibit B-11

Implications for the utility are two-fold. First, as discussed in the Additional Evidence Exhibit B-11, a Customer Charge of zero introduces an undesirable amount of revenue instability to the utility.

Second, the level of the resulting block 2 rate is high enough that the utility-customer relationship could be damaged as high-consumption customers would be disproportionately affected.

9.12.1.1 Would the utility find this pricing method desirable? Please explain.

Response:

The utility would not find this rate desirable for the reasons given in the response to BCUC IR2 Q9.12.1.

- The absence of a Customer Charge introduces revenue instability and does not reflect the principles of cost causation.

- The block 2 rate is too high relative to the block 1 rate and would unduly harm high consumption customers.

9.12.2 If only the Block 1 rate were to rise, what are the implications to the utility (benefits and challenges)?

Response:

If, after the rate was initially set such that the block 2 rate equalled LRMC, the Customer Charge were set at $28.93, and the threshold was 1600 kWh, the Customer Charge was reduced to zero and the block 2 rate held static, the block 1 rate would rise as in the following table. Both of these rates are equivalent in terms of revenue to the rates in Table 7-2 of the Application and are assumed to both occur at the same point in time.

	Initial	Hypothetical
Customer Charge	$ 28.93	$0.00
Block 1 Rate	0.07072	0.09218
Block 2 Rate*	0.1258	0.1258

* LRMC per table 4b in Exhibit B-11

Implications for the utility are two-fold. First, as discussed in the Additional Evidence Exhibit B-11, a Customer Charge of zero introduces an undesirable amount of revenue instability to the utility.

Second, the resulting increase in the block 1 rate is in excess of 30%. Although somewhat mitigated by the elimination of the Customer Charge, customer perception is likely to be negative.

No immediate benefit to the utility is evident.

9.12.2.1 The above scenario would narrow the difference between the Block 1 rate and the Block 2 rate. What conservation signal does the narrowing between the blocks sends to customers and what would the impact be on energy conservation?

Response:

In the opinion of the Company, the differential between the block 1 and block 2 rate is a significant determinant in the conservation potential of the RIB rate. The block differential becomes smaller when the hypothetical change is made and based on the assumptions presented, will decrease the conservation signal. In addition, if the block 2 rate is capped at the LRMC, the differential will decrease with subsequent rate increases, further reducing the conservation impact of the rate.

9.12.2.2 Would the utility find this pricing method desirable? Please explain.

Response:

The Company does not find this pricing method desirable. FortisBC does not believe that eliminating the Customer Charge is prudent, nor is it instituting a rate that reduces the conservation impact over time.

In determining the various rate options presented in the Application and other materials to date, customer impact is a primary consideration. Simply setting any of the rate components at a given level essentially discards this aspect of the design.

9.12.3 Please elaborate on how the elimination of the Customer Charge may impact the number of customer connections and the overall cost to the utility given it no longer recovers the COSA amount through the Customer Charge.

Response:

The Company does not anticipate that eliminating the Customer Charge, by itself, will materially impact the number of customer connections or the cost to the utility. There could be some additional incentive for customers to have multiple meters and thereby shelter more of their load in the lower block, if there were no Customer Charge. Multiple meters would increase “customer connections” and add to the cost of service for the utility.

10.0 Reference: Exhibit B-1, Section 2.5 Legislative and Regulatory Framework, p. 7

RIB Effects on Conservation and GHG reductions

"Policy Action #4 - Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation."

10.1 A RIB rate structure is meant to send a price signal to customers that would encourage them to conserve energy.

10.1.1 If an existing customer premise changed to two meters instead of one meter under the scenario of a Customer Charge of $0.00 with no impact on energy consumption, what would be the impact to revenues for that customer class in the proposed RIB rate structure?

Response:

Under the proposed RIB rate structure, the installation of an additional meter to serve the same load could, depending on the level of that load, lead to a reduction in revenue. This situation results from a doubling of the amount of energy that could be billed at the block 1 rate. Consumption that would be billed at the block 2 rate with a single meter would be billed at the lower block 1 rate.

10.1.2 A single dwelling with 6 people in the household would generally use less energy per capita than three dwellings with the same people spread over three households given similar lifestyles. How does the proposed RIB rate structure encourage per capita energy conservation?

Response:

A RIB rate structure does not explicitly encourage "per capita energy conservation". The energy conservation that is expected to occur is based on the economic theory of the price elasticity of demand. Although only the person(s) responsible for paying the bills in a household are directly exposed to the RIB price signal that creates the reduced demand, all members in a household are expected to be impacted by the decisions made by the person(s) paying the bills.

10.1.3 How does the proposed RIB rate structure affect a customer who uses natural gas as the primary space-heating energy source as opposed to a customer who uses electricity as the primary space-heating energy source?

Response:

All else being equal, a natural gas-heated customer will spend less on electricity than an electrically-heated customer. This would make the natural gas-heated customer less price-responsive to the proposed RIB rate structure than the electrically-heated customer since the cost of electricity would form a smaller portion of their budget.

10.1.3.1 Would these two types of customers react differently to the proposed RIB rate structure?

Response:

Please see the response to BCUC IR2 Q10.1.3.

10.1.3.2 When changing from a flat rate structure to a RIB rate structure, which customer type would see greater benefits?

Response:

Depending on their total level of consumption, neither customer type may see "benefits" as measured by a lower total cost of electricity. However, all else being equal, a natural gas-heated customer will see a lower increase (or bigger decrease) than an electrically-heated customer.

10.1.3.3 Does the utility know which customers are space-heating load customers and which are non-space heating load customers?

Response:

FortisBC does not have information regarding the specific heating source for the majority of individual customers.

10.1.3.4 Has the utility considered having separate rates for space-heating customers and non-space-heating customers? What are the benefits and challenges to this separation of rate classes?

Response:

FortisBC has not applied for separate rates based on space-heating type. This is due to three primary factors:

1. the principle of postage-stamp rates within a customer class
2. the fact that many customers have limited choice in the heating source they use
3. the administrative cost associated with obtaining the fuel source information initially, and the updating and auditing of that information subsequently

10.2 If the Block 2 rate were set at a level substantially above the LRMC, is it possible that some existing customers (through home renovations) or future customers (through new construction) may opt to use a less expensive alternative energy source that emits GHG thus defeating the intent to conserve electricity and reduce GHG emissions? Please elaborate.

Response:

Any Block 2 rate that is higher than the current flat rate, regardless of whether it is above the LRMC, may encourage customers to opt for less expensive alternative energy sources. If these alternative energy sources emitted GHGs, then the RIB rate may achieve the goal of conserving electricity while failing to reduce GHG emissions.

10.3 Compared to the existing rate structure, does the utility's proposed RIB rate structure increase or decrease GHG emissions in the long-run given the anticipated aggregate customer reaction to energy pricing and alternative energy options for new and existing customers. Please explain.

Response:

FortisBC has not modeled possible fuel-switching to alternative energy sources. The most likely response from electrically-heated customers wishing to reduce their heating costs (which are generally the largest portion of a residential bill) are 1) they will turn down their thermostats, 2) they will purchase a more efficient electric heating system such as a heat pump or 3) that they will purchase a non-electric heating system.

It is difficult to predict which of these options customers will choose (if any). Fuel choice availability, future prices and government regulations will all have an impact.

10.3.1 Please elaborate on how different changes respectively to the Customer Charge, threshold, Block 1 rate and Block 2 rate may impact favourably or unfavourably on GHG emission reductions.

Response:

All else being equal, changes that increase the cost of electricity for electrically-heated customers will are likely to increase fuel-switching to alternative heating sources. To the extent that these choices are GHG-emitting, then this would unfavourably impact GHG emission reduction goals.

Generally speaking, reductions in the Customer Charge and block threshold, and increases to the Block 2 rate, would be most likely to increase the cost of electricity for electrically-heated customers.

11.0 Reference: Exhibit B-11, Directive 4a, p. 15; Directive 4b, p. 18; Exhibit B-5, BCUC IR 4.1;

Review of BC Hydro, June 2011, pp. 84-85

Rate Design Objectives

On p. 15, FortisBC states that its primary consideration in the rate design was the limitation of customer impact. It believes that customer impacts are the more determinative factor in choosing a rate option.

On p. 18, FortisBC quotes from the June 2011 Review of BC Hydro where on pages 84 and 85, the Review Report describes the possibility that a rate structure designed to achieve one objective can impact attaining another objective; and recommends that the province clarify the objectives and priorities and/or relative ranking among competing objectives of the rate structure design.

11.1 If the province provides clarifications and directions to BC Hydro regarding priorities or relative ranking, what is FortisBC's view with respect to aligning with BC Hydro's ranking of objectives in rate design?

Response:

The Company would react to any emerging governmental policy depending on the context in which it was delivered. Were the release of such clarification and direction directed only at BC Hydro, then the Company would assess the potential impact to FortisBC and its customers prior to arriving at a course of action. The Company generally wishes to support the energy conservation objectives of the Province, but must consider customer impact in balance with other priorities.

Clarification of directives that carries the weight of statute or regulation will of course receive the appropriate compliance.

11.2 Please describe the decision making process which leads FortisBC to choose customer impacts as its primary consideration in the implementation of RIB rate.

Response:

The attention by the Company to customer impact is a consistent consideration with any decision that will affect customer rates.

Aside from the collection of the revenue requirement, the Company recognizes that any decision on the design of a new rate will involve a balancing of competing objectives.

In the case of the RIB rate, the importance placed upon the customer impact was less the result of a process than a general policy position of the Company.

In BCUC IR 4.1, FortisBC states that "Provincial consistency in this context refers to implementing a rate similar, though not necessarily identical, to that of BC Hydro."

11.3 Please elaborate on FortisBC's objective to maintain "provincial consistency" with the current BC Hydro RIB Rate in light of the Government Panel's recommendation to clarify the objectives and priorities of the rate structure design, which may result in a modification to the current BC Hydro RIB Rate.

Response:

FortisBC adopted an approach to the design of its RIB rate such that it would mirror the structural elements of the BC Hydro RIB rate. This was seen by the Company as reasonable given that this basic structure had already been tested and approved by a regulatory process in the province.

Should a modification to the structure of the BC Hydro RIB rate result from the Government Panel review, the Company will assess the impact to its own rate design. The objective to maintain Provincial consistency remains in place and changes to the FortisBC rate would likely follow provided that impact to customers is not negative.

11.3.1 Does FortisBC give more importance to the objective of "provincial consistency" than to designing a residential rate structure that would suit the particular conditions of FortisBC's service territory?

Response:

Provincial consistency is a precept predicated upon the external mandate upon the Company to implement a RIB rate.

Without such a mandate, the Company would evaluate any potential conservation rate in consideration of the specific needs of FortisBC and its customers.

12.0 Reference: Exhibit B-11, Directive 7, p. 26; Exhibit B-1, Section 6, Methodology, p. 19

Exhibit B-5, BCUC IR 17.1

Sample of Residential Customers

In the response to the Directive 7, FortisBC states that "The sample of 871 direct residential customers taken from the survey for use in the bill impact analysis reflects a 6.6 margin of error at the 95% confidence level. We believe this data is representative of the entire residential class. The percent of customer in each usage category reflects all customers on the system and therefore fully represents the entire class."

FortisBC also states on p. 19 of the Application that "To ensure that the sample data represented the customers proportionally, an additional sampling of large usage residential customers was added and the sample was increased to 906 customers."

In BCUC 17.1, FortisBC states that "The sample of 906 customers was used, including the added large-usage customers, so that the impacts across all categories would be shown in the analysis."

12.1 Please clarify again which representative sample of customers FortisBC used to evaluate the impact of a rate option on customer bills – the sample of 871 customers or the sample of 906 customers?

Response:

The sample of 906 customers was used to evaluate the bill impacts.

13.0 Reference: Exhibit B-11, Directive 8, pp. 27-28

COSA-Based Customer Charge

FortisBC states on p. 28 that "The results showed a customer-related cost of $12.95 for a 2-month period for 2009. This reflects a scenario where only those costs associated with metering, customer service, accounts and sales and a lower pro-rated share of general plant and A&G were included."

13.1 How does this amount of $12.95 compare with the sum of $13.62 in the Table on p. 27 ($5.88 for costs of the meter, service and meter reading plus $7.74 for per customer costs of accounting, billing and customer service)?

Response:

The $12.95 is made up of $5.99 for meters, etc. plus $6.96 for customer accounting, etc.

13.1.1 Please explain the difference between the two amounts. Why the $13.62 does not reflect the minimal costs associated with connecting a customer?

Response:

The $13.62 was based on the Compliance COSA dated November 19, 2010, which differs from the original COSA dated September 25, 2009 used to develop the $12.95 value. The $13.62 is based on a breakout of the costs into various components while the $12.95 value was based on removing certain costs from being included in the sum. With those costs removed, it had an impact on the pro-rated amount of general plant and A&G that was included in the value.

14.0 Reference: Exhibit B-6, BCOAPO IR 3b & 3d

BC Hydro Flow Through

FortisBC states in BCOAPO 3b that "The table has been updated with the assumed BC Hydro rate increase of 8.0 per cent per annum in each year. The Company has calculated the impact of the increase in 2011 to be a 0.9 per cent annualized increase."

However, in BCOAPO 3d, FortisBC states that "In general, a one per cent increase in BC Hydro's rates for a calendar year will result in an approximate 0.2 per cent rate increase to FortisBC's residential customer rates for the same period."

14.1 According to the last statement, an 8 per cent increase in BC Hydro's rate should result in a 1.6 per cent increase in FortisBC's rates, which is different than the 0.9 per cent noted in the first statement. Please reconcile the difference and confirm which statement is accurate.

Response:

FortisBC confirms that both statements are accurate, the difference being the result of the assumed timing of the BC Hydro rate increases. The response provided to BCOAPO IR1 Q3d assumes that a one percent increase to BC Hydro's rates is effective January through December of a given calendar year. This results in an approximate 0.2 percent rate increase (0.16 percent) to FortisBC customers to recover the increased BC Hydro power purchase costs for an entire calendar year.

The 0.9 percent increase referenced in the response to BCOAPO IR1 Q3b is based on the assumption that BC Hydro's rate adjustments are made effective April 1 of the calendar year (consistent with the provincial government's fiscal year). The 0.9 percent increase to FortisBC customers represents the increased power purchase expense to be collected from ratepayers over the remaining nine months of the calendar year, with the impact of the increased BC Hydro power purchase expense for the first three months of the following calendar year captured as a component of FortisBC's general annual rate adjustment, effective January 1 of that following year.

Assuming instead that a one percent increase to BC Hydro rates is effective April 1 of a given year, the resulting impact to FortisBC customers for the remaining nine months of the year becomes approximately 0.11 percent, which is consistent with the response previously provided to BCOAPO IR1 Q3b.

15.0 Reference: Exhibit B-6, BCOAPO IR 13c; Exhibit B-1, Table 7-2

Uniform Price Elasticity

15.1 Table BCOAPO IR1 Q13c displays negative numbers for the conservation impact of options 1 to 9 assuming uniform price elasticity for both blocks while Table 7-2 of the Application displays positive numbers. Does this mean that energy consumption increases when using the assumption that the price elasticity is the same for both blocks? If not, please clarify.

Response:

Energy consumption will increase when the price elasticity is the assumed to be the same for both blocks compared to the case when a higher elasticity number is used for Block 2. Because the Block 1 rate actually decreases compared to the flat block rate, it is expected that the consumption facing block 1 will actually increase. This increase is offset by the decline in consumption for block 2, where the rate is higher than the flat block rate. Under the savings figures provided in the Application, the block 2 elasticity is greater than the block 1 elasticity. If the block 2 elasticity is reduced to the same level as the block 1 value, the savings associated with block 2 will be less.

15.2 Please re-submit Table BCOAPO IR1 Q13c with the conservation impact in MWh in addition to percentages.

Response:

The following provides the requested MWh savings associated with the RIB rate when the elasticity estimates are set at the same level. Note that in the case of BCOAPO IR1 Q13c the negative conservation impact numbers in the response represent a reduction in consumption. In other words, a negative impact on usage translates into a positive savings number. For clarity, the table below represents conservation savings associated with the 9 RIB Rate Options.

Table BCUC IR2 Q15.2

	Conservation Savings (%) (-lower/upper)			Conservation Savings (MWh) (-lower/upper)		
Option	.05/.05	.10/.10	.20/.20	.05/.05	.10/.10	.20/.20
1	1.3%	2.7%	5.3%	16,749	33,498	66,996
2	0.9%	1.7%	3.5%	10,999	21,999	43,998
3	0.4%	0.8%	1.6%	5,095	10,189	20,378
4	1.5%	3.1%	6.1%	19,315	38,630	77,260
5	0.9%	1.7%	3.4%	10,727	21,455	42,910
6	0.3%	0.6%	1.3%	4,094	8,189	16,377
7	1.4%	2.8%	5.6%	17,684	35,367	70,735
8	0.9%	1.8%	3.5%	11,046	22,091	44,182
9	0.4%	0.7%	1.5%	4,665	9,330	18,660

16.0 Reference: Exhibit B-6, BCSEA IR 4.1; Exhibit B-6, BCOAPO IR 20d

Characteristics of High-Usage Customers

Table BCSEA IR1 Q4.1

	Consumption (kWh)	Mean Annual Consumption (kWh)	Percentage of Consumption	Percentage of Customers	Bill Impact
Low	< 6,000	3,573	9%	29%	-9%
Medium	6,000 - 18,000	10,811	50%	54%	-5%
High	> 18,000	29,002	41%	16%	+10%

FortisBC does not have readily available data that would identify common characteristics of these consumption groups, although it expects that building size and fuel choice are the biggest determinants of consumption. Even fuel choice is not particularly determinative however, as the average annual consumption for electric heat customer is 13,422 kWh and the average for non-electric heat is 9,708 kWh.

Table BCOAPO IR1 Q20d

	< $20,000	$20,000-$40,000	$40,000-$60,000	$60,000-$80,000	$80,000-$120,000	> $120,000
Mean kWh	1,470	1,712	1,786	2,101	2,173	2,329
Median kWh	968	1,471	1,496	1,869	1,798	1,601

16.1 For the high-usage customers consuming more than 18,000 kWh annually, please provide the breakdown of customers (number and percentage) for each of the income bracket in Table 9-1 of the Application.

Response:

The following shows the breakdown of customers (number and percent) for customers with annual usage over 18,000 kWh per year. Also shown is the breakdown for customers with all usage levels. Note that this is for the survey sample of customers. This information is not available for all customers on the system.

Table BCUC IR2 Q16.1

	Over 18,000 kWh per year	Customers at all usage levels
Income <$20k	3 2.7%	51 6.7%
Income $20k-$40k	24 21.2%	213 27.8%
Income $40k-$60k	18 15.9%	182 23.8%
Income $60k-$80k	30 26.5%	137 17.9%
Income $80k-$120k	22 19.5%	127 16.6%
Income >$120k	16 14.2%	56 7.3%

16.1.1 In case FortisBC does not have information readily available to answer the previous question, does FortisBC agree that it would be impossible that a high-usage customer (i.e., > 18,000 kWh annual consumption and a mean annual consumption of 29,002 kWh) would fall in the low-income category given the information contained in Table BCOAPO IR1 Q20d? If not, please justify the response.

Response:

The following shows the breakdown of customers (number and percent) for customers with annual usage over 18,000 kWh per year. Also shown is the breakdown for customers with all usage levels. Note that this is for the survey sample of customers. This information is not available for all customers on the system.

Table BCUC IR2 Q16.1.1

	Over 18,000 kWh per year	Customers at all usage levels
Income <$20k	3 2.7%	51 6.7%
Income $20k-$40k	24 21.2%	213 27.8%
Income $40k-$60k	18 15.9%	182 23.8%
Income $60k-$80k	30 26.5%	137 17.9%
Income $80k-$120k	22 19.5%	127 16.6%
Income >$120k	16 14.2%	56 7.3%

As the table above shows, nearly a quarter of the customers that have usage over 18,000 kWh per year also have income of less than $40,000 per year. Therefore it is not correct that it is impossible to be both a high usage and a low income customer. In fact, FortisBC is concerned that some of the customers with the highest usage and therefore largest bill impacts will also be low income customers. That is one of the reasons why FortisBC considered bill impacts in its proposed RIB rate and did not simply look for the option that would achieve the highest level of conservation savings.

16.1.2 In fact, from Table BCOAPO IR1 Q20d, it can be showed that customers with a household annual income of more than $120,000 consume on average 13,974 kWh annually (2,329 * 6). Therefore, does FortisBC agree that high-usage customers as defined in Table BCSEA IR1 Q4.1 would have an annual household income significantly higher than $120,000? If not, please explain why not.

<u>Response:</u>

The Company does not agree. Although the mean usage for customers is higher when income is higher, it cannot be concluded that all customers with large usage have high income levels or that high-usage customers would have an average income above $120,000.

Less than 15% of customers with usage over 18,000 kWh per year have incomes of $120,000 per year or more. Using the information provided in the response to BCUC IR2 Q16.1, a weighted income level was calculated assuming the mid-point of income levels for each range.

For income below $20,000 the value of $15,000 was used. For income above $120,000, a value of $150,000 was used. The resulting weighted income number was $74,000.

This compares to a weighted average income of $61,000 for all customers using the same method demonstrating that customers with usage over 18,000 kWh per year have an average income that is slightly above that for all other customers, but much less than the $120,000 per year level suggested by the question.

This information, along with that provided in the response to BCUC IR2 Q2.2 and Q2.3 above, would indicate that while there is some correlation between high usage and high income, there are many instances where high usage customers have low incomes. A RIB rate impacts large users the most, and will impact both low income and high income customers.

In practice, any price increases experienced by customer with lower incomes will be more onerous because the electric bill is a higher percent of total disposable income. Also, lower-income customers have fewer resources to pay the upfront cost to replace existing heat sources and other appliances with more efficient versions.

Because the RIB rate impacts customers across all income levels, FortisBC proposed Option 8 as its preferred rate rather than a rate design that has larger rate impacts for more customers. Option 8 was chosen, in part, because it limits the number of customers that see rate increases above 10%.

16.2 For the high-usage customers consuming more than 18,000 kWh annually, please provide the breakdown of customers (number and percentage) with electric heat and other heat.

<u>Response:</u>

The following provides a breakdown of customers with consumption over 18,000 kWh per year that have electric heat vs. another source. This is based on the survey sample data. By far the majority of customers with high consumption also have electric heat.

	Over 18,000 kWh per year	Customers at all usage levels
Electric Heat	86 67.7%	329 39.3%
Other Heat	41 32.3%	508 60.7%

17.0 Reference: Exhibit B-6, BCSEA IR 6.1

Table 7-2: RIB Rate Option Comparison

FortisBC states that Table 7-2 supports the conclusion that "RIB rate options with a higher threshold between Block 1 and Block 2 have higher conservation impact, other things being equal."

Commission staff disagree that Table 7-2 supports that conclusion and point to the following instances where Table 7-2 supports the contrary:

- Comparing Options 3, 9 and 6 that all have a Customer Charge of $28.93 and a customer bill impact criterion of "100% see < 10%", it can be seen that as the threshold increases from 1,350 to 1,600 to 2,100 kWh, the amount of conservation decreases.
- Comparing Options 2, 8 and 5 that all have a Customer Charge of $28.93 and a customer bill impact criterion of "95% see < 10%", it can be seen that as the threshold increases from 1,350 to 1,600 to 2,100 kWh, the amount of conservation decreases slightly.

17.1 Please confirm that Table 7-2 does not support the BCSEA conclusion and explain the relationship between the threshold and the amount of conservation, other things being equal.

Response:

FortisBC interpreted (or perhaps misinterpreted) part (b) of BCSEA IR 1.6.1 to be referring to the differential between block rate 1 and block rate 2. Generally speaking, although it is not possible to hold all other things equal, a higher differential is coincident with greater conservation savings.

The Company can confirm that in options with the same Customer impact and Customer Charge those with a higher threshold also have a higher conservation impact.

18.0 Reference: Exhibit B-6, OEIA IR 8.4.2

Plan to Implement TOU Rates

OEIA IR 8.4.2 mentions the plan for the implementation of time-based rates that FortisBC presented in its 2009 COS and RDA. Item #1 of the plan reads as follows: "Commission a study during 2009 and 2010 that examines the typical effects of time-based rates on energy and demand, as experienced by utilities that have already implemented or piloted them".

18.1 Please submit that study or provide an update as to the status of that study.

Response:

The AMI Future Program Study has been attached as Appendix BCUC IR2 18.1.

18.2 Item # 2 of the plan discusses the timing of the CPCN application for AMI. Does FortisBC still expect to be filing such application in 2011?

Response:

FortisBC still expects to file an AMI CPCN application in 2011.

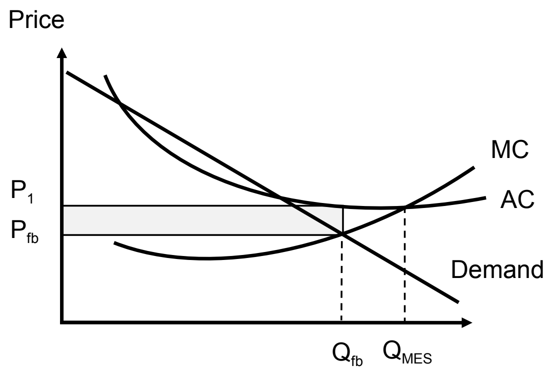
2. Marginal Cost Pricing

This section commences with an overview of marginal cost pricing before moving on to a discussion of the key costing concepts relating to marginal cost pricing, such as forward-looking costs, time horizons related to the measurements of costs (i.e., short run vs long run marginal cost) and different methodologies for estimating long run marginal costs in the context of the specific characteristics of the water business.

2.1. Overview of Issues

According to standard economic theory, prices should be set at marginal cost (MC) since, in the absence of externalities, this maximises economic welfare.[2] This is because such prices reflect the costs involved in providing an additional amount of output. Where the user values an extra unit more than it would cost to produce it, it is economically efficient to produce that unit, and vice versa. Setting prices equal to MC means that users will continue purchasing extra units until it is no longer economically efficient to produce them at that price. MC based pricing therefore send signals to consumers and producers encouraging them to balance the benefits obtained by consuming a good or service with the costs of providing it.

FIGURE 2.1: UNDER RECOVERY



In the context of the water it is typically the case that the business is a natural monopoly because the infrastructure cannot be economically duplicated. Average costs (AC) are falling in the relevant range (Figure 2.1). The minimum efficient scale (MES) is so large compared to demand that there is only room for one business.[3,4] The shapes of the cost curves reflect some very large fixed costs, say of building a dam or a water distribution network. MC is relatively low. As soon as the dam and distribution network has been established, it is relatively inexpensive to transport an additional unit of water over the network (e.g. pumping and chemical costs).

To set the price equal to MC is known as the first-best solution in terms of allocative (or demand-side) efficiency. The problem with this first-best solution, when dealing with a natural monopoly, is that it does not allow the utility to cover (fixed) costs because MC is

2 Note that we in this section do not explicitly distinguish between short-run and long-run costs. In section 2.3 we discuss short and long-run concepts.

3 This implicitly assumes that potential entrants face a similar cost structure.

4 In Figure 2.1 the MES is large relative to the size of the market depicted by the demand curve – suggesting a monopolistic market. However, a monopoly may face increasing average costs, at least over some output range. Whether a utility in fact has increasing average costs can be tested by calculating both average costs and marginal costs, since marginal costs per definition will be higher than average costs in this case.

less than AC in the relevant range. This is illustrated in Figure 2.1, where a price equal to P_1 would be required for full cost recovery. If prices were set equal to P_{fb}, under recovery would be equal to the shaded rectangle.

No standalone water utility could invest in infrastructure if prices were set equal to MC, unless compensated in some way e.g. by subsidies. Demand-side efficiency would be achieved at the expense of supply-side efficiency.

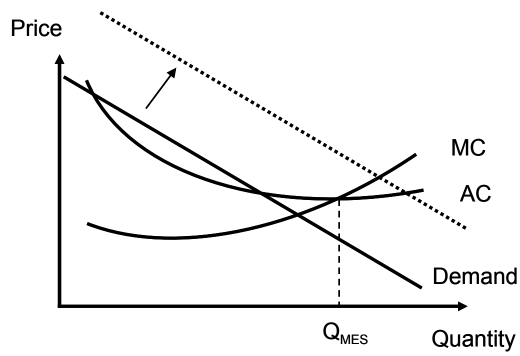
Coase's solution[5] to the competing needs of demand-side efficiency and supply-side efficiency was the introduction of a two-part tariff. Incremental consumption (e.g., per kL of water delivered) is priced at marginal cost but the fixed charge is set so that total revenue covers total costs.[6] In the Australian water industry, two-part tariff structures are now widely applied.

Thus, two-part tariff structures in Australia can be described by the following revenue requirement:

$$\textit{Revenue from annual charges} \;=\; \sum_{i=1}^{N}(A_i + C_i \times Q_i)$$

The first part of the tariff recovers the fixed portions (i.e., the connection and the access charges, denoted *A*) of the utility's annual costs. The second part recovers the variable, or marginal, costs of the operation by way of a volumetric charge (denoted *C*) multiplied by the quantity demanded (*Q*).

FIGURE 2.2: RISING AC



The discussion above assumes that average costs are not rising in the relevant output range and MC is below AC. As low cost water services are fully utilised, higher cost sources need to be added in order to meet demand growth, even though the business may have monopoly advantages. Moreover, as the area serviced expands, distribution and pumping costs may rise. Thus water business may face rising rather than falling average costs.

This is illustrated in Figure 2.2. Note that average costs rise due to a depletion of technological possibilities in production and not from diseconomies of scale. In other words, even if prices where set according to MC there would be not be room for an entrant to enter the market and provide services at a lower cost.

5 Coase R. (1946). "The Marginal Cost Controversy." Economica, 13 (8), 169-89.

6 We interpret "full cost recovery" as encompassing two broad types of costs – operating and maintenance costs and capital costs. Some may argue that there exists a third element – environmental costs, or externalities. Valuation of these costs will not be addressed in this report. From the perspective of the utility externalities are not of concern for cost recovery. Externalities are however, important from society's perspective.

Such a scenario is problematic for the implementation of a two part tariff. If the volumetric charge was set according to MC the business would over recovery costs. In a two-part tariff this could only be counteracted by a negative fixed charge. This is not practically feasible. Managers and/or regulators must therefore decide whether to trade-off demand-side efficiency by lowering the volumetric charge to average cost level or alternatively setting the volumetric charge according marginal costs while using other regulatory instruments to counteract the issue of over-recovery.

2.2. A forward-looking concept

Costing systems can be backward-looking, forward-looking, or a mixture of the two. Backward-looking systems are based on the historic cost basis. "Looking forward" implies that the expected development in prices, first of all asset prices, and expected development in demand will need to be taken into account.

Marginal cost pricing is a forward-looking concept. It depends on using estimates of future capital costs (or capital costs looking-forward) to calculate water charges, rather than historical costs. The simple rationale is that historical costs are “sunk costs” or cost which cannot be altered by changing current behaviour. In contrast future capital costs related to system expansion are costs that can be altered by increasing or decreasing water demands, notably by bringing forward or delaying capacity expansion.[7]

When calculating marginal costs, the costs associated with the existing system should therefore be ignored. As Kahn notes[8]:

> *“Marginal costs look to the future, not to the past: it is only future costs for which additional production can be causally responsible; it is only future costs that can be saved if that production is not undertaken.*
>
> *If capital costs are to be included in price, the capital costs in question are those that will have to be covered over time in the future if service is to continue to be rendered. These would be the depreciation and return (including taxes) of the future investments that will have to be made.*
>
> *These incremental capital costs per unit of output will be the same as average capital costs of existing plant only in a completely static world, and under conditions of long-run constant cost. As for the former and by far the important qualification, in a dynamic economy, with changing technology as well as changing factor prices, there is every reason to believe that future*

7 From a theoretical perspective, the use of forward-looking costs has the advantage: costs and capital are valued on the basis of an alternative (economic) cost approach, instead of an accounting costs approach. From an efficiency point of view this is very appealing, because a price based on opportunity costs sends the right signal to consumers about the value of the resources the consumer/the competitor/society is forgoing by using this service.

8 Kahn, A. (1988) The Economics of Regulation: Principles and Institutions, Massachusetts Institute of Technology, vol. 1, p. 98.

> *capital costs per unit of output will not be the same as the capital costs historically incurred installing present capacity*."

A forward-looking perspective implies the existence of a long term capital plan for the utility, an instrument required in any event for effective operation and planning.

2.3. Short-run vs. Long-run

Marginal cost can be estimated in either a long-run (LRMC) or a short-run (SRMC) perspective. The fundamental difference between SRMC and LRMC is the time frame under consideration and the implications for a firm's ability to adjust its production process to minimise costs. As noted by Turvey:[9]

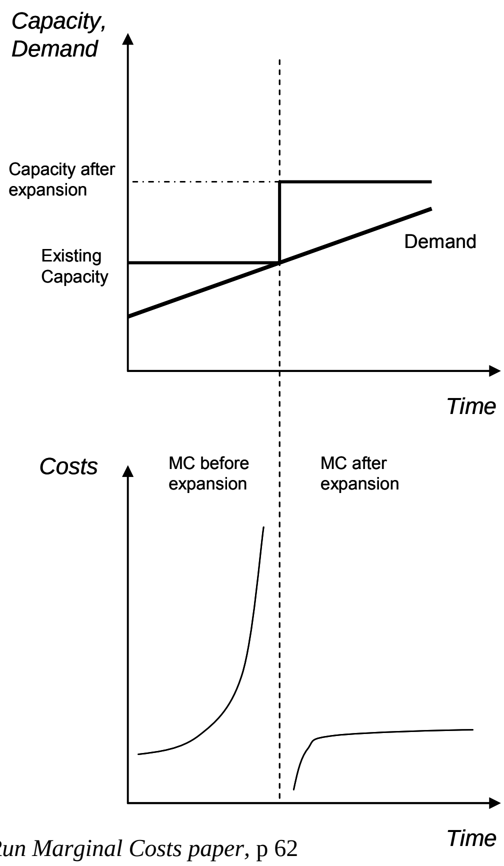
> *"…the term LRMC is used to signify the cost effect of a change which involves some alteration in the amount or timing of future investment. SRMC, on the other hand, takes capacity as given, so relates only to changes in operating costs for example when the transport of additional water requires only additional pumping costs."*

During water shortages, SRMC rises steeply, because production capacity is operating at limits of it design capability, or because inefficient production capacity has to be taken into service.[10] In the extreme case, additional supplies can only be secured for one customer by reducing supplies to another customer; SRMC then rises to the value of water to the customer who is not being served, rather than being defined by production costs. In contrast when there is excess capacity, SRMC will be very low.

This situation is depicted in **Error! Reference source not found.**, where marginal costs rise sharply in response to capacity constraints and then fall away as a result of significant excess capacity following expansion.

Recognition of the instability and implications of SRMC based pricing in terms of both pricing efficiency and equity means that long-run marginal cost (LRMC) is now preferred over SRMC as the appropriate basis for cost-reflective

FIGURE 2.2: VARIABILITY OF MARGINAL COSTS



[9] Turvey (2001), *Annex A: Some comment on Ofwat's Long Run Marginal Costs paper*, p 62

[10] The potential for increased costs in the short run can be exemplified by the problems experience by Yorkshire Water (UK) in 1995 during a drought. The drought resulted in severe stress to the water supply system, in the West Yorkshire districts of Bradford, Calderdale and Kirklees, necessitating the emergency measure of tanking in water from outside the region.

pricing. This was already recognised by Turvey (1969)[11] who criticised the standard use of marginal costs for inadequately incorporating time within the marginal capital cost function. Similarly, Mann et al. (1980)[12] notes that failure to consider the long-run will generate socially unacceptable instability in tariffs and charges over time.

In this respect it is necessary to understand the concept of long-run. The distinction between the short and long run in economics is purely conceptual - it does not correspond to any particular arbitrary time period. However, from a theoretical perspective the long run should be understood as *the time horizon where all costs are variable*. In practice, the long run has been interpreted in different ways including:

- the planning horizon;
- the average life of assets; or
- the time period until the next expansion to meet demand growth.

What constitutes the long run depends on the specific case we are investigating. If we are considering the fixed factor to be the size of the plant (or capacity), then the long run will (as a minimum) be the time period before the business undertakes investment in additional capacity.

In the water sector, investments tend to be lumpy, require building in of substantial spare capacity and are typically very long lived (up to 100 years). Water utilities must also meet certain obligations in terms of supply and quality. Consequently, setting efficient prices for water services requires consideration of the greater level of inflexibility inherent in the sector's infrastructure, which in turn suggests adopting investment planning periods of at least 20 years.

Since most water assets have an asset life (both physical and economic) in clear excess of 20 years it is important that calculations take account of this by including a residual value to ensure that the values of the assets are properly reflected at the end of the planning period.

Where major augmentation is scheduled to occur close to the end of the planning period, there is an issue as to whether the assessment should be truncated just prior to that augmentation, or alternatively, where a major augmentation is expected to occur just following the end of the planning period to extend the period to include it. However, with a planning period of 20 years and the inclusion of a residual value any expansions occurring close to the end of this period will have very limited influence on the final results. Nevertheless, if the intention is to signal the average cost of lumpy additional capacity, rather than the marginal cost of the first increment in demand serviced within in the planning period, the planning period should not be truncated but extended to include the augmentation.

[11] Turvey, Ralph, "Marginal Cost", Economic Journal, Vol. 79, pp. 282 – 299, 1969.

[12] Mann, Patrick C., Saunders, Robert J., Warford, Jeremy J. "A Note on Capital Indivisibility and the Definition of Marginal Cost", Water Resources Research Vol. 16, No. 3, pp. 602-604, June 1980.

2.4. Estimation of Marginal Costs

From a practical perspective, LRMC can be defined as including both short-run and long-run costs. LRMC may therefore be disaggregated into two main types of marginal costs: Marginal *Operating Costs* or MOC (short-run); and Marginal *Capacity Costs* or MCC (long-run), associated with bringing forward investment projects.[13]

MOC are generally simpler to estimate than MCC, as they usually have a more easily defined relationship with incremental increases in demand. In water, marginal operating costs are typically related to the cost of electricity and chemicals. Note, however, that SRMC is a forward-looking concept and in theory entails an estimation of possible future outcomes and associated costs. SRMC may also curve upwards above 'pure' operating costs in situation where demand exceeds supply. For all practical purposes in the water industry, however, estimating SRMC by reference to operating costs seems a reasonable proxy.[14]

Estimating MCC is more difficult. These are the costs associated with investments as a result of an incremental increase in demand.

MCC can be estimated in different ways. QCA has previously examined some of these issues in its consideration of the pricing of bulk water services provided by GAWB. Specifically, QCA has considered whether LRMC should be defined as average incremental costs (AIC) or according to the methods referenced to Turvey[15] including the "perturbation" method or Present Worth of Incremental System Cost (PWISC) method. We find this latter collection of terms neither informative nor simple and therefore use the term Marginal Incremental Cost (MIC) method.[16]

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[13] This separation of into a short-run and long run component suggests that SRMC will always be below LRMC. However, as we have seen in **Error! Reference source not found.** SRMC may rise substantially in the event of scarce capacity and may therefore increase above LRMC. In general, SRMC is below LRMC only in the presence of excess capacity.

[14] In practice, SRMC may be estimated based on existing operating costs or following a capacity expansion path.

[15] The concept of Turvey marginal cost is not well defined in the literature. Turvey has proposed a number of variations of his preferred methodology for estimating LRMC. For example in Turvey (1976) he includes a numerical example in which he amortises the present value of the capital expenditure and divides by the demand volume. This always gives a higher LRMC estimate than the formula given in the PWISC formula used here. The PWISC definition is by Mann et al. (1980), which is sourced from Turvey, R., "*Optimal Pricing and Investment in Electricity Supply*", George Allen and Unwin, London, 1968. Note that in this source, there is an implicit assumption that investments take place every year. However, PWISC may of course be defined in terms of any increment of output.

[16] The insight that Turvey is a marginal incremental cost can be illustrated by rewriting the most common form of the Turvey formula (see section 2.4.1) as:

$$\frac{\partial I}{\partial t} \bigg/ \frac{\partial Q}{\partial t} \quad = \quad \frac{\partial I}{\partial t} \times \frac{\partial t}{\partial Q} \quad = \quad \frac{\partial I}{\partial Q},$$

where both the cost and the demand increments are expressed as present values. This common formulation of Turvey's measure illustrates that his measure of incremental costs is concerned with smaller rather than larger increments in demand.

There are, however, a number of other concepts related to the measurement of LRMC used in a regulatory setting. These are LRIC (Long Run Incremental Cost), LRAIC (Long Run Average Incremental Cost), TSLRIC (Total Service Long Run Incremental Cost) and TELRIC (Total Element Long Run Incremental Cost). In practice, the four concepts are related and often used interchangeably. Unless specifically stated, we will therefore refer to LRIC which should be understood as encompassing all four concepts.

In the following we discuss the three cost concepts MIC, AIC and LRIC. We commence with MIC and AIC as these historically have been applied to the water industry. An overview of selected cost concepts, including a brief evaluation of each, is provided in Appendix A. Formulas are summarised in Appendix B.

2.4.1. Marginal Incremental Costs - MIC

MIC may be defined as the difference in the present values of the investment programs with and without an incremental increase in demand. In this case the Marginal Capacity Cost (MCC) component of the MIC will be relatively low when capacity utilisation is low and the next investment project is some distance in the future, but will rise as capacity utilisation increases and the timing of the next project draws nearer to signal the magnitude of the forthcoming investment. Thus, MIC has some of the familiar characteristics of SRMC i.e., instability and saw-tooth changes.

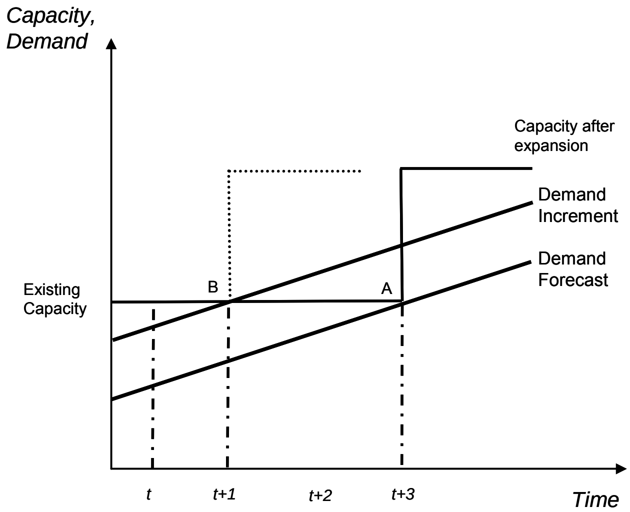
Turvey's[17] methodology for estimating the MIC may be summarised as:

1. forecast the relevant expected demand into the foreseeable future;
2. estimate the system requirements and augmentations that would be required over time to meet expected demand levels;
3. estimate the likely cost of these requirements;
4. adjust the demand upwards by an increment;
5. reconsider the system requirements and augmentations that would be required to meet this new demand pattern and their associated costs; and
6. calculate the MCC as the difference between the net present values of the investment program(s), divided by the total increase in demand.

This framework is illustrated in Figure 2.3 below.

[17] Turvey, R, *What are marginal costs and how to estimate them*, Undated and Turvey (1976), *Analyzing the marginal cost of water supply*, Land Economics, 71(4), 158 – 168.

FIGURE 2.3: FRAMEWORK FOR ESTIMATING MIC



Turvey marginal cost is based on the axiom that, given some growth in demand, additional capacity increments cannot be totally avoided, but can be postponed (advanced) with reductions (increases) in annual demand. The marginal capital cost is therefore the change in the present worth of the next increment in capacity divided by the change in annual demand necessary to postpone (or advance) the building of that capacity increment.

In practice this means that the MCC is the cost in net present value terms of moving the next planned capacity augmentation forward by a single year and then dividing the cost by the one-off volumetric increase (or increment) in current demand that would require the planned capacity augmentation to be moved forward. This is illustrated by the formula below:

$$MIC_t^{MCC} = \frac{NPV_t(capex) - NPV_{t+1}(capex)}{\Delta demand}$$, or more formally

$$MIC_t^{MCC} = \left[\frac{I_j}{(1+i)^{j-t}} - \frac{I_j}{(1+i)^{j+1-t}}\right] \Big/ \left[Q_{t+1} - Q_t\right],$$

where t = year for which MIC is being calculated

I_j = capital expenditures in year j (the year in which the next large investment expenditures takes place or the year in which the system reaches capacity)

i = the opportunity cost of capital

Q_t = water demand in year t

Note that the MIC definition does not look beyond the next lump of investment, and therefore ignores the effect on unit costs of subsequent increases in output.

With regard to the estimation of the SRMC or MOC, the MIC approach may be illustrated as follows:

$$MIC_t^{MOC} = \frac{\Delta opex}{\Delta demand}$$, or more formally

$$MIC_t^{MOC} = \frac{O_{t+1} - O_t}{Q_{t+1} - Q_t},$$

where O_t is the operating expenditure in year t. SRMC under the MIC approach is therefore the change in operating expenditure divided by the change in demand, where the increment taken is the change in output that occurs during one year.[18]

2.4.2. Average Incremental Costs - AIC

Another way to calculate the MCC is the Average Incremental Cost (AIC) method.

This method has been proposed by Mann et al. (1980).[19] In this paper they note that AIC is calculated by:

> *"discounting all incremental costs which will be incurred in the future to provide for estimated additional demand over a specified period, and dividing that by the discounted value of the incremental output over the period"*

In other words, AIC is the present value of the stream of (least cost) capital expenditure needed to satisfy the projected demand divided by the present value of the stream of demand itself. For an individual unit, the Incremental Cost (IC) is divided by the number of units in the increment to get the AIC.

The basic methodology for estimating the AIC may thus be summarised as:

1. forecast the relevant expected demand characteristics into the foreseeable future;
2. estimate the system requirements and augmentations that would be required over time to meet expected demand levels;
3. estimate the likely cost of these requirements; and
4. calculate the MCC as the average cost per unit of anticipated demand of the total increment to capacity required the forecast period.

As a formula the AIC method for MCC may be illustrated as follows:[20]

$$AIC_t^{MCC} = \frac{NPV(Capex)}{NPV(Demand)}, \text{ or more formally}$$

$$AIC_t^{MCC} = \sum_{k=1}^{T} \left[\frac{I_{t+k-1}}{(1+i)^{k-1}} \Big/ \frac{Q_{t+k} - Q_t}{(1+i)^{k-1}} \right]$$

---

18 This definition is a discontinuous version of the traditional continuous micro-economic definition of SRMC, where it is a derivative of the total cost function and therefore expresses the 'true' cost of an additional unit.

19 Mann et al. (1980) source their definition of AIC from Saunders, R. J. and J.J. Warford, *Village Water Supply: Economics and Policy in the Developing World*, John Hopkins University Press, Baltimore, Md., 1976.

20 The formula may also simply be written:

The notation is similar to that used in the previous section except that T is the number of years for which water expenditures and demand are forecast (the planning horizon). In contrast, under the MIC approach, the capital expenditure only relates to the next augmentation. The other major difference is that under the AIC method account is taken of incremental demand over the whole planning period whereas under the MIC approach the demand is simply the incremental demand in the first year.

The AIC definition thus gives marginal cost estimates which smooth out lumps in expenditure over time while at the same time reflecting the general level and trend of future costs which will be incurred as water consumption increases.

With regard to the estimation of MOC, the AIC approach may be illustrated as follows:

$$AIC_t^{MOC} = \frac{NPV(opex)}{NPV(demand)}\text{, or more formally}$$

$$AIC_t^{MOC} = \sum_{k=1}^{T}\left[\frac{O_{t+k} - O_t}{(1+i)^{k-1}} \Big/ \frac{Q_{t+k} - Q_t}{(1+i)^{k-1}}\right]$$

SRMC under the AIC approach is therefore the present value of the stream of incremental operating expenditure needed to satisfy the projected demand divided by the present value of the stream of demand itself. This is in contrast to the MIC approach that only considers the increment of change in output which occurs during one year.

2.4.3. Long Run Incremental Cost – LRIC

Long run incremental costs may be calculated as:[21]

$$TB\ LRIC_t^{MCC} = \frac{Annuitised\ capex}{\Delta demand}\text{, or more formally}$$

$$TB\ LRIC_t^{MCC} = \left[\frac{i}{1-\left[1/(1+i)\right]^n} \times I_j\right] \Big/ \left[Q_{j+1} - Q_j\right]$$

where n refers to the (economic) life of the investment and j again refers to the year in which the next major investment is completed. The investment I is multiplied by a capital recovery or annualisation factor, in this case an annuity factor. This definition is also sometimes referred to "Textbook" LRIC (TB LRIC).

21 Based on Mann et al. (1980).

As defined above TB LRIC does not extend beyond the next investment. However, it could be redefined to look at the average of the next of several investments.

As a result, during the years t through j TB LRIC^{MCC} will remain constant. At year j+1, j is reassigned to be the next year in which a large investment takes place. In this respect LRIC changes immediately following a new investment to reflect the incremental cost of the next capacity investment.

SRMC in the context of TB LRIC is the same as defined under MIC above.

While the LRIC definition above is concerned with an increment to an existing plant (or an increment on an increment), the practical implementation of LRIC takes another form in the regulation of the telecommunications sector. Here LRIC may be defined as follows:

$$TEL\ LRIC_{t,m}^{MCC} = \left[\frac{i}{1-\left[1/(1+i)\right]^n} \times I_{t,m} \right] \Big/ Q_{t.m}\ ,$$

where subscript m refers to a particular service. In other words, the annual capital cost required to produce service m, where demand is Q_m. Again it is important to stress that LRIC in telecommunications is not concerned with an increment to existing capacity but entails a re-dimensioning and hence re-costing of the existing network. To arrive at the unit cost estimate costs related to m are therefore not divided by an increment in demand but by total demand for the particular service. SRMC under this definition is simply the annual operating expenditure relating the particular service.

The increment is often defined as a whole group of services using the network. In this regard TSLRIC refers to the increment in costs occurring in the long run of offering a complete (total) service in addition to other services. In contrast, TELRIC refers to the increment in costs caused by identifiable elements that are needed in the production of a service, like switching or transmission between switching centres or a certain advanced function implemented in the switch. While TSLRIC and TELRIC may differ in theory, the approach taken to estimate both types of cost in practice means that they yield similar results.

The main argument for using this LRIC approach is that the cost (or access price) of services should not distort the build/buy decision of new entrants. Entrants will be encouraged to use existing facilities if, and only if, it is economically desirable to do so. Just as important, access charges based on these principles also mean retaining investment incentive for incumbents to upgrade or extend the existing network when new technology is available. When charges are set on this basis, infrastructure competition is encouraged in those areas where it is efficient to have competing infrastructure, whereas service competition is encouraged in those areas where the investment in competing infrastructure is not efficient.

This interpretation of LRIC in telecommunications and departure from the textbook version of LRIC is a result of practical difficulties in modelling and calculating the service costs related to the access services based on additions to the existing network and signalling costs faced by entrants that are changing rapidly due to technology developments. Given the nature of water and wastewater infrastructure, such problems are nowhere as critical in the water industry. Moreover, the use of "full service", as typically used, moves LRIC towards an average cost concept rather than marginal cost measure.

2.4.4. Comparison of MIC, AIC and LRIC

The approaches outlined above considered the concept of marginal costs from different perspectives.

While AIC calculates the level at which future increments of output must be priced to ensure total incremental cost recovery given forecast demand, the MIC method considers the change in forecast capacity costs arising from a permanent increment or decrement in the forecast demand. "Textbook" LRIC is the annualised cost of the next proposed investment measured relative to incremental demand.

In this respect, the MIC method is often stated as being more explicitly concerned with 'decision making at the margin'[22] and within the increment. This feature also has the effect of increasing price instability, as prices are more directly adjusted to send the 'correct' economic signals. In contrast, AIC is based on a long term planning period and therefore has the property of dampening price changes over time (even in the event of new investment) and hence ensuring stable prices. LRIC on the hand will be constant until a new investment takes place where it will be adjusted to reflect new investment. AIC, therefore, is distinguished from LRIC and MIC by the fact that it takes a longer view of costs.

2.5. Least Cost Schedule

A common feature of the definition of the approaches is that they assume that the investment (or series of investments) necessary to meet output have been optimised. This means that the resulting costs are such that a least cost schedule is created.[23]

In principle, there are number of ways to achieve this "optimal" cost schedule. One way is mathematical modelling involving operations research and multi-period linear programming. Any mathematical model, however, is a simplified representation of the real world and as such may fail to accurately solve the problem. In addition, algorithms may be incorrectly specified, input values inaccurately estimated etc. Without expert input it may be difficult to implement more advanced forms of numerical analysis in practice, while providing confidence in the results.

[22] Decision making at the margin refers, for example, to neo-classical economic decision making where individual consumers and producers make decisions by equating marginal private benefit to marginal private cost and decision making at the society's level is made by equating marginal social benefit to marginal social cost.

[23] Note that economic efficiency requires that services are always produced using the least cost method of production.

From a practical perspective, it may therefore be more appropriate to rely on general business skills when developing a least cost schedule. This could entail using different investment analysis techniques, ranking expansion alternatives on whole-of-life, annualised cost per unit (eg. annual yield for a dam, peak day capacity for WTP, peak hour capacity for balancing storages and peak flows per second for pipelines and rising mains.

For example, using AIC methodology the following approach could be adopted:

- develop a detailed model of future demand for water services;
- project the base case demand for 30 years into the future;
- develop potential demand management options;
- calculate the LRMC of different options investment options and rank the alternatives; and
- choose the least cost schedule.

2.6. Summary

From an efficient pricing perspective taking into account both demand and supply side efficiency the charges should be so that:

$$\textit{Revenue from annual charges} = \sum_{i=1}^{N}(A_i + LRMC_i \times Q_i)$$

This two part tariff structure ensures that:

- the demand side efficiency criterion is met by sending efficient signals to the customers through the marginal costs of operation taking into account a forward-looking charge for future capital expenditure and incremental changes in operating costs; and
- the supply side efficiency criterion is met by using the fixed charge as a balancing item to ensure full cost recovery.

Note that contrary to what has been assumed in the previous sections, demand may be declining or constant. In this case the volumetric charge component is still LRMC. However, LRMC will not include any capital expansion costs and hence be to equal to SRMC.

The question then remains how best to estimate the LRMC?

Above we have discussed three distinct approaches: the Marginal Incremental Cost (MIC) method, Average Incremental Cost (AIC) method and Long Run Incremental Cost (LRIC) method. All methods have been developed to solve problems of capacity indivisibility and price instability over time. Indivisibility of capacity is a condition typical of water businesses, where capacity is often installed meet future demand for a number of years hence. Construction costs are high in relation to operating and maintenance costs. Strict marginal cost pricing would therefore result in significant fluctuations in price, which in turn would be source of considerable concern for customers.

MJA's analysis indicates that the AIC method is likely to be more stable over time. Hence from a price stability objective the AIC method is preferred.

However, before reaching a firm preference for one method over the other, it is important to understand and assess a range of practical issues associated with the implementation of the approaches. Since AIC and MIC are the two methodologies most often employed in the water industry, we focus our attention on these in the following section.

NAVIGANT

ADVANCED METERING INFRASTRUCTURE (AMI) FUTURE PROGRAM STUDY

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March 2011

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Executive Summary

Many utilities throughout North America are in the process of rolling out advanced metering infrastructure (AMI) to provide both system operating benefits and enhanced programs to allow customers to better manage their energy usage and costs. In this report, we examine and synthesize results from more than 50 different utility pilots and programs regarding the energy and capacity that could be realized through programs enabled by AMI. These programs include the following:

- **Time-of-Use (TOU)** – rates vary time period and season reflecting the cost of providing electricity during different time periods
- **Critical Peak Pricing and Critical Peak Rebate (CPP/CPR)** – customers are charged (pricing) or provided and incentive (rebate) for usage during critical peak periods as defined by both reliability and economic considerations.
- **Inclining Block Rates** – customers are charged higher rates for any usage that exceeds a threshold amount.
- **Pre-pay** – Customers pre-pay for their electricity consumption.
- **Load Control (LC)** – switches are installed on appliances to limit the use of those appliances during peak periods.
- **In-home displays (IHD)** – the household is provided with a device showing their current electricity usage and costs, providing real-time feedback.

Based on our review of the more than 50 pilots and programs of these options, we estimate that the programs can provide significant capacity and energy benefits to Fortis BC as summarized in Figures Figure ES-1: Capacity Savings (MW) in 2018 by Program Scenario and Figure ES-2: Energy Savings (GWh) in 2018 by Program Scenario. The "with supporting" technology indicates the conservation rates and pre-pay programs also include in-home displays (IHD) and either 4 load control switches or smart appliances. The supporting technologies scenarios substantially increase the energy and capacity from the conservation rates and pre-pay programs, particularly for the opt-out scenarios. The supporting technologies opt-out scenarios both increase the responsiveness of the conservation and prepay participants but also support energy and capacity savings from the customers who do not participate in the conservation rates and pre-pay programs. These forecasted benefits are based on the savings per participating customer as identified in Table ES-1: Per Participant Savings for Possible AMI Future Programs and the range of forecasted participation rates as summarized in Table ES-2: Participation Rates by Program and Scenario.

Figure ES-1: Capacity Savings (MW) in 2018 by Program Scenario

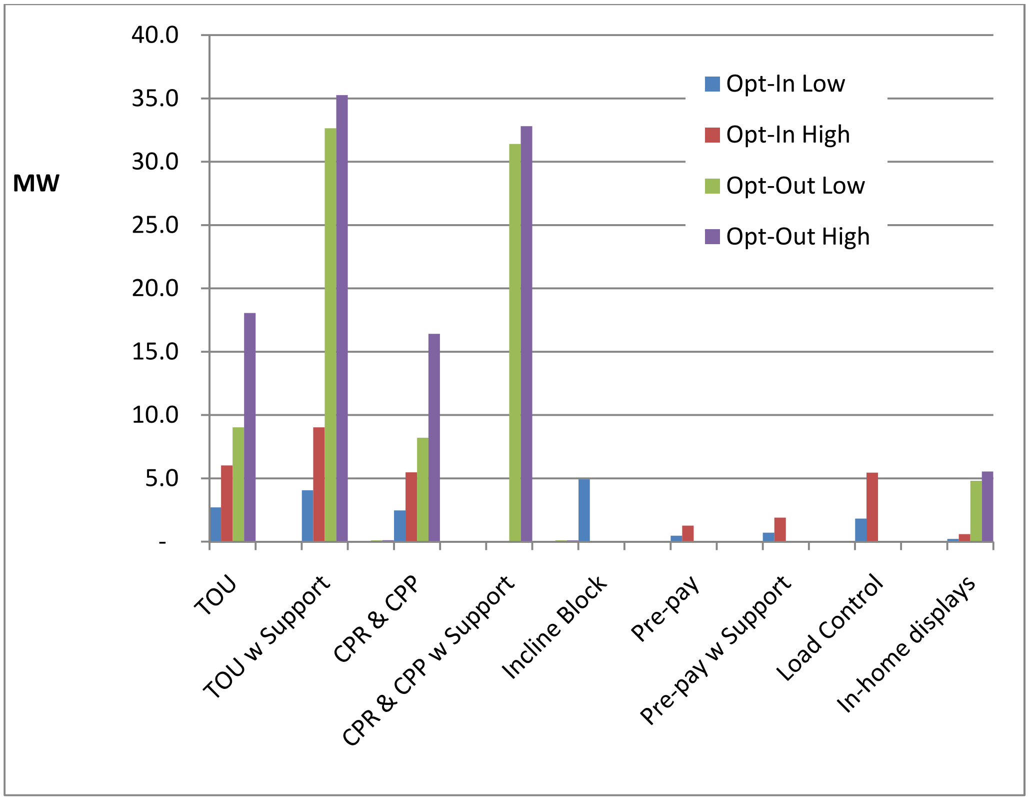

Figure ES-2: Energy Savings (GWh) in 2018 by Program Scenario

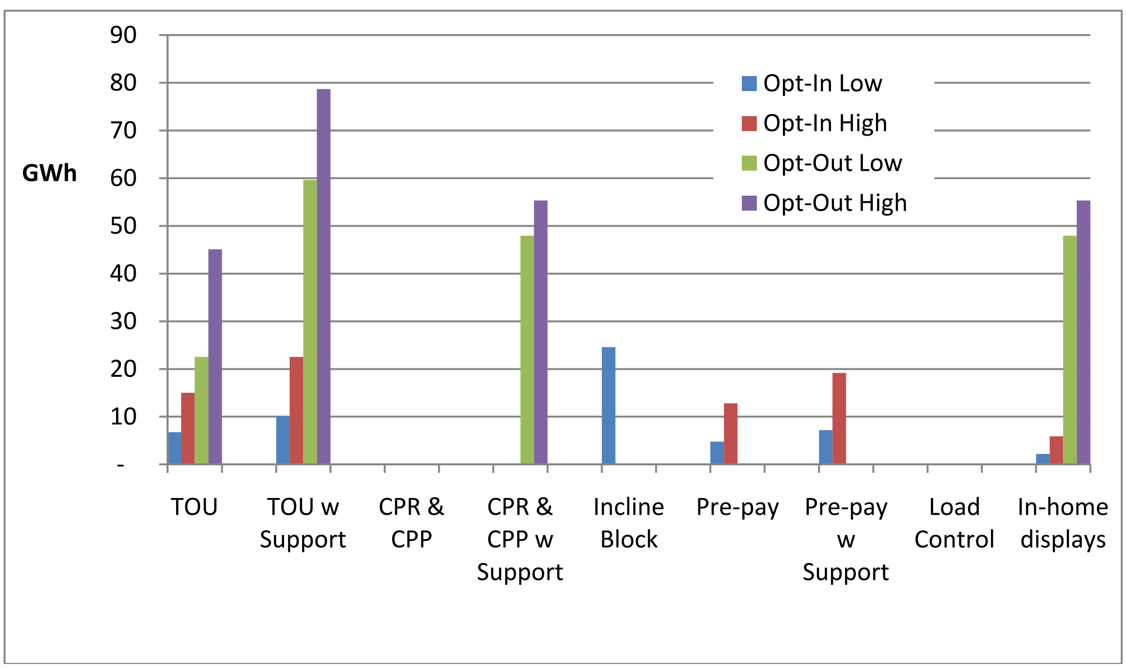

Table ES-1: Per Participant Savings for Possible AMI Future Programs and the range of forecasted participation rates as summarized in Table ES-2: Participation Rates by Program and Scenario.

Table ES-1: Per Participant Savings for Possible AMI Future Programs

Program Type		Peak	Energy	Source
Conservation Rates	**TOU**	11%	5.5%	BC Hydro CRI[1]
	CPP/CPR	10%	0	
	Inclining	1.8%	1.8%	BC Hydro CRI[2]
Pre-Pay		5.8%*	11.7%	Woodstock Hydro 2004[3]
Load Control		13.3%	0	FERC 2009
In-Home Displays		2.7%	5.4%	ACEEE 2010

* Assumed that the peak period savings are half of the annual savings

The evaluation of utility programs demonstrates that significant benefits can be realized through the implementation of AMI future programs functionality. Conservation reductions with supporting technology range with from of $395 to $1389 per customer for FortisBC. The analysis shows that:

- Inclining block rates provide the smallest benefits. Since FortisBC plans to roll-out TOU rates in 2014, and rate changes create customer confusion, there is little value to rolling out inclining block rates as an interim program.
- The research shows that on-going communication and marketing is essential for maintaining the behavioral savings. An on-going communication and marketing program (and the associated annual costs) need to be part of the program. The capacity and energy savings benefits and customer costs analysis included applicance on-going communication and marketing costs.
- The supporting technology (IHD) and appliance controllers produce substantial additional benefits regardless of the underlying rates and should be deployed as part of any program.
- TOU supplemented with supporting technologoes provides the greatest savings at the lowest costs per participating customer.

[1] B.C, Hydro, 2010 "Conservation Rate Initiative", BC Hydro Website
[2] B.C, Hydro 2008, "2008 Residential Inclininy Block Application," February, 2008
[3] Average of range from Woodstock Hydro, 2004. "Pay-As-You-Go-Power: Treating Electricity as a Commodity," Ken Quesnelle (Vice-President), January 20, 2004

Table ES-2: Participation Rates by Program and Scenario summarizes the program participation rates by program type and scenario. Most of the recent residential pilot programs to date have been conducted with volunteers, i.e. customers opted to participate. Thus, the reported savings represent results for the average participant. In a full-scale program, not all customers will participate. Since there are considerable ranges, uncertainty and a paucity of data on participation rates: high and low participation assumptions were developed for both an opt-in (i.e. voluntary) and an opt-out (i.e. mandatory) program. The participation rate assumptions for the in-home displays parallel the assumptions developed by the ACEEE in their meta-analysis of real-time feedback programs. The pre-pay and load control participation rates were selected to bracket the range of participation rates from the programs reviewed. Similarly, the participation rates for the opt-in conservation rates programs bracket the range from the programs and pilots reviewed. For the opt-out (or mandatory) programs one needs to recognize that some customers placed into conservation rate programs will not respond to the price signals. The low-end of the opt-out scenario is based on reconciling savings estimates from mandatory and voluntary programs and from very limited data on participation rates. The high-end participation rates for the conservation rates reflect the ACEEE assumptions for opt-in for real-time feedback (in-home displays).

Table ES-2: Participation Rates by Program and Scenario

<table>
<tr><th rowspan="2"></th><th colspan="2">Opt-In</th><th colspan="2">Opt-Out</th></tr>
<tr><th>Low</th><th>High</th><th>Low</th><th>High</th></tr>
<tr><td>TOU</td><td rowspan="2">9.0%</td><td rowspan="2">20.0%</td><td rowspan="2">30.0%</td><td rowspan="2">60.0%</td></tr>
<tr><td>CPR & CPP</td></tr>
<tr><td>Incline Block</td><td colspan="4">Not Applicable</td></tr>
<tr><td>Pre-pay</td><td>3.0%</td><td>8.0%</td><td colspan="2" rowspan="2">Not Applicable</td></tr>
<tr><td>Load Control</td><td>5.0%</td><td>15.0%</td></tr>
<tr><td>In-home displays</td><td>3%</td><td>8%</td><td>65%</td><td>75%</td></tr>
</table>

Project Background

Background

In 2008, the BC Utility Commission (BCUC) denied FortisBC's application for implementation of Advanced Metering Infrastructure (AMI) throughout its service territory.[4] One of the reasons for the denial was that the application did not have enough cost and benefit information on the long-term vision associated with AMI.

At this time, there are a substantial number of published studies and pilot program evaluations describing the probable benefits from rates and other programs enabled by AMI. Navigant Consulting, Inc. (NCI) was engaged to provide FortisBC with an analysis of the estimated energy efficiency and demand reduction that could be realized through future AMI-enabled programs. These results are to be used as components of the new AMI business case and Application.

Scope and Objectives

The objective of this effort was to develop an analysis of the net additional benefits that could be realized within the residential market by the deployment of AMI. The components of the benefit-cost analysis include:

- The range of benefits that could be delivered by the advanced functionality of AMI focusing on near- and mid-term applications including load control (LC), time-of-use (TOU), and conservation rates;
- Customer-side costs;
- Utility infrastructure, marketing and education costs; and
- Reduction in energy and capacity purchase to meet the customer requirements.

To develop the data and estimates, NCI reviewed and summarized the experience and results from other utilities' pilots, studies and programs. The scope of this effort was focused on enhanced AMI programs. FortisBC is incurring the costs developing the rate designs and implementing meter data management (including data validation, estimation and editing – VEE) as part of its AMI application, so these costs were not included. For the purposes of this analysis, enhanced functionality was defined to include (and not include) the items as summarized in Table 1: Summary of Project Scope.

[4] British Columbia Utilities Commission, Letter regarding Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project. Order No. G-168-08. 2008.

Table 1: Summary of Project Scope

In Scope	Out of Scope
• Estimating the impact of conservation rates • Estimating the impact of direct load control (DLC) that is specifically enabled by AMI • Estimating the impact of supporting technologies (e.g., in-home displays – IHD, smart thermostats, and smart Appliances) • Estimates of the price elasticity of demand for residential customers based upon synthesis of AMI pilots/deployments • Estimates of costs that are incurred to enable this functionality, over and above the baseline AMI system	• Estimates of AMI baseline deployment costs • Costs associated with designing rates and implementing a meter data management system with VEE • Costs associated with the communicating dynamic prices to the customer premises • Estimates of AMI benefits such as: — Remote connects and disconnects — Outage notification and restoration notification — Tamper/theft detection • Estimates and impacts of Longer-term AMI-enabled functionality such as: — Plug-in hybrid electric vehicles — Customer-sited renewables (e.g., photovoltaics)

Methodology

NCI has evaluated other utility programs as the basis for developing the estimates of the energy and capacity savings resulting from enhanced AMI functionality. Specifically, we have used a combination of secondary research and primary research to support the program review, as described below:

- Secondary Research – Evaluated and synthesized results from relevant studies on the impacts of AMI-enabled programs that affect customer demand and energy consumption. These included published summaries of utility AMI pilots to document the benefits related to load shifting and conservation as well the corresponding costs.
- Primary Research – Interviewed 5 relevant utilities, to understand their experience, benefits and costs, and lessons learned related to AMI future programs.

Experiences in California, Ontario and other pilot programs throughout North America indicates that AMI enables the development and deployment of programs (e.g., time-of-use rates, critical peak pricing, and load control) that provide energy and demand reductions with real economic benefits to both the utility and the customer. While the focus of this study, as well as most of the other AMI studies and pilots has been on demand response (DR), pricing and load control (LC), data from AMI may also be useful for targeting and improving the focus and effectiveness of FortisBC's current and future Energy Efficiency (EE) programs This additional value from AMI is not quantified in this report.

NCI developed estimates of the energy and peak load savings for various future conservation rates and load control programs that would be enabled by AMI per participating customer. There are multiple pilots and studies with relatively consistent estimates of energy and capacity savings per participating customer (when expressed as a percent of their peak demand or annual energy use).

To estimate impacts of a system-wide offering, participation forecasts are required. There is very limited data on participation rates. Most pilots recruited customers to volunteer and did track data on how many customers were not willing to participate. There are a few studies where customers were assigned to programs randomly, allowing us to infer participation rates.

Based on the ACEEE meta-analysis described later in this document, NCI developed four participation scenarios based on the limited data available: low and high participation for both an opt-in and an opt-out program[5]. "Opt-in" refers to the approach of offering a program as an option where the customer must explicitly sign-up or enlist. "Opt-out" refers to the approach where the customer is automatically placed in the program unless they explicitly request to be excluded.

A range of potential and energy and capacity savings were forecasted for each program type as the product of the: (a) per participant savings: (b) program scenario participation rate; (c) the number of residential customers; (d) average use (and demand) per residential customer; and (e) program ramp rate (the number of years from program launch until the program penetration is attained). The results include high and low energy demand savings among Fortis' residential customer base by program type for both opt-in and opt-out scenarios.

Future Programs Enabled by AMI

Enhanced AMI functionality enables the deployment of several different strategies designed to reduce peak demands and/or conserve energy through empowering and incenting customers to manage their electricity usage. In this analysis, we examined three broad categories of future AMI enabled programs, including: (1): conservation rates; (2) in-home displays (IHD); and (3) load control (LC). In this section we provide brief description of representative offerings to residential customers within each area.

Conservation Rates

With the deployment of advanced metering, utilities are increasingly implementing alternative conservation rates deigned to encourage demand reduction and energy conservation, including:

- <u>Time-of-Use (TOU) rates</u>—Electric rates vary by time of day and season. The prices for each time period are fixed. Customers can reduce their electricity bills through

[5] "Opt-in" refers to the approach of offering a program as an option where the customer must explicitly sign-up or enlist. "Opt-out" refers to the approach where the customer is automatically placed in the program unless they: (1) explicitly request to be excluded; or (2) don't advantage of any aspects of the program – implicitly opting out.

conservation and/or shifting loads to lower cost time-periods. Figure 1: Sample TOU Rates includes an example TOU rate from one of the pilots in Ontario.

Figure 1: Sample TOU Rates

Time	Summer Hours (Aug 1 - Oct 31)	Price/ kWh	Winter Hours (Nov 1 - Feb 28)	Price/ kWh
Off-Peak	10 pm - 7 am weekdays; all day on weekends and holidays	3.5¢	10 pm - 7 am weekdays; all day on weekends and holidays	3.4¢
Mid-Peak	7 am - 11 am and 5 pm - 10 pm weekdays	7.5¢	11 am - 5 pm and 8 pm - 10 pm weekdays	7.1¢
On-Peak	11 am - 5 pm weekdays	10.5¢	7 am - 11 am and 5 pm - 8pm weekdays	9.7¢

Note: *Rates reflect the Regulated Pricing Plan TOU structure from Ontario Energy Board's Smart Pricing Pilot*
Source: IBM and eMeter, 2007

- Dynamic Pricing (DP) – Includes several types of rate programs where the prices change can change based upon current market conditions (both wholesale prices and/or reliability considerations). Price signals are transmitted to customers and the customers make usage decisions (perhaps, using programmed controllers or thermostats) based upon the current price. There are three major types of dynamic pricing: (1) critical peak pricing (CPP); (2) critical peak rebate (CPR): and (3) real-time (RTP) pricing. This report only examines the potential benefits of CPP and CPR and does not include the costs of communicating the time-varying prices to the customers. Brief definitions of these three types of dynamic pricing programs are provided below:
  - Critical Peak Pricing (CPP) —During critical periods (defined by reliability and/or market conditions), the customers' usage is billed at the critical peak price. CPP rates can be used with standard or TOU rates. Typically, the prices are set at predetermined level for a fixed time period with limits set on the number of times the critical-peak event can be called. Increasingly, the CPP programs may include linkage to customer home area network, and appliance controls to automatically adjust usage during events. For, example some utilities are deploying smart thermostats that adjust temperature settings, based on the customers' preferences, during the critical periods. Customers may opt to override the controls and pay the CPP for the added consumption.
  - Critical Peak Rebate (CPR)—Similar to the CPP except that the customer receives a credit or rebate for reducing usage during the critical peak period rather than paying a premium price for usage. CPR programs have similar demand reductions as CPP programs and appear to have much greater

acceptance among residential customers. CPR programs may entail higher utility administrative costs and complexity than CPP rates.

- Real Time Prices (RTP) – Prices change hourly based upon the hourly wholesale market prices. RTP rates are usually offered only to the large commercial and industrial customers. For this reason, they are not further discussed in this report.

- Inclining Block—Electric rate that requires customers to pay more for higher usage. These rates have been adopted to provide reduced rates for low usage customers while providing a price signal to encourage higher use customers to conserve energy. For example, once a customer usage exceeds the energy consumption allowed in the initial block over a given period of time (typically one month), than this customer will be charged a higher rate for all additional energy consumed within that time period.

While AMI may not be required for adopting limited portions of some of these conservation rates, it is a critical portion of the enabling infrastructure to implement robust conservation rates as:

1) Pilots and program experience demonstrate that there is significantly more response when the rate programs are combined with supporting technologies such as in-home displays and controls;
2) Smart meters enable more flexible and customizable rate designs and programs since pricing parameters (such as period definitions) can be updated remotely and varied by customer type, location and preferences (or options selected. Flexibility and customization enhances the customer acceptance of and participation the rates and programs;
3) Time-of-use and dynamic pricing (CPP and CPR) rates require time-differentiated metering (that is, the ability to collect energy consumption and demand data for specific time intervals); and
4) Many manufacturers and third parties are developing controls, programs, and appliances that link to smart meters to provide households with better management of their energy, demand, and energy bills. The AMI infrastructure provides a platform that allows innovators to develop methods and offerings that provide customers with greater flexibility and management of the demand and energy usage, and energy costs. The addition of these 3rd party offerings can further improve the savings achieved through AMI future programs.

Pre Payment

Electricity payment option coupled with a prepayment meter or other enabling technology that only supplies energy to customers equal to the prepaid amount purchased by the customer. This option may involve working with a third party to sell the prepaid cards, but this is not a requirement for implementing pre-pay rates.

Load Control[6] (LC)

Load control (LC) programs are designed to reduce electric loads during capacity constrained periods by sending signals to customers and/or their equipment to either cease operation or reduce power usage. LC often involves the use of switches on specific end-use loads or appliances that may be activated by the utility upon utility need for load reduction. The need for load reduction (event) may be driven by either reliability or market price considerations. Load control programs typically include:

- Automatic switching off or cycling of certain appliances or loads during the events;
- An option for the customer to over-ride the utility load control signals based upon the customer's needs and preferences (there may be a cost or no credit for exercising the over-ride option); and
- Provide incentive for participating in the program (e.g. a lower rate, a payment per event, or a credit per month when the utility may use the load control events).

The most common load control programs in the residential sector control water heaters and air-conditioners. These programs typically allow the utility to switch the appliance(s) off for a defined period of time during load control events. There are many variations of these programs.

Supporting Technologies

Supporting technologies such as in-home displays, smart thermostats, and smart appliances help customers understand and respond to conservation rates and load control events. Programs utilizing supporting technologies to provide customers with information about usage and costs, and automating the control of appliances show greater savings. In fact, pilots in California, Ontario, Illinois, and New Jersey consistently show that supporting technologies increase demand savings by approximately 50 percent.

In-Home Displays (IHD)

In-home displays (IHD) allow customers to view electricity consumption and costs in real-time. IHDs display total usage and costs to-date for the month, as well current usage. Some IHDs provide additional functionality such as displaying real-time prices and can be used to support dynamic pricing programs Utilities often deploy these devices to enable customers to better manage their energy costs and encourage customer to respond to conservation rates.

For example, Hydro One (Ontario) 30,000 IHD deployment used a Blue Line Innovations PowerCost MonitorTM similar to the one depicted in Figure 2: Hydro One's In-Home Display. These devices provide customers with information on electricity consumption and energy

[6]Load control, as used in this report, refers to programs and tariffs where the utility directly controls appliances or other customer loads. These utility programs and tariffs provide customers with an incentive to allow the utility to reduce usage of selected appliances or loads during peak periods.

prices. Similarly, The Energy Detective manufactured by Energy, Inc. operates with Google's Powermeter software to track energy without a smart meter (TED, 2010).

Figure 2: Hydro One's In-Home Display

Source: Blue Line Innovations, 2010

Ameren's Power Smart Pricing (PSP) pilot used a PriceLight (a small orb that glows different colors based on the current price of electricity) for about 100 of its participating customers. Figure 3: Ameren's PriceLight In-Home Display depicts a similar device which Ameren found to improve customer response to the dynamic prices (Ameren, 2010).

Figure 3: Ameren's PriceLight In-Home Display

Source: Ameren, 2006

Smart Thermostats

Smart thermostats to receive signals from the utility during peak periods and help customers reduce load by adjusting temperature settings during these periods. Some smart thermostats also allow the customer to program settings and override utility signals if they choose. Ameren, for example, deployed smart thermostats as part of its Residential TOU Pilot Study and found them to help customers reduce load during peak periods.

Figure 4 depicts a smart thermostat deployed by Ameren.

Figure 4: Ameren's Smart Thermostat

Source: PSP, 2009

Smart Appliances

Smart appliances have the ability to receive signals from the utility to reduce load or delay start times as shown in Figure 5: General Electric's Demand Response Enabled Smart Appliances. For example, smart dryers can delay start cycles until off peak times. Other appliances such as the water heater can modify temperature settings during high rates such as General Electric's Demand Response Enabled Smart Appliances. These appliances typically communicate with the smart meter over a home area network. General Electric is currently testing load control enabled communicating appliances which can receive price signals and shift demand to off-peak periods. Other vendors are also developing intelligence into appliances that will rely on communicating with a smart meter.

Figure 5: General Electric's Demand Response Enabled Smart Appliances

Source: GE, 2010

Experience from Other Utilities and Programs

This section summarizes results and lessons learned from relevant utility pilots and programs. As mentioned in the *Methodology* section, NCI performed both secondary and primary research of selected utility AMI programs. NCI interviewed five utilities, listed in Table 2: Rationale for Selected Utility Interviews, which had highly relevant pilot and program results. Various regional and programmatic characteristics made these utilities particularly relevant to FortisBC and this study (see Table 2: Rationale for Selected Utility Interviews). The table in *Attachment 2: Utility Research Table* section contains the complete list of utility programs researched.

Table 2: Rationale for Selected Utility Interviews

Utility/Location	Key Pilots/Programs	Relevant Characteristics
Ameren/Illinois	Smart Meter Deployment; Power Smart Pricing program	High penetration of electric space heating; summer peaking; real-time pricing; behavioral based research; residential customer
Avista/Idaho	Demand Response Pilot	Low electric rates; winter peaking; high penetration of electric space heating
BC Hydro/British Columbia	Conservation Research Initiative; Smart Metering and Infrastructure Program	Geographic proximity; some demographic similarities; winter peaking
Hydro One/Ontario	IHD Program Deployment; Time-of-Use Pricing/IHD Pilot Project	Low energy prices; rural location; penetration of electric space heating; low residential rates
PG&E/California	Smart Meter and SmartRate Program; ADRS; Ancillary Services Pilot	Experience with AMI; multiple DR and pricing programs, publicly available results

Secondary Research

This section summarizes results and findings from secondary research including results from meta-studies and from individual utility pilots and programs.

Key Meta-Reviews

Several organizations have completed meta-reviews (i.e. reviews of multiple similar utility programs and pilots) to identify common trends, savings estimates, and drivers of differences where the program or pilots had different results. The estimates of energy and demand savings that could be realized by FortisBC's customers reported later in this report were based on a synthesis of the results from both the utility pilot programs completed specifically for this effort

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and the meta-studies' findings. Table 3: Summary of Secondary Research Findings from Relevant Studies summarizes the key findings from the meta-studies. Additional conclusions

from selected meta-reviews that were used to support the development develop estimates for specific program types are referenced in later sections.

Table 3: Summary of Secondary Research Findings from Relevant Studies

Study	Key Findings	Source
Quantifying the Benefits Of Dynamic Pricing In the Mass Market	• Of the 13 pilots reviewed, CPP programs supported with supporting technologies resulted in the largest reductions in load (15%-50% peak demand shifting) • Implementing dynamic pricing with enabling technologies is more effective than implementing these independently	(Edison Electric Institute, 2008)
Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities	• Analysis of 57 programs providing usage feedback in North America with feedback found savings ranged from 4% to 12% • Real-time feedback programs resulted in average savings of 9% • Accounting for non-participants, real-time feedback (IHD) could provide4% savings for the residential sector	(American Council for an Energy Efficient Economy, 2010
The Impact Of Informational Feedback On Energy Consumption—A Survey Of The Experimental Evidence	• IHD can improve annual energy savings by an average of 7% without dynamic pricing; • IHDs combined with prepayment results in average annual energy savings of 14%	(Faruqui, 2009)
A National Assessment of Demand Response Potential	• Demand response has the potential to reduce 4%-20% of U.S. peak demand by 2019 (dependant on customer participation scenarios)	(FERC, 2009)
Household Response To Dynamic Pricing Of Electricity—A Survey Of The Experimental Evidence	• TOU shifts peak demand by 3%-6% • CPP tariffs shift peak demand by 13%-20% or 27%-44% when combined with enabling technologies	(The Brattle Group, 2009)
Rethinking Prices: The Changing Architecture of Demand Response in America	• Sufficient price differentials between peak and off-peak rates are needed to ensure customers reduce peak demand	(PUF, 2010)
California Statewide Pricing Pilot (CA SPP)	• Fixed CPP rates shifted peak energy on critical days between 7.6-15.8% depending on the climate zone	(CRA, 2005)

Results Reported by Utility Pilots/Programs

In addition to the meta-reviews, summarized above, NCI reviewed evaluations of specific utility pilots or programs. The pilots and programs reviewed were selected based upon relevance to Fortis as well as the availability of a rigorous evaluation of the program impacts. Table 4 and Table 5 summarize the conservation and demand savings reported by utility programs or pilots respectively. Conservation benefits reduce average annual energy savings, while demand savings focus on reductions during periods of peak demand. There are some caveats and limitations to the results from these evaluations, including the following:

- Savings depend on specifics of the rate design. For example, the savings are affected by the price for on-peak usage compared to the price for off-peak consumption as well as by the length of the on-peak period and when the on-peak period begins and ends. An on-peak/off-peak price differential of 4 will produce larger peak demand savings than a differential of 2 (see graphs in the *Elasticities* section, below). We summarized the savings ranges provided in the respective evaluation reports without analyzing the details of the rate structure, and selected conservative values for estimating energy and load reductions.
- In many cases, only conservation or demand impacts were reported, based on the objectives and evaluation of the program. For example, many of the IHD programs only report energy savings. Associated load reductions were estimated either from evaluations that reported load and energy savings or by assuming that load savings were proportional to energy savings (i.e. if a household reduces their annual energy use by 5 percent, they also reduce their peak demand by 5 percent).
- The evaluations of pilots and programs have two common limitations:
    - ***Self-selection bias*** – customers who are most likely to respond to load control, dynamic prices and conservation rates will be the ones that will volunteer to participate in the pilot programs or for optional programs. Only a fraction of customers will participate in any given program. Very few evaluations control for this self-selection bias or collect data that allows one to forecast participation rates. The ACEEE meta-analysis indicates that participation rates may be on the order of 65% to 85% for opt-out programs and on the order of 5% to 10% for opt-in programs. We used the results of the ACEEE meta-analysis as best available data for developing the range of participation forecasts.
    - ***Limited data on persistence*** – there is limited evaluations of the response over multiple years. As discussed below, there appears to be some small reduction in response to TOU and dynamic prices after the first year. We assumed that the savings would decrease by 10% after the first year to provide a conservative estimate.

At the same time, some technology and market trends may result in enhanced response to conservation rates and load control programs: many companies including CISCO, Microsoft, Google, and numerous new entrants, with generous venture capital funding are developing and marketing applications and services to households to enable them to better control their energy usage. Evaluations of pilot programs show that technology enables a more robust and persistent response to conservation rates and load control programs. The offerings of these non-utility, innovators should enhance the response to conservation rates and load control programs.

Table 4: Program Impacts on Annual Energy Savings

Program	Program/Pilot	Benefits	Source
Supporting Technology	Time-of-Use Pricing Pilot Project	Added savings from IHD was 3.4% for summer energy in addition to the 3.3% energy savings from TOU.	(Hydro One, 2008)
	BC and Newfoundland real-time feedback pilot	The 2005-2007 IHD pilot resulted in 3%-18% average decrease in electricity	(CEATI, 2008)
	ACEEE meta-analysis of feedback	Real-time feedback resulted in 5.4% savings	(ACEEE, 2010)
TOU	Ontario Energy Board Smart Price Pilot	6.0% conservation effect	(IBM and eMeter, 2007)
	Time-of-Use Pricing Pilot Project	3.3% energy savings during the summer months	(Hydro One, 2008)
	BC Hydro Conservation Research Initiative (CRI)	Reductions in energy use of 11.5% and 11.1% during peak hours for years 1 and 2, respectively, annual energy savings were 7.9% and 5.5% for years 1 and 2.	(LeClair. 2010)
	Ameren Power Smart Pricing Program	1.5% overall annual energy savings and 6% savings during summer season	(Ameren, 2008)
	Newmarket Hydro TOU Pricing Program	2.8% reduction in peak period energy usage with no significant annual savings, 63% participation in the opt-out TOUprogram	(Newmarket, 2010) Newmarket, 2008)
Pre-pay (w/ pre-pay card and display unit)	Woodstock Hydro's Pay-As-You-Go	15-20% reduction on a customer's average annual consumption with supporting technology	(Woodstock Hydro, 2004)
	Salt River Project M-Power Price Plan	12% reduction on a customer's average annual energy consumption with supporting technology	(SRP, 2009)
CPR	Ontario Energy Board Smart Price Pilot	7.4% conservation effect during entire program	(IBM and eMeter, 2007)
	Ontario Energy Board Smart Price Pilot	4.7% conservation effect during entire program	(IBM and eMeter, 2007)

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The results from the Newmarket Hydro's TOU Pricing program suggest an average savings during peak periods of 2.8% with minimal energy savings over the entire year. The Newmarket program was mandatory and therefore, doesn't suffer from self-selection bias. Most of the other TOU pilot programs have self-selection. BC Hydro's TOU showed significantly higher peak reductions of more than 11 percent. The BC Hydro pilot was completed with volunteers. The Hydro One pilot, with a 3.7% peak savings was also completed with volunteers. Hydro One enrolled only 13% of the customers solicited.

Table 5: Program Impacts on Peak Demands summarizes the effect on peak demand by utility programs or pilots. These peak demand shifting benefits typically estimate the average energy demand a customer shifts from peak to off-peak periods.

Table 5: Program Impacts on Peak Demands

Program	Program/Pilot	Benefits	Source
Supporting Technology	Time-of-Use Pricing Pilot Project	5.5%-8.5% combined TOU and IHD impact (1.8%-5.6% incremental impact from IHDs during summer peak periods)	(Hydro One, 2008)
	Residential TOU Pilot Study	Participants with CPP + smart thermostats roughly doubled peak load shifting compared to effect of CPP alone	(Ameren, 2006)
	Meta-Analysis of 36 programs and pilots	Real-time feedback from IHD saves 5.4% more than providing customized information and feedback on the bills	(ACEEE, 2010)
LC (w/TOU)	California Automated DR System Pilot	GoodWatts device: 43% peak reduction during 11 summer CPP days; 27% peak reduction during TOU non-CPP days	(RMI, 2006)
TOU	Conservation Research Initiative (CRI)	11.5% reduction in peak energy use during year one of program with smart meter technology (7.6% during winter peak)	(BC Hydro, 2009)
	Time-of-Use Pricing Pilot Project	3.7% load shifting during the summer months	(Hydro One, 2008)
	Newmarket Hydro TOU Pricing Pilot	2.8% reduction in on-peak energy usage for TOU only participants	(Newmarket, 2010)
	Puget Sound Energy's TOU Pilot	5% average reduction in peak energy during 15 months of the program	(Faruqui, 2003)
CPR	Ontario Energy Board Smart Price Pilot	17.5% reduction during critical peak hours (~4 hrs); 8.5% reduction during entire peak (~6 hrs)	(IBM and eMeter, 2007)

CPP	PG&E 2008 SmartRate Program	CPP SmartRate--22.6% peak reduction	(Freeman Sullivan & Co., 2009)
	Ontario Energy Board Smart Price Pilot	25.4% reduction during critical peak hours (~4 hrs); 11.9% reduction during entire peak (~6 hrs)	(IBM and eMeter, 2007)
CPP and TOU	PSE&G myPower Sense and myPower Connection	TOU + CPP—12% peak reduction; TOU + CPP + smart thermostat—18% peak reduction	(PSE&G and SBC, 2007)

Experience from Winter Peaking Utilities

Savings from conservation demand management programs may vary depending on the peak season. For example, some customers may be more willing to reduce their cooling usage during the summer in response to peak prices than they would be to reduce their space heating usage during winter months in response to peak prices. The ACEEE meta-analysis notes that short duration pilots show larger savings than long duration pilots due, in part, to the failure of shorter duration pilots to capture seasonal variations (ACEEE 2010).

Avista, found customers from its demand response pilot to be less responsive during peaking events that took place during the winter months than those that occurred during the summer months.

Puget Sound Energy (PSE), a utility located in the Pacific Northwest, also has experience implementing a TOU pilot, but was less successful due to its small rate differential between peak and off-peak periods. Like FortisBC, PSE's peak period occurs during the winter and hydro resources supply a majority of its electricity. PSE set the peak period price just 15% higher than the standard rate and the off-peak price 15% lower than the standard rate (1.3:1 ratio) to reflect its hydro-based system in the Northwest (Faruqui, 2003). Such small rate differentials did not motivate customers to make behavioral changes and shift their peak demand as they only received a small amount of savings.

BC Hydro has similar peak periods similar to those of Fortis, given its geographic proximity. Based on results from the first year of the Conservation Research Initiative (CRI), BC Hydro reduced peak period energy usage by 7.6% on average during the winter months of December, January, and February. This TOU conservation impact is larger than the TOU conservation impact observed in many of the other pilots. This suggests that, at least for energy, other factors than the season of the utility peak may be more important drivers of the observed savings.

Experience from Utilities with Results on Both Peak Shifting and Conservation

While many utility pilots only reported on savings from either peak shifting or conservation, some pilots reported both. These pilots include BC Hydro's CRI, Hydro One's TOU Pricing Pilot, and Ontario Energy Board's (OEB) Smart Price Pilot. These results are summarized in Table 6: Peak Period and Annual/Energy Savings for Canadian TOU Programs.

Table 6: Peak Period and Annual/Energy Savings for Canadian TOU Programs

Utility	Program	Critical Peak	Peak	Seasonal/Annual Energy
BC Hydro	TOU	NA	11%	5.5%
	TOU & CPP	21%		
Ontario Energy Board	TOU	5.7%	2.4%	6.0%
	TOU & CPP	25.4%	11.9%	4.7%
	TOU & CPR	17.5%	8.5%	7.4%
Hydro One	TOU	--	3.7%	3.3%
	TOU & IHD	--	8.5%	7.6%
New Market Hydro	TOU (Mandatory)	--	2.8%	0.66%

These results show that:

- Peak savings range from 4% to 11% per participant
- Annual savings range from 3% to 7.5% per participating customer
- CPP or CPR increase peak period savings to the range of 17% to 25% per participant
- Per customer savings for a mandatory program (Newmarket) may be one-fifth of the savings of the savings observed for volunteer participants, suggesting that approximately 20% of customers will respond to mandatory tariffs.

Inclining Block Rates

BC Hydro, in their application for inclining block used a price elasticity estimate of -0.1 as a conservative assumption (Orans, 2008). BC Hydro is commencing an evaluation of its inclining block rate program in the fall of 2010. This appears to be the first evaluation of the the inclining block rates for electricity.

Customers take a a while learn, understand, and adopt to new rate structures. Changing the default rate structures too frequently could create customer confusion and increases marketing costs. NCI did not find empirical evidence supporting the conservation effect of inclining block rates.[7] If FortisBC plans to implement TOU rates with the next 3 to 5 years, the Company may want to avoid having to transition customers to different deafult rate structures wihin a period of several years as may cause customer confusion.

[7] Commonwealth Edison's Smart Meter Pilot is in the process of deploying its smart meters which will test incline block rates, but results have yet to be published (PUF, 2010), BC Hydro is just initiating an evaluation of their inclining block rate in the fall of 2010.

Primary Research

This section summarizes results and findings from the utility interviews. Since NCI conducted both primary and secondary research for these utilities, some information from secondary sources is also included in this section for background.

Overview of Utility Interviews

NCI interviewed the five utilities that were previously identified in Table 2: Rationale for Selected Utility Interviews. The interviews were conducted to develop insights from their pilots and programs and lessons learned from a range of utilities with different types of AMI future program experience. These utilities also have a variety of experience with different innovative pricing programs (e.g., critical peak pricing and critical peak rebates), some programs with in-home displays, and various implementations of load control. *Attachment 1: Primary Research* section provides detailed notes from these interviews which have been paraphrased to focus on relevant content for this study.

In Table 7: Ameren Summary, we summarize the relevant program, benefits, and cost information gathered from the interview with Ameren and supplemental research.

Table 7: Ameren Summary

Ameren—Illinois	
Overview of Relevant Programs	• <u>Smart Meter Deployment</u>: began in 2006 and aims to improve customer service and reduce O&M costs with its installation of 1.1 million gas and electric smart meters from Landis+Gyr • <u>Power Smart Pricing (PSP) program:</u> started in 2007 and uses a low technology approach (e.g. incremental meters) to implement voluntary real-time pricing by notifying customers of a critical peak pricing period one day in advance via email or with an automated phone call
Benefits and Costs of Program	• PSP resulted in: a 6% reduction in average energy use during the peak summer season and 1.5% annual average reduction; an overall elasticity of -4.3% for the 2008 summer season; and 7.7% (9.1% including conservation) average annualized bill savings on customer bills compared to flat-rate charges; • Since Power Smart Pricing launched in early 2007, participants have saved an average of 17% compared with what they would have paid on the standard fixed rate (based on billing results for May 2007 through Sept. 2009)
Program Administration Activities and Costs	• Costs of the PSP program include incremental cost of metering to collect hourly usage data, additional utility expenses for software and data processing systems, and the program administrator and evaluation contracts • CNT Energy is responsible for all the marketing and customer education associated with the PSP program
Programmatic Insights	• Establish payment for vendors to correspond with verification of accurate meter reading and full system functionality rather than just meter installations. • Begin communicating early in the deployment with and helping transition employees whose jobs may be at risk with the technology automation. • Set realistic expectations for customers and involve local community partners and

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	municipalities to improve customer acceptance and satisfaction.
Sources: Ameren, 2010. Personal communication. January 2010. Ameren, 2006. "Automated Meter Reading." Ameren Services. Web. 18 Sept. 2010. <http://www.ameren.com/Residential/ADC_AMR.asp>. CNT Energy and Summit Blue, "Residential Real-Time Pricing Program Achieves Savings for Utility and Customers", Draft Paper, November 2009. Summit Blue Consulting, "Power Smart Pricing 2008 Annual Report," March 31 2009. Voytas, Rick. "AmerenUE Critical Peak Pricing Pilot", presented at U.S. Demand Response Research Center Conference, Berkeley, CA., June 2006	

Table 8: Avista Summary summarizes the relevant program, benefits, and cost information gathered from the interview with Avista and supplemental research.

Table 8: Avista Summary

Avista—Idaho	
Overview of Relevant Programs	• Demand Response Pilot—spanning from July 2007-December 2009 this pilot tested the effectiveness of smart thermostats and direct control unit (DCU) switches on customer devices (e.g. water heaters, compressors, heat pumps, and AC) for over 70 residential customers.
Benefits and Costs of Program	• The pilot did not track enough data to measure the average energy reduction, but Avista estimated savings to be consistent with other pilots of this nature. • Customers tended to be less responsive to peak events during the winter when compared with the summer.
Program Administration Activities and Costs	• The pilot program cost US$123,000 for 2 years which included customer incentives, equipment costs, hosting fee for the vendors (~US$1,000/month), and marketing costs through an advertisement agency (~US$2,000). • Avista paid customers with a DCU about $10/ peak month for participating during peak events. Avista provided no cash incentives to use the smart thermostats, but these customers did receive a free thermostat.
Programmatic Insights	• Implementing price signals (e.g. dynamic rates) with the smart thermostats would have likely improved ongoing customer participation and savings. The lack of dynamic pricing meant customers had less incentive to reduce their load and participate during peak events. • Customers tended to be very enthusiastic about the smart thermostats and energy management capability at the start of the pilot, but after a few months the novelty for customers seemed to wear-off and savings dropped off. Battery failures were an issue. Decreasing savings were attributed largely to the lack of pricing signals. • Don't begin marketing the program to customers until the equipment has been tested and is ready to be deployed.
Sources: Avista, 2010. Personal communication. February 2010. Avista, 2009. "2009 Electric Integrated Resource Plan," Avista Utilities, August 2009.	

Table 9: BC Hydro Summary summarizes the relevant program, benefits, and cost information gathered from the interview with BC Hydro and supplemental research. BC Hydro's conservation research initiative (CRI) was designed to test residential customers' responses to alternative conservation rates. Because of the demographic and climatic similarities between BC Hydro's and FortisBC's service areas, their results are likely to be particularly applicable to FortisBC.

Table 9: BC Hydro Summary

BC Hydro—British Columbia	
Overview of Relevant Programs	• Smart Metering and Infrastructure (SMI) Program: aims to improve BC Hydro's O&M electric services and enable innovative conservation rate structures and customer energy management with the installation of approximately 1.8 million smart meters and their associated IT systems • Conservation Research Initiative (CRI): aims to test the effectiveness time-of-use (TOU) rates and smart meters at shifting and conserving peak load for roughly 2,000 residential customers in British Columbia
Benefits and Costs of Program	• TOU participants reduced winter peak period energy usage by 11.5% in year 1 and 11.1% in year 2, while annual energy savings was 7.9% in year 1, and 5.5% in year 2. • CPP participants provided an additional 10% reduction during peaks. • Direct load control participants peak energy consumption savings were less than 1%
Program Administration Activities and Costs	• Load control devices were difficult to implement due to installation costs and challenges; controllable thermostats are likely an easier alternative to deploy
Programmatic Insights	• When implementing alternative pricing schemes, try to choose a design that is clear and easy for customers to understand. • A considerable amount of customer support and services are required to implement a smart meter and/or TOU program.
Sources: BC Hydro, 2009. "Conservation Research Initiative." BC Hydro. Web. 18 January 2010. <http://www.bchydro.com/powersmart/residential/conservation_research_initiative.html> BC Hydro, "2009 Electricity Conservation Report", November 2009. BC Hydro's "Conservation Research Initiative", paper presented at Vaasa ETT Exchange Roundtable, by Donna LeClair, Chief Technology Officer, May 26, 2010. BC Hydro, 2010. Personal communication. January 2010.	

Table 10: Hydro One Summary summarizes the relevant program, benefits, and cost information gathered from the interview with Hydro One and supplemental research.

Table 10: Hydro One Summary

Hydro One—Ontario	
Overview of Relevant Programs	• 2005 IHD Pilot: tested effectiveness of real-time feedback on energy consumption with 500 residential IHDs • 2007 Time-of-Use Pricing/IHD Pilot Project: tested impact of TOU combined with IHDs on 486 smart metered customer volunteers • 2006-2007 IHD Program Deployment: this $5 million voluntary project distributed 30,000 IHDs to residential customers
Benefits and Costs of Program	• The IHD pilot of 500 reduced energy by 6.5% on average while the IHD deployment was 5.2%; when IHD was combined with TOU, the savings were slightly higher at 7.6% (4.3% from IHD and 3.3% from TOU) • At the start of the IHD deployment, Hydro One paid a third party (Blue Line Innovations) roughly $150 per IHD (included hardware, marketing and shipping); most customers self-installed the devices
Program Administration Activities and Costs	• The two pilots tried to minimize the amount of customer education and marketing to isolate the impact of just the technology • Customer education and marketing cost about $25-$50 per customer for the 30,000 IHD deployment which included radio, newspaper adds, customer calls, and informational instructions mailed with the devices
Programmatic Insights	• Highlighting electric heating load of homes with the IHD may have helped encourage conservation for the 2005 IHD pilot as many of the customers with electric space heating were less responsive to real time feedback (the IHD reduced load by 1.2% in these houses compared to the 6.7% average • Real-time feedback of energy consumption is effective in promoting conservation even without real-time pricing. • IHDs with two-way communication that can be remotely updated by the utility or AMI system are often more effective in promoting conservation as customers rarely program these devices on their own (e.g. programming updates to TOU periods); also IHDs powered by batteries were less reliable.
Sources: Hydro One, 2010. Personal communication. January 2010. Hydro One, "Time-of-Use Pricing Pilot Project Results", EB-2007-0086, May 2008. Hydro One, "The Impact of Real-Time Feedback on Residential Electricity Consumption: The Hydro One Pilot", March 2006.	

Table 11: PG&E Program Overview summarizes the relevant program, benefits, and cost information gathered from the interview with PG&E and supplemental research.

Table 11: PG&E Program Overview

Pacific Gas and Electric (PG&E)—California	
Overview of Relevant Programs	• Smart Meter and SmartRate™: PG&E is spending US$2.2 billion dollars to install ~10 million smart meters (54% electric and 46% gas) which will enable voluntary critical peak pricing (SmartRate™) for all customers. Since 2006, PG&E has installed 4.6 million meters and plans to finish deployment by 2012. • Ancillary Services Pilot: During the summer of 2009, worked with LBNL to test air conditioning automated demand response for 2,000 customers • Automated Demand Response System Pilot (ADRS)—In 2005 PG&E, along with other California utilities, implemented a residential-scale automated demand response technology (thermostats) for customers with critical peak pricing
Benefits and Costs of Program	• The SmartRate™ program rewards customers with a credit of nearly 3 cents (US$) for each kWh used outside of critical peak load periods (i.e. the hottest summer afternoons); customer response to the program has been positive
Program Administration Activities and Costs	• Total costs of AS Pilot were ~US$1.4 million (roughly 20% for administration, 11% for customer recruiting and education, 35% for installation/other services, and the remainder for hardware, reporting, customer surveying costs)
Programmatic Insights	• Keep the program simple and implement a pricing structure that is straightforward and clear, to help customers to understand the benefit proposition. • Too much information can be confusing for customers, so sending concise and clear education material helps reduce questions and increase participation. • Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements.
Sources: Charles River Associates. "Impact Evaluation of the California Statewide Pricing Pilot", 2005. Rocky Mountain Institute. "Automated Demand Response System Pilot: Final Report", March 2006. Freeman, Sullivan & Co. "2009 Pacific Gas and Electric Company SmartAC Ancillary Services Pilot", December 2009. PG&E, 2010. Personal Communication. January 15th, 2010.	

Lessons Learned from Utility Interviews

The interviews provided insights and lessons learned from the utility pilots and programs. While the interview discussions and questions differed slightly depending on the program experience for each utility, the lessons learned can be grouped into several key drivers of program savings: peaking period; customer persistence and satisfaction; program design.

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Table 12: Summary of Lessons Learned from Interviews summarizes the key lessons learned grouped by these categories. *Attachment 1: Primary Research* section provides detailed notes from the interviews which have been paraphrased to focus on relevant content for this study.

Table 12: Summary of Lessons Learned from Interviews

Key Driver of Program Savings	Lessons Learned
Peaking Period	• If technologically possible, provide energy demand information at the customer appliance level in order to inform customers on which major appliances to adjust during peak periods, e.g. electric space heating. (Hydro One, 2010) • Provide residential customers with higher price signals during non-discretionary demand periods in the winter as customers tend to be less responsive to peak events during winter peak periods (morning and evening hours) when compared with summer peak afternoon hours (Avista, 2010)
Customer Persistence and Satisfaction	• Minimize customer activities required to operate and maintain IHDs (e.g. installation, programming updates, and replacing batteries) with automated and utility controlled technology where possible (Hydro One, 2010; Avista, 2010) • Implement price signals with enabling technologies (e.g. IHD) to incentivize ongoing customer participation (Avista, 2010). Without price signals, savings from IHD decay quickly (Avista, 2010)
Program Design	• For a voluntary program, involve local community partners and municipalities to encourage customer awareness and adoption (Ameren, 2010) • Design the program to be simple and implement a pricing structure that are clear to help customers understand the benefits of participating (BC Hydro, 2010) • Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements (PG&E) • Keep program informational materials concise and easy to understand to reduce customer questions and additional customer communication costs (PG&E)
Program Implementation	• Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements (PG&E) • Ensure meters operate and are configured correctly during rollout (BC Hydro)
Sources: Ameren, 2010. Personal communication. January 2010. Avista, 2010. Personal communication. February 2010. BC Hydro, 2010. Personal communication. January 2010. Hydro One, 2010. Personal communication. January 2010. PG&E, 2010. Personal Communication. January 15th, 2010.	

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Key Issues

NCI identified several key issues which influence the overall impact of AMI Future Programs including elasticity, persistence of customer savings, energy payback, peak period, and the interactive effect of multiple programs and supporting technologies.

Elasticity

Elasticity measures the responsiveness of customers to adjust their energy consumption in response to changes in the price of energy. Table 13 summarizes elasticity estimates and measurements from various studies. The savings estimates used from various CDM pilots (see Table 13: Residential Elasticity Estimates from Research) also helps measure this responsiveness and predict customer behavior. Elasticity estimates range from a low -0.02 to a high of -0.184. A number of estimates cluster in the -0.03 to -0.06 range. Based on the findings in these studies NCI recommends FortisBC use an elasticity in the range of -0.03 to -0.06 for TOU programs for its residential sector.

Table 13: Residential Elasticity Estimates from Research

Price Elasticity Research	Source
BC Hydro's 2007 Electric Load Forecast decomposed the conservation impact of rates into rate level-induced and rate design-induced conservation components for its inclining block rates, using an elasticity of -0.05 for the lowest block and -0.1 for the higher tier.	(BC Hydro LTAP, 2008)
Ameren's 2008 PSP program had an overall elasticity for the summer season of -0.043	(PSP Annual Report, 2008)
Newmarket Hydro Time-of-Use Pricing Pilot's average participant price elasticity ranged from -0.02 to -0.05	(NCI, 2008)
PSE&G myPower Sense program TOU + CPP had a -0.085 substitution elasticity; PSE&G myPower Communication program TOU + CPP +Programmable/Communicating thermostat had a -0.137 substitution elasticity	(Edison Electric Institute, 2008)
California SPP's fixed CPP elasticity ranged from -.035 to -.054 for 2003 and 2004 respectively	(CRA, 2005)
BC Hydro TOU pilot estimated elasticity of substitution of -0.06, and price elasticity of -0.187	(Tiedemann, 2008)

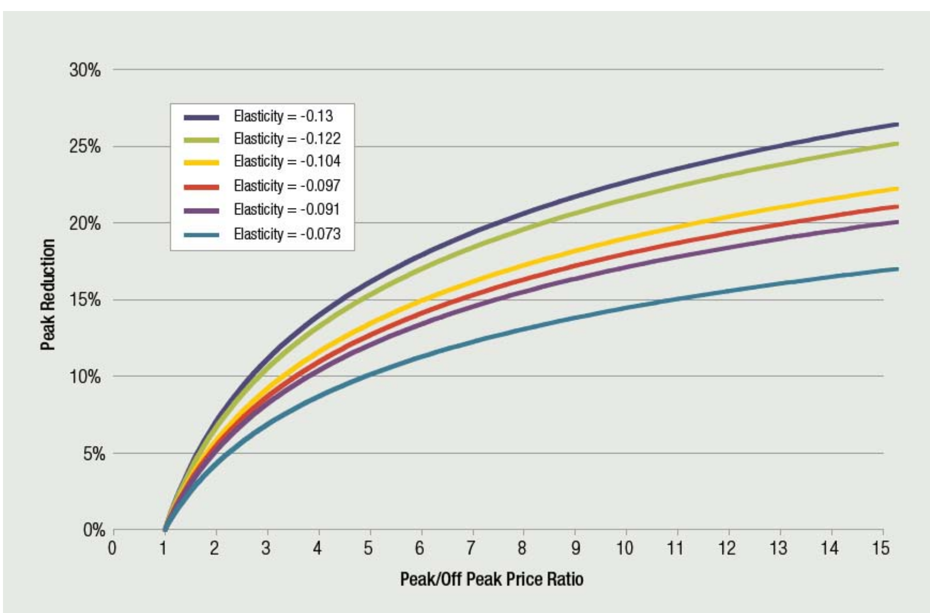
Table 14: BC Hydro's Commercial and Industrial Elasticity Forecast Estimates lists estimates for elasticity of commercial and industrial customers used by BC Hydro in their 2006 and 2007 load forecast. C&I sectors have higher elasticities (-0.1 to -0.2) than the residential sector (roughly -0.05) which suggests C&I industries are more responsive to price changes. For example, during high price periods, industrial customers are more likely to shift demand to off-peak periods in order to reduce costs.

Table 14: BC Hydro's Commercial and Industrial Elasticity Forecast Estimates

Sector	Short-Term Elasticity
Commercial	-0.1
Industrial	-0.2
Source: BC Hydro, "Electric Load Forecast 2006/07 to 2026/27", Market Forecasting, Energy Planning, Customer Care and Conservation.	

Figure 6: Demand Response Peak Reduction of Residential Customers on a CPP Rate with Varying Elasticities shows the relationship between price and peak reduction for varying elasticities. The Brattle Group developed this relationship based on research from multiple pilot projects (PUF, 2010). Figure 6: Demand Response Peak Reduction of Residential Customers on a CPP Rate with Varying Elasticities also highlights the variable impact of residential elasticities ranging from -0.13 to -0.073, which for a 3 to 1 peak/off peak ration results in a 7%-11% peak reduction. Because the CPP entail only a few events during the year with notification, one would expect elasticities for CPP than TOU. We recommend using the lower end of the elasticities in Figure 6: Demand Response Peak Reduction of Residential Customers on a CPP Rate with Varying Elasticities, i.e., -0.73 to -0.91. This value is higher than for TOU, consistent with some the pilots, and is a conservative value.

Figure 6: Demand Response Peak Reduction of Residential Customers on a CPP Rate with Varying Elasticities



Source: PUF, 2010 Note: The Brattle Group used elasticity data from multiple pilots to develop this graph showing the effect of dynamic pricing on customers without enabling technologies.

Persistence of Customer Savings

The limited data on persistence indicates that savings persist from year to year for CPP and CPR rates, particularly when coupled with technology. The ACEEE meta-analysis included 27 feedback studies found that the energy savings persisted as long as the feedback continued. For example, one study in the Netherlands found that the 12% savings from IHD's declined significantly in the year after the IHD's were removed.

The California Statewide Pricing Pilot (SPP) specifically evaluated demand impacts over two years from 2003-2004 (EEI, 2008). The results were that the CPP customers increased their savings slightly in 2004 relative to 2003, while the savings for the TOU customers almost disappeared in 2004. Neither group had supporting technology. The TOU on-peak rate was twice that of the off-peak rate, whereas the CPP rate was five times the off-peak rate. The higher persistence of the CPP rate impact compared to the TOU may be attributable to several factors: the fact that the utility implemented CPP rate for only a few targeted days; the CPP rate had much higher peak/off- peak differential; and the utility directly communicated with the customer on the day before or the day of the critical peak events (EEI, 2008).

The BC Hydro CRI showed peak period reductions of 11.5% in year 1 and 11.1% in year 2, suggesting that peak period reductions persist. The overall savings in the winter months declined from 7.9% reduction in year 1 to 5.5% in year 2. This decline could be a result of multiple factors including weather, economy, or lack of persistence. Overall there is very limited data on persistence of savings. We recommend assuming that there is a 10% decrease in savings following the first year of participation as a conservative assumption.

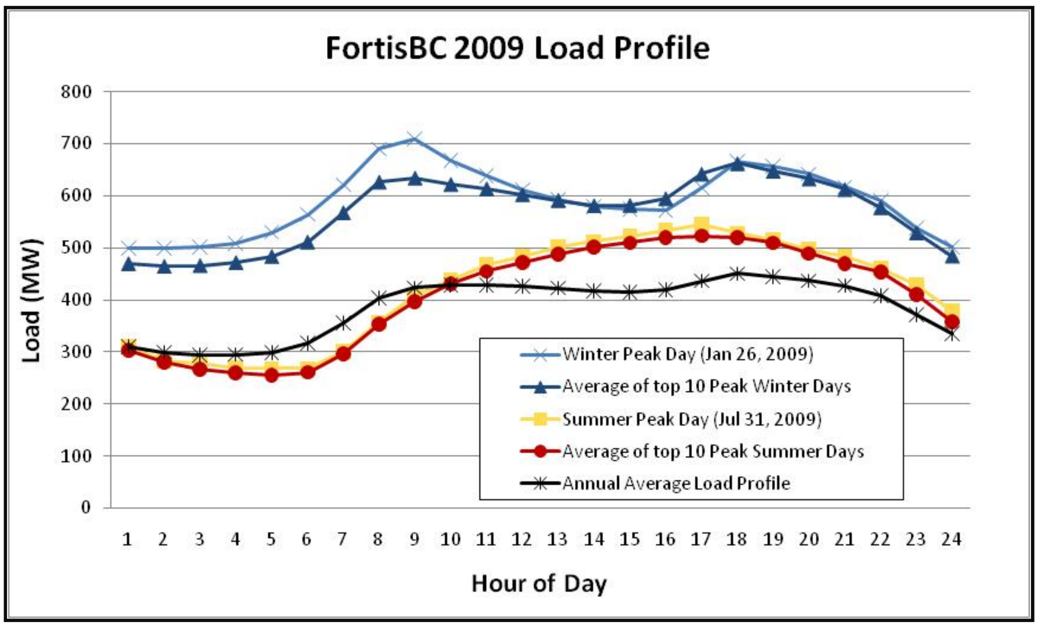
Energy Payback

Energy payback measures the extent to which peak period savings result in increased energy usage during off-peak periods. For example, load control programs generally find that appliances switched off during the peak periods tend to be used more heavily during the non-peak periods. Avista in their load control pilot estimated that peak demand reductions were .33 kW per controlled water heater and 1.5 kW per controlled space heater, yet they observed very little overall conservation effect, and even some increased consumption on the day following the control event (Avista, 2010). The California SPP found increases in off-peak usage for the TOU and CPP tariffs and found no change in total energy use across the entire year (EEI, 2008). Pilots, as summarized in Table 4: Program Impacts on Annual Energy Savings have shown a range of impacts ranging from small increases in overall consumption to annual energy savings of 5-10% overall conservation impact. The pilots with CPP and TOU rates specifically designed to be revenue neutral and with little customer communication tend to show the smallest conservation impacts. The programs (or participant groups) that were coupled with customer education and supporting technology tend to show higher conservation and peak period reductions. For example, the ACEEE meta-analysis of 36 pilots implemented between 1995 and 2010 showed an average savings of 9.2% from real-time feedback (e.g. from IHD's).

Peak Period

Utilities typically design conservation rates that reduce load during peak periods. FortisBC's peak load profile for the summer and winter periods are summarized in Figure 7: FortisBC Load Profiles for Winter/Summer Peak Days and Annual Average in 2009. The top 10 peak winter days in 2009 all occurred during December and January, while the summer top 10 all occurred during July and August. These load profiles suggests that a conservation rate such as CPR would be most effective if it was implemented during winter critical peak days in the evening (e.g. from 5-9pm) and morning hours (e.g. 8-10am). Similarly if CPR was implemented during summer critical peak days it would target reductions in load in the late afternoon hours (e.g. from 3-7pm).

Figure 7: FortisBC Load Profiles for Winter/Summer Peak Days and Annual Average in 2009



Source: FortisBC Load Data, 2010
Note: Of the top 10 winter peaks in 2009, the highest load occurred during the evening period for nine out of the ten days, which suggests the Jan. 26th morning peak may have been an anomaly.

FortisBC's load duration curve in Figure 8: FortisBC Load Duration Curve for Top 100 Hours in 2009 also suggests that using a conservation rate for even a few hours per year could result in significant benefits. Figure 8 shows that peak loads were reached in 2009 during just a few hours of the year. For example, the top 10% (71 MW) of the peak load in 2009 occurred for about 40 hours. Similarly, the top 6% of the peak load (44 MW) in 2009 occurred for fewer than 6 hours.

Figure 8: FortisBC Load Duration Curve for Top 100 Hours in 2009

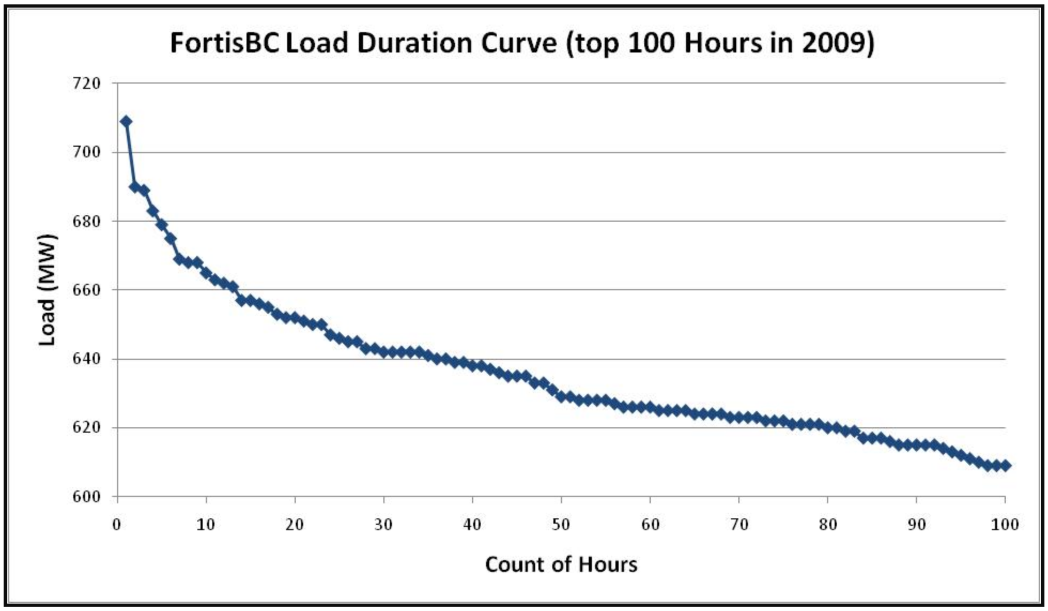


Table 15: Top 10 Hourly Loads in 2009 provides more detail on the time period for the top 10 peak hours in 2009, which all took place during the January and December winter months.

Table 15: Top 10 Hourly Loads in 2009

Date	Hour Ending	Load (MW)	% of 2009 Peak	Difference (MW)
26-Jan-09	9	709	100%	0
26-Jan-09	8	690	97%	19
14-Dec-09	18	689	97%	20
8-Dec-09	18	683	96%	26
14-Dec-09	17	679	96%	30
14-Dec-09	19	675	95%	34
10-Dec-09	18	669	94%	40
26-Jan-09	10	668	94%	41
8-Dec-09	19	668	94%	41
26-Jan-09	18	665	94%	44

Interactive Effects

The evidence indicates that savings increase and are more likely to persist if rates are combined with on-going information, customer feedback, and enabling technology. For example, the Hydro One pilot showed that TOU rates with IHD increased peak savings from 3.7% to 5.5% while energy savings increased from 3.3% to 7.6 %. The California SPP showed that customers with enabling technology (such as smart thermostats) reduced their on-peak usage by from 18% to 27%. The results suggest that:

- Utility communication and marketing is important to remind customers that they can manage their usage; and
- Coupling enabling technology with the rates will increase the peak energy and conservation impacts by roughly 50%.

The pilot programs and experience to date have not focused on the enhanced benefit between these conservation rate/LC programs and the utility's energy efficiency programs. Very few pilots have measured the benefits of market segmentation and targeting customers with the highest likelihood to reduce energy. One evaluation of Ameren's Power Smart Pricing (PSP) did examine the propensity of customers to participate in Ameren's CFL program. They found that PSP customers were five times more likely to participate in the CFL program (Ameren, 2008). Self selection bias may explain some portion of this increased participation, but it also appears that increased awareness of energy consumption enhances participation in other programs.

Program Impact

Energy and Capacity Savings

Based on the research discussed in previous sections of this report, NCI developed estimates of the savings FortisBC might expect to see from potential AMI future programs. Because of the range of results from the various studies reviewed and the uncertainties, conservative savings values were recommended. The recommended savings impacts by type of program are summarized in Table 16: Per Participant Savings for Possible AMI Future Programs.

Table 16: Per Participant Savings for Possible AMI Future Programs

Program Type		Peak	Energy	Source
Conservation Rates	**TOU**	11%	5.5%	BC Hydro CRI[8]
	CPP/CPR	10%	0	
	Inclining	1.8%	1.8%	BC Hydro CRI[9]
Pre-Pay		5.8%*	11.7%	Woodstock Hydro 2004[10]
Load Control		13.3%	0	FERC 2009
In-Home Displays		2.7%	5.4%	ACEEE 2010

* Assume that the peak period savings are half of the annual savings

Impacts with Supporting Technology

The supporting technology bundle is assumed to include an in-home display (IHD) and either a programmable, communicating thermostat (PCT) or up to 4 load control switches/smart appliances. The impact of the supporting technology was estimated to increase savings by 50% over the savings estimates summarized in Table 16: Per Participant Savings for Possible AMI Future Programs. This 50% increase in savings is consistent with the data and assumptions in the "*US National Demand Response Assessment*" (FERC 2009). This assumption is conservatively consistent with the results from multiple studies reviewed including:

- Hydro One found that households with TOU and IHDs showed more than twice the savings in both energy and demand compared to TOU participants without TOU.
- The ACEEE meta-analysis found that programs focused on peak load shifting provided an average energy savings of 3%, while those focused on both peak and energy have provided energy savings of 10%.

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[8] B,C, Hydro, 2010 "Conservation Rate Initiative, BC Hydro Website

[9] B.C, Hydro 2008, "2008 Residential Inclininy Block Application," February, 2008

[10] Average of range from Woodstock Hydro, 2004. "Pay-As-You-Go-Power: Treating Electricity as a Commodity," Ken Quesnelle (Vice-President), January 20, 2004

- Woodstock Hydro found that supporting technology increase savings from pre-pay meters from an average of 11.77% to 15% to 20%.
- Public Service Electric & Gas "myPower" pilot showed 50% higher peak savings for customers with supporting technology (18% vs. 12%) for their CPP/TOU rate.

Conservation Rates

TOU

We recommend using the BC Hydro CRI results as the impact from participating customers. BC Hydro is most similar to FortisBC in terms of climate, prices and demographics. As discussed below, these need to be adjusted for number of participation rates. We recommend assuming that 20% to 30% response rate is consistent with analyses that show that 20% to 30% provide most of the response to mandatory TOU programs, and make the voluntary programs (e.g. BC Hydro, Hydro One) consistent with the mandatory programs (Newmarket Hydro).

- The Newmarket program is the only program reviewed where there was no self-selection bias and results included multiple years. The evaluation results for this program for the very aware segment of customers are consistent with the observed responses for the BC Hydro CRI voluntary respondents;
- The ACEEE Meta-Analysis indicates that volunteers are approximately 5% of the customer population; and
- Several studies indicate that elasticity estimates should apply to the total bill. If the TOU rate is revenue neutral, then conservation effects should be minimal.

For peak demands, the most relevant TOU studies are the Newmarket and BC Hydro CRI programs: The Newmarket evaluation shows a peak demand savings for TOU rates of 2.8%. The BC Hydro CRI evaluation shows peak period reductions of 11.5% in year 1 and 11.1% in year 2. Since customers self-selected to participate in the BC Hydro study, it is reasonable to assume that they are more price responsive than the general population. The NewMarket results are consistent with the BC Hydro CRI results assuming an average effective participation of 25%, i.e. 25% of the customers placed on the TOU rate actually respond to the price signal. We recommend using the BC Hydro value rounded down to 11% as the response for the responsive customer. We recommend forecasting a range of 20% to 30% of customers as being responsive.

CPP and CPR

We recommend using the 10% savings for critical peak hours for CPP and CPR based on the preliminary results from the BC Hydro CRI year 2 participants in CPP. This 10% reduction during critical peak hours is in addition to the 11.1% reduction due to the TOU rates. The Woodstock CPP program showed an 11.9% reduction. We recommend using the slightly lower BC Hydro savings because of the proximate location, being more recent, and because it is implemented in addition to the TOU rates.

Energy savings from CPP and CPR are assumed to be negligible without supporting technology, due the very small number of critical peak hours. The energy savings with supporting technology is the 5.4% that can be attributed to the IHD.

Inclining Block Rates

The 1.8% savings for the inclining block rates is based on the BC Hydro estimates from its "2008 Residential Inclining Block Application" where they estimated conservation savings of 200-523 GWh from a customer eligible load of 17,108 GWh (BC Hydro, 2008a). The 6.3% impact with supporting technology assumes that half of the elasticity effect from the inclining block rate is captured in the 5.4% additional savings from supporting technology. Without TOU rates, we assume that inclining block rates will have negligible peak savings.

Pre-pay

We recommend using the 11.7% savings from pre-pay based on the Woodstock Hydro program results. This is consistent with the 12% savings observed in the Salt River Project (SRP) program. The impact of supporting technology (e.g. IHD) would be to increase by 50% to 17.5%. This 5.8% increase in conservation is consistent with the 5.4% impact of real-time consumption feedback reported in the ACEEE meta-analysis (ACEEE, 2010).

Neither the Woodstock nor SRP program provided data on peak demand savings. We conservatively assume that without supporting technology and TOU rates, there will be no peak period reductions.

Load Control

Load control peak savings of 13% is based on the FERC as demand response assessment. Load control entails installing the switches that are included in the supporting technologies. Thus, the supporting technology scenario has no change in impact.

We assume energy savings from pure load control programs are negligible, consistent with the evaluation results of multiple load control programs. Loads are typically controlled for less than 80 to 100 hours per year (less than 1% of the hours) and there is often some payback after the load control event. BC Hydro observed a less than 1% reduction in peak period consumption for the direct load control participants in its CRI program (LeClair, 2010).

In-Home Displays (IHD)

The IHD saving was forecasted to be 5.4% of annual energy use based on the ACEEE meta-analysis of 36 residential feedback pilots and studies conducted between 1995 and 2010. The peak demand savings were estimated to be half of the annual energy savings as a conservative assumption (this assumption was also applied to the pre-pay rates). The ACEEE meta-analysis found that many of the conservation actions employed focused on the non-space conditioning loads. Thus, one would expect the peak demand savings to be less than the annual energy savings. A portion of the annual energy can be expected to occur during peak periods. With supporting technology, the peak load impacts are assumed to be the same 20% reduction from the load control switches (i.e. the IHD provides no incremental demand reductions over the load control switches).

Participation Rates

Most of the pilots and programs reviewed were conducted with volunteers. Customers who volunteer to participate in the programs are more likely to respond to the price signals, incentives and information than other customers. In order to forecast the benefits from a system-wide roll-out of the programs, the per participant impacts need to be adjusted to reflect participation rates. In some instances, for example – TOU default rates, while all customers see the rates only a subset will actively respond to price signals. Reconciling the BC Hydro 11% peak savings for TOU rates with the 2.8% peak savings could imply that approximately 20% to 30% of customers actually respond to the price signals.

In order to estimate net energy and capacity benefits from future programs, participation forecasts are required. There are two radically different approaches to these future programs.

- ***Opt-In***—programs are offered as options and customer enrolls voluntarily.
- ***Opt-Out***—customers are assigned to the program. In some cases, they may choose not to participate. For example, a customer may refuse to have an IHD installed. In other cases, the customer may not pay any attention to the incentives or price signals such as for a TOU or a CPP default tariff program.

There is limited data on participation rates, in some cases, e.g. TOU programs, implied participation rates can be inferred by comparing savings from mandatory programs to voluntary programs[11], or by looking at the percentage of customers that provide savings.

The ACEEE meta-analysis used the following participation for real-time residential feedback programs:

- Opt-in: 3% to 8%
- Opt-out: 65% to 75%

The Hydro One TOU pilot had 13% of the customers solicited agreeing to the TOU rates, of these, 72% said that they would like to stay on the TOU rates implying long-term participation rates of 9%. The NewMarket Hydro TOU pilot was run as an opt-out program. Approximately 37% of the customers opted out.

[11] Such comparisons can only be indicative because many factors, e.g. specifics of tariff design, weather, demographics, etc. could also drive the observed differences.

Recommended participation rate assumptions by program scenario are summarized in Table 17: AMI Future Program Participation Rate Assumptions. The TOU and CPP/CPR low opt-in assumption of 9% is based on the 13% participation rate from the Hydro One pilot times the 72% that expressed a desire to say on the TOU rates. The 20% and 30% rates for high opt-in and opt-out program scenarios are the 20% to 30% participation recommendations discussed in the *"TOU"* subsection above.

The inclining block rate savings are based on an elasticity estimate and implicitly applied to all eligible customers.

The pre-pay participation rates are based on the IHD participation rates for the opt-in program scenarios. It is assumed that neither pre-pay nor load control would be offered as an opt-out program. The load control participation rates are based on utility experience with load control programs.

The IHD participation rates are the same assumptions used by the ACEEE in their meta-analysis.

Table 17: AMI Future Program Participation Rate Assumptions

<table>
<tr><th colspan="2" rowspan="2">Program Type</th><th colspan="2">Opt-In</th><th colspan="2">Opt-Out</th></tr>
<tr><th>Low</th><th>High</th><th>Low</th><th>High</th></tr>
<tr><td rowspan="3">Conservation Rates</td><td>TOU</td><td rowspan="2">9%</td><td rowspan="2">20%</td><td rowspan="2">30%</td><td rowspan="2">60%</td></tr>
<tr><td>CPP/CPR</td></tr>
<tr><td>Inclining</td><td colspan="4">Not Applicable</td></tr>
<tr><td colspan="2">Pre-Pay</td><td>3%</td><td>8%</td><td colspan="2" rowspan="2">Not Applicable</td></tr>
<tr><td colspan="2">Load Control</td><td>5%</td><td>15%</td></tr>
<tr><td colspan="2">In-Home Displays</td><td>3%</td><td>8%</td><td>65%</td><td>75%</td></tr>
</table>

Program Benefits and Costs

Energy and Capacity Savings

The energy and capacity benefits from these future programs were forecasted for each program participation scenario for 2018. Year 2018 was selected for developing the forecasts based an assumed 2014 launch date and it would take approximately three years before the full participation rates are achieved. The forecasted capacity savings are summarized in Table 18: 2018 Capacity Savings (MW and % of Residential Load) and the forecasted energy savings are summarized in Table 19 2018 Energy Savings (MWh and % of Residential Sales).

Table 18: 2018 Capacity Savings (MW and % of Residential Load)

	Opt-In		Opt-Out	
	Low	High	Low	High
TOU	2.7	6.0	9.0	18.1
	0.89%	1.98%	2.97%	5.94%
TOU w Support	4.1	9.0	32.6	35.3
	1.34%	2.97%	10.74%	11.60%
CPR & CPP	2.5	5.5	8.2	16.4
	0.81%	1.80%	2.70%	5.40%
CPR & CPP w Support	-	-	31.4	32.8
	-	-	10.33%	10.79%
Incline Block	4.9			
	1.62%			
Pre-pay	0.5	1.3	Not Applicable	
	0.16%	0.42%		
Pre-pay w Support	0.7	1.9		
	0.23%	0.63%		
Load Control	1.8	5.5		
	0.60%	1.80%		
In-home displays	0.2	0.6	4.8	5.5
	0.07%	0.19%	1.58%	1.82%

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Table 19: 2018 Energy Savings (MWh and % of Residential Sales)

	Opt-In		Opt-Out	
	Low	High	Low	High
TOU	6,762	15,028	22,541	45,083
	0.45%	0.99%	1.49%	2.97%
TOU w Support	10,144	22,541	59,632	78,690
	0.67%	1.49%	3.93%	5.18%
CPR & CPP	-	-	-	
	0.00%	0.00%	0.00%	
CPR & CPP w Support	-	-	47,951	55,329
	-	-	3.16%	3.65%
Incline Block	24,590			
	1.62%			
Pre-pay	4,795	12,787	Not Applicable	
	0.32%	0.84%		
Pre-pay w Support	7,193	19,181		
	0.47%	1.26%		
Load Control	-	-		
	-	-		
In-home displays	2,213	5,902	47,951	55,329
	0.15%	0.39%	3.16%	3.65%

The year 2018 capacity savings (also shown in Figure 9: Capacity Savings (MW) in 2018 by Program Scenario) range from a low of 200 kW for the low participation, opt-in scenario for IHDs to a high of 31 MW for the TOU with supporting technology for the opt-out scenario. The high energy savings for the TOU and CPP/CPR opt-out scenarios are driven largely by the supporting technologies. Not only do the supporting technologies enhance the savings for the participants in these rate programs, but they also result in savings from the non-participants in the conservation rate programs.

Figure 9: Capacity Savings (MW) in 2018 by Program Scenario

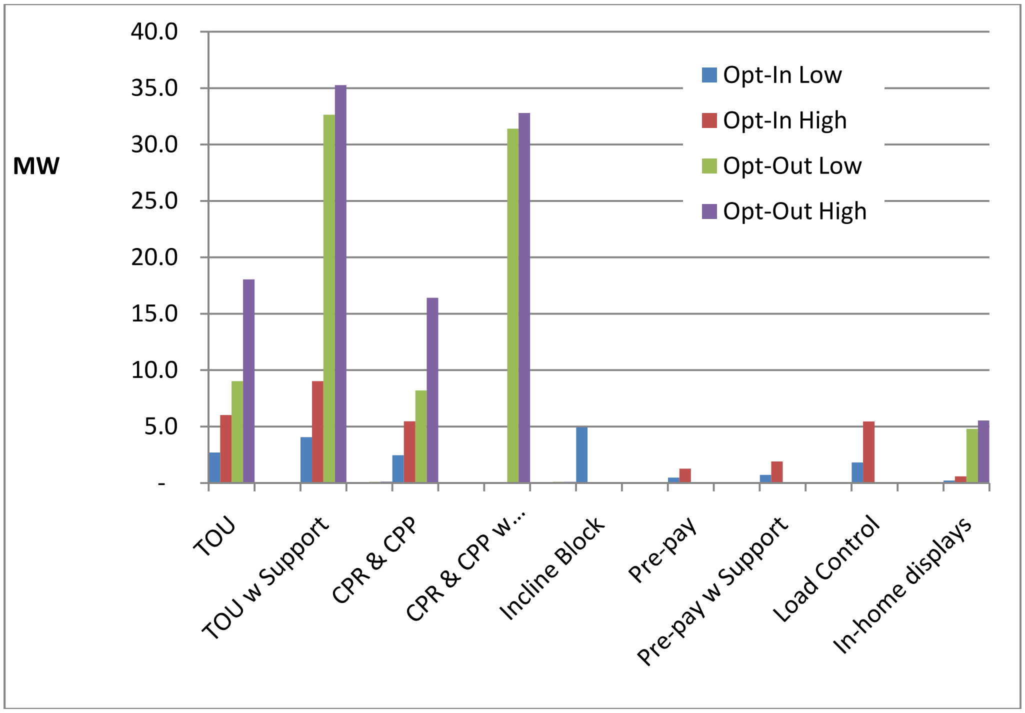
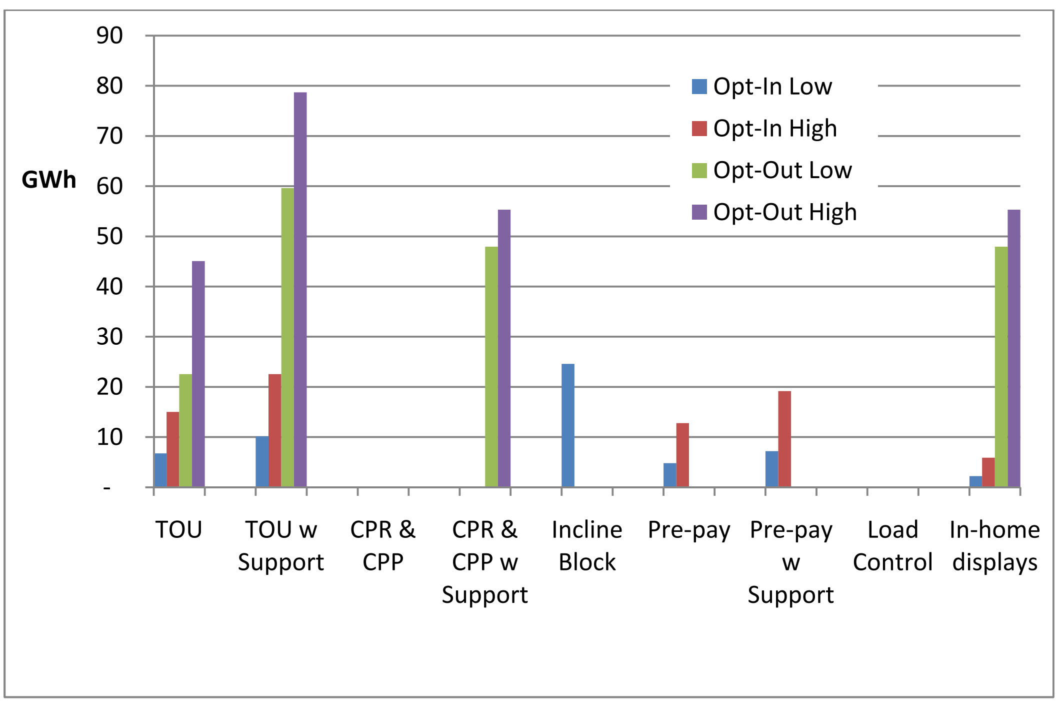


Figure 10: Energy Savings (GWh) in 2018 by Program Scenario



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Assumptions

Key assumptions used in the calculations of the costs are summarized in Table 20: Key Assumptions and Table 21: FortisBC Forecast Data.

Table 20: Key Assumptions

Constants	Value	Units	Source
Program Start Year	2014	yr.	FortisBC Estimate
Present Value Year	2010	yr.	NCI Assumption
Residential Demand % of Peak Capacity	39%	Percentage	Residential average annual coincident peak demand from Cost of Service Analysis (FortisBC, 2009)
Residential Customers	95,502	Customers	FortisBC. "2009 Resource Plan", May 2009. P. 71
Persistence	90%		NCI Assumption
T&D Line Losses	9%	Percentage	FortisBC. "2008 Actual System Related Load Data", 2010.

Table 21: FortisBC Forecast Data

Year	Peak Load Forecast for All customers (MW)	Annual Energy Sales for Residential Customers (GWh)
2014	744	1,303
2015	754	1,324
2016	764	1,344
2017	773	1,365
2018	783	1,386
2019	793	1,407
2020	803	1,427
2021	813	1,447
2022	823	1,468
2023	833	1,488
2024	843	1,507
2025	853	1,527
2026	862	1,546
2027	872	1,564
2028	881	1,582
2029	891	1,600
2030	900	1,617
2031	909	1,634
2032	918	1,650
2033	927	1,665

Source: FortisBC. "Forecast Energy Sales by Class (GWh)" and "Peak Forecast (MW)" Microsoft Excel Document Received on January 14, 2010.

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Conclusions and Recommendations

The evaluation of utility programs demonstrates that significant benefits can be realized through the implementation of AMI future programs functionality. Conservation reductions with supporting technology range with from of $395 to $1389 per customer for FortisBC. The analysis shows that:

- Inclining block rates provide the smallest benefits. Since FortisBC plans to roll-out TOU rates in 2014, and rate changes create customer confusion, there is little value to rolling out inclining block rates as an interim program.
- The research shows that on-going communication and marketing is essential for maintaining the behavioral savings. An on-going communication and marketing program (and the associated annual costs) need to be part of the program. The capacity and energy savings benefits and customer costs analysis included applicance on-going communication and marketing costs.
- The supporting technology (IHD) and appliance controllers produce substantial additional benefits regardless of the underlying rates and should be deployed as part of any program.
- TOU supplemented with supporting technologoes provides the greatest savings at the lowest costs per participating customer.

FortisBC should offer a default TOU program (conservative assumptions about the savings from TOU were used, reflective of a deafault program) coupled with supporting technology. Additional benefits can be realized by offering pre-pay and CPP/CPR options.

The utility interviews also identified a number of recommendations, summarized in

Table 22: Key Recommendations from Utility Interviews.

Table 22: Key Recommendations from Utility Interviews

Key Driver of Program Savings	Lessons Learned
Peaking Period	• If technologically possible, provide energy demand information at the customer appliance level in order to inform customers on which major appliances to adjust during peak periods, e.g. electric space heating. (Hydro One, 2010) • Provide residential customers with higher price signals during non-discretionary demand periods in the winter as customers tend to be less responsive to peak events during winter peak periods (morning and evening hours) when compared with summer peak afternoon hours (Avista, 2010)
Customer Persistence and Satisfaction	• Minimize customer activities required to operate and maintain IHDs (e.g. installation, programming updates, and replacing batteries) with automated and utility controlled technology where possible (Hydro One, 2010; Avista, 2010) • Implement price signals with enabling technologies (e.g. IHD) to incentivize ongoing customer participation (Avista, 2010). Without price signals, savings from IHD decay quickly (Avista, 2010)
Program Design	• For a voluntary program, involve local community partners and municipalities to encourage customer awareness and adoption (Ameren, 2010) • Design the program to be simple and implement a pricing structure that are clear to help customers understand the benefits of participating (BC Hydro, 2010) • Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements (PG&E) • Keep program informational materials concise and easy to understand to reduce customer questions and additional customer communication costs (PG&E)
Program Implementation	• Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements (PG&E) • Ensure meters operate and are configured correctly during rollout (BC Hydro)
Sources: Ameren, 2010. Personal communication. January 2010. Avista, 2010. Personal communication. February 2010. BC Hydro, 2010. Personal communication. January 2010. Hydro One, 2010. Personal communication. January 2010. PG&E, 2010. Personal Communication. January 15th, 2010.	

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   This 2009 report prepared by the Federal Energy Regulatory Commission for Congress forecasts the potential for demand response in the U.S. and includes the following:

   a. Estimation of nationwide demand response potential in 5 and 10 year horizons on a State-by-State basis, including a methodology for updates on an annual basis;
   b. Estimation of how much of the potential can be achieved within those time horizons, accompanied by specific policy recommendations, including options for funding and/or incentives for the development of demand response;
   c. Identification of barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available; and
   d. Recommendations for overcoming any barriers

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   This study analyzes the results of 57 primary research studies on providing electricity consumption feedback to residential customers. Twenty three of the studies included real-time usage feedback. The study examines issues related to participation rates, persistence, and the effects of different forms of feedback.

3. (Faruqui, 2009). Ahmad Faruqui, Sanem Sergici and Ahmed Sharif "The Impact Of Informational Feedback On Energy Consumption—A Survey Of The Experimental Evidence," The Brattle Group. 2009

   This study completed in 2009 reviews a dozen utility pilot programs in North America and abroad that focus on or experimented with in-home displays. It also reviews overall customer opinions and attitudes towards direct feedback from in-home displays to the extent that this information is available from the pilot studies.

4. (The Brattle Group, 2009). Ahmad Faruqui and Sanem Sergici, "Household Response to Dynamic Pricing of Electricity—A Survey of the Experimental Evidence," http://www.hks.harvard.edu/hepg/Papers/2009/The_Power_of_Experimentation__01-11-09_.pdf

   This study conducted in 2009 surveys evidence from 15 experiments on dynamic pricing of electricity.

5. (Edison Electric Institute, 2008). Prepared by Ahmad Faruqui, Ph.D. and Lisa Wood, Ph.D. "Quantifying the Benefits Of Dynamic Pricing In the Mass Market", January 2008, Appendix E.

   This study completed in 2008 compares results from 13 dynamic pricing and time-based rate pilots.

6. (PUF, 2010) Ahmad Faruqui, Ryan Hledik and Sanem Sergici. "Rethinking Prices: The changing architecture of demand response in America", Public Utilities Fortnightly (PUF) January 2010.

   This 2010 article published in the Public Utilities Fortnightly uses results from recent demand response pilots and studies to analyze the changing architecture of demand response in the U.S.

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Attachment 1: Primary Research

NCI interviews five utilities in total and sent each a sample interview guide prior to the discussion. The interviews differed slightly depending on the knowledge and relvance of the questions for each utility. The detailed notes included in this section paraphrase the relevant content from the interviews.

Notes from Interviews

Sample Interview Guide

Background

Navigant Consulting, Inc. (NCI) is assisting FortisBC, an electric utility located in British Columbia, in an assessment of mass market conservation demand management functionality enabled by advanced metering infrastructure (AMI). To build on efforts from other utility deployments and pilot programs, we are interviewing utility experts with AMI program experience to gain an in-depth understanding of the lessons learned, customer education requirements, and benefits/costs associated with offering conservation demand management as part of an AMI program. Our assessment focuses on conservation demand management functionality including load control (e.g., demand response), in-home displays, and various pricing programs (e.g., innovative rates, conservation rates, and pre-paid metering).

Questions

1. *Can you briefly describe your background and experience working on your utility's AMI and conservation demand management related programs?*
2. *Please briefly describe the components of your AMI and conservation demand management programs. What pricing programs and/or rate structures are you offering? How effective are each and how difficult are they to implement? Which of the following features does your program include?*
    a. *Demand Response / Load Control; in-home displays; innovative rates (Time of Use [TOU] enabled by AMI, Critical Peak Pricing [CPP], Critical Peak Rebates [CPR], Incline Block with access to real time information, EPP with CPR); Pre-pay (EPP)*
3. *Do you have any results/benefits that you can share (i.e., % energy and capacity savings, elasticity associated with pricing differentials) associated with the features listed below? Do you have an estimate for the incremental costs typically associated with each (e.g., costs related to billing system changes and/or increased system bandwidth for real-time data)*
    a. *Load control devices (e.g. utility controlled demand response enabled by AMI)*
    b. *Innovative rates linked to AMI*
    c. *In-home displays of customer usage information/data*
4. *What types of customer education or communications activities were needed to support your AMI related conservation demand management and pricing program? How much did you spend on these activities (total cost, and/or cost/customer)? How much did you spend on customer service associated with the conservation demand management program, and what advice would you offer to minimize customer call volume?*
5. *What are some of the lessons learned from your AMI enabled conservation demand management program? What additional advice can you offer to a utility planning to deploy AMI systems with conservation demand management functionality?*

Ameren Interview Notes

Date	January 20, 2010
Organization	Ameren

1. Can you briefly describe your background and experience working on your utility's AMI program?

- *I have experience working on and guiding the implementation of both the Power Smart Pricing (PSP) program and our AMI deployment. Recently, I have been working as a liaison between our company and CNT Energy. CNT Energy is responsible for all the marketing and customer education associated with the PSP program. I have also worked on some regulatory projects dealing with billing issues and other projects.*

2. Can you describe the load control and pricing schemes of your pilot and AMI program?

- *Enhancing customer service was the main objective of Ameren's AMI program. Our AMI system provides real-time information to customers on energy prices and also uses a CellNet radio configuration that transmits data on our customers' energy usage. Our network currently uses one-way communication, but has the capability for two-way communication if we decide to implement it. Reducing costs and O&M associated with meter reads was a secondary benefit. On college campuses for example, there are often a significant number facilities that require meter reads towards the close of the school year, and our AMI system's ability to automate the meter reading process has significantly reduced the number of manual meter reads required.*
- *Ameren is just finishing our first phase of the smart meter deployment. The next phases will involve potentially expanding the AMI program to all customers and integrating AMI with the state of Illinois's goals for a smart grid.*
- *For the PSP pilot, a PriceLight (a small orb that glows different colors based on the current estimated price of electricity) was the only in-home display device we used. About 100 customers with the PriceLight were monitored and the data shows that these customers seemed to be more responsive to price changes. The PSP pilot also used real-time pricing (RTP). Illinois Public Act 94-0977 required that electric utilities which serve more than 100,000 customers must have RTP available to residential customers as a rate option.*
- *AMI customers were using the same real-time pricing (RTP) rates as the rest of Ameren's customers and as of June 2009 we switched to an hourly day-ahead pricing scheme. These day-ahead estimates of hourly prices don't exactly match RTP, but they are fairly close. We did not develop special rates for AMI as these meters were deployed to collect information primarily for billing purposes and cost saving.*
- *We spent roughly $1 million for our meter data management system, but I don't have much other cost information at this time.*

3. What types of customer education or communications activities were needed to support your AMI related conservation demand management and pricing program? How much did you spend on these activities?

- *Several on-line tools have been developed for computer users to monitor energy prices while they're logged onto the Internet. These include our PSP website which displays the current cost of energy, Google and Vista gadgets that display prices graphically, and an application that displays the current price on the computer web browser toolbar. Day-ahead phone call notifications were used to alert customers of peak events.*

- *I don't have any of this cost data for AMI, but the PSP program marketing and customer education costs are equivalent to what we paid CNT Energy we outsourced all of these responsibilities to them. Other costs of the Power Smart Pricing program consist of the incremental cost of metering to collect hourly usage data, additional Ameren Illinois Utilities' expenses for software and data processing systems, and the program administrator and evaluation contracts.*

4. Do you have any results/benefits that you can share (i.e., % energy and capacity savings, elasticity associated with pricing differentials) associated with the PSP program?

- *Since Power Smart Pricing launched in early 2007, participants have saved an average of 17% compared with what they would have paid on the standard fixed rate (based on billing results from May 2007 through September 2009). Average annualized customer savings for 2008 (which account for the growing participation level across the year) were $92.65 or 7.7% (this does not include additional savings associated with the conservation effect).*
- *High Price Alert Days, the PriceLight, weekends and the year were all statistically significant factors that effected elasticity:*
    a. *Customers did pay attention to High Price Alerts and increased their price response on those days*
    b. *Customers with PriceLights showed an even greater response to price changes, and this effect shows up across all days throughout the summer season*
    c. *On average, customers showed additional price response on weekends compared to weekdays*
- *Survey responses from these customers show high percentages of satisfaction with the program, with 71 percent of customers reporting that they find participating in PSP "quick and easy."*

5. What are some of the lessons learned from your AMI enabled conservation demand management and PSP pilot programs?

- *Interference on the radio communication network has been a problem and required additional estimates for the energy consumption of hourly billed customers whose signal was interrupted. Sometimes this interference even requires us to send an employee into the field to verify consumption estimate.*
- *Setting realistic expectations for customers and involving local community partners and municipalities help improve customer acceptance and satisfaction. For example, we clearly articulated to our customers that we would reduce meter reads rather than eliminate meter reads entirely. Also, we developed informational material that local news organizations could broadcast to explain the meter exchange process.*
- *Start communicating early in the deployment with and helping transition employees whose jobs may be at risk with the technology deployment.*
- *Establish payment for vendors to correspond with verification of accurate meter reading and full system functionality rather than just meter installations.*

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Avista Interview Notes

Date of Interview	February 5th, 2010
Organization	Avista Utilities

1. Please describe the components of your demand response pilot program.
    - *Over the past two years our demand response pilot program tested the effectiveness of smart thermostats and direct control unit (DCU) switches for customer appliances. The pilot involved over 70 residential customers with roughly 50 programmable thermostats and about another 50 load control switches used on customer appliances (e.g. water heaters, compressors, heat pumps, and AC units). These appliances were chosen based on their compatibility with our equipment.*
    - *Our main goals involved testing customer acceptance and cost effectiveness.*
    - *This was a voluntary program that allowed customers to opt out but only a few with morning water heater demand chose to opt out. The events were called on weekdays during the winter and summer peak periods. Customers were notified by phone one day in advance of a peak event.*
    - *We used a one-way paging system with five minute interval data for the devices.*
    - *The report on this project will be submitted to the Idaho Public Utilities Commission on March 1st, 2010.*

2. Can you describe the customer acceptance of the program and technology?
    - *Customers tended to be very enthusiastic about the smart thermostats and energy management capability at the start of the pilot, but after a few months the novelty for customers seemed to wear-off and participation dropped. Battery failures in some of our devices were also partly to blame for lower participation and some dissatisfied customers.*
    - *Most customers found the program favorable and early adopters of the technology in particular seemed very happy with the program.*
    - *The turnover in homes with customers that had signed-up for the program was challenging as customers that moved into a house with a smart thermostat installed by a previous resident rarely chose to participate in the program. This left us with stranded assets since thermostats were already installed. The new customers probably would have been more likely to participate if Avista used additional incentives such as a dynamic rate.*
    - *For the smart thermostats we initially mailed information to about 3,000 customers of whom 300 responded and ~50 were randomly selected to receive a thermostat for the pilot.*
    - *For the DCU we had about 130 people that originally qualified for the program, but many dropped-off due to the delay between the initial notification and the technology implementation.*

3. Did you test any dynamic rates during the program?
    - *No, we only used the traditional rate for our program.*
    - *The lack of dynamic pricing meant customers had less incentive to participate during peak events and reduce their load with the smart thermostats. I anticipate participation and savings would have been higher if we used dynamic rates instead of the traditional rate.*

4. Can you provide us with a breakdown of the program costs?
    - *This entire pilot program cost US$123,000 for 2 years which included customer incentives, equipment costs, roughly US$1,000/month hosting fee for the vendors, and US$2,000 for marketing through an advertisement agency.*
    - *Avista paid customers with a DCU about $10/peak month for participating during peak events. Avista provided no cash incentives to use the smart thermostats, but these customers did receive a free thermostat.*

5. Do you have estimates of program savings during winter?
    - *We did not have sufficient data to measure the average energy reduction, but we estimate savings are consistent with other pilots of this nature. We originally thought the meters would provide us with these estimates, but this was not the case. For DCU we used industry standards to estimate savings by device of 0.33kW for water heaters, 1.5kW for electric heaters, and 1kW for AC units.*
    - *Many of our customers traveled during the winter and summer peak periods which also made it difficult to estimate savings.*
    - *Customers tended to be less responsive to peak periods during the winter when compared with the summer.*
    - *Given the high overhead and administrative costs required to deploy a small number of devices for this pilot, Avista's preliminary analysis suggests the program is not cost effective at this scale.*

6. What are some additional lessons learned from your conservation demand management program?
    - *Don't begin marketing for the deployment until contractors are trained and ready. After the initial marketing phase of our program the technology deployment was delayed and many customers lost interest in participating during this delay period.*
    - *Implementing price signals (e.g. dynamic rates) with the smart thermostats would have likely improved ongoing customer participation and savings.*

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BC Hydro Interview Notes

Date of Interview	January 18th, 2010
Organization	BC Hydro

1. Can you briefly describe your background and experience as it relates to conservation demand management and your utility's AMI program?
   a. *I work in the Conservation Rates department of the PowerSmart Group at BC Hydro where I focus on time-of-use (TOU) related to AMI. I began working at BC Hydro as part of the Conservation Research Initiative, which was a two year pilot, conducted between October 2006 and October 2008. The pilot is finished and the report will likely be released sometime in late February or March 2010.*

2. What type of load control and pricing schemes did you use during the pilot?
   a. *Key components of the pilot were supplied by three separate vendors and included smart meter replacements for roughly 2,000 customers and a few different network topologies. We used several rate options including TOU, critical peak pricing (~100 customers), critical peak rebate, and varying off-peak structures. Customers participated on a voluntary basis, but did not choose their tariff. They also had the option to opt-out of a CPP event on a per event basis, but there was only one record of a customer doing this during one winter CPP event.*
   b. *The pricing differential for TOU between peak and off-peak ranged from 2-1 and 6-1.*
   c. *There was also a load control 45 households with electric heating. The load control units operated with a separate network.*

3. What were the incremental costs and saving for each feature?
   a. *We may be able to reverse engineer load control costs, but TOU will likely be too difficult. There are valuable lessons to be learned from a 2,000 customer pilot, but the cost data from the programs were not meant to model full-scale deployment. Also, the direct costs of the program may be outdated.*
   b. *On-peak savings from TOU were around 11.5%*
   c. *We also saw higher levels of overall conservation than expected even though the program was more focused on peak reduction*

4. Did your pilot include in-home displays?
   a. *At the start of the pilot, we began installing in-home displays (IHD) for 250 households. We used Blue Line Innovations PowerCost Monitors, but since the technology was in its early development stage back in 2006, they had several technical issues and a problem communicating to the meter across residential property. To resolve this issue, we had to replace about 2/3 of the IHDs with newer models after the first year. The monitors also had several levels of customer communication. The basic communication included a*

welcome pack explaining the customer's tariff and recommendations for shifting behavior. Enhanced communication provided additional information on TOU rates and community benchmarks.

5. How do you plan to go forward with your AMI program?
    - *This pilot was designed to provide us with a customer view and there are a number of lessons learned that will inform future smart metering work. There are also a number of other utility programs worth looking at with larger and more relevant data points to the customer population.*

    - *The implementation of TOU will likely be very different. We will likely implement a blend of CPP and TOU, but we still need to do the rate design before we make any decisions.*

6. Do you have any results/benefits that you can share on elasticity?
    - *Elasticity is difficult to estimate since we didn't have enough of the controls in place to separate experimental adjustments from other factors. For example, many of our customers made the decision to participate not based on the economic incentives, but rather the idea that they were making a socially responsible decision by reducing energy usage. While the customers had a lot of support and education, they often did not have a clear price signal that influenced their decision.*

7. What types of customer education or communications activities are needed to support your AMI related conservation demand management and pricing program? How much did you spend on these activities (total cost, and/or cost/customer)
    - *We provided a considerable amount of customer education. We also had an annual event for participating customers where we summarized results and customers shared recommendations for shifting load. This program required a lot of customer support and service, so we also developed a separate phone and email line for customers.*

8. What are some of the programmatic insights or lessons learned from your AMI enabled conservation demand management program? What additional advice can you offer to a utility planning to deploy AMI systems with conservation demand management functionality?
    a. *It is very important to effectively communicate with customers.*
    b. *While customer response to load control and CPP was very positive, the process of implementing load control for winter peaking utilities still needs some work to make it practical on a larger scale. Our load control installations were a significant challenge as some customer homes required re-wiring and dry-wall patching. Also, the cost of a licensed electrician to install these devices for each customer is significant.*
    c. *When implementing alternative pricing schemes, try to choose a design that is clear and easy for customers to understand. We used a fairly complicated TOU model which was a challenge for customers to understand as they had previously been on a flat base rate. We decided to increase peak rates, but kept off-peak rates the same as the base rate rather than lowering them, so many customers didn't think they were saving money. To reassure customer savings we agreed to give them a bill guarantee that would compensate them if they did not save money compared to the previous year's charges. This bill guarantee*

came in the form of a rebate on the customer's bill. Roughly 2/3 of the customers saved money during both years, and 1/3 needed the bill guarantee.

d. *The study we are drafting contains additional lessons learned relative to future technology implementation pilots such as how to establish a micro AMI environment and tips for meter replacements. For example, it is critical to notify customers in advance when you are going to disrupt their electricity to replace a meter.*

e. *You can refer to the public applications and tariff regulatory filing to see the way the pricing was implemented and organized. The 1141 customers (rates for people in Lower Mainland and St. John) used these TOU rates from November to February.*

Hydro One Interview Notes

Date of Interview	January 20, 2010
Organization	Hydro One

1. Can you briefly describe your background and experience working on your utility's AMI program?
   - *I work at Hydro One and have experience working on the in-home display (IHD) and time-of-use (TOU) programs where I dealt with marketing and implementation related issues.*

2. Please briefly describe the objectives of your AMI program.
   - *Our regulator has mandated that we install smart meters for all our customers by the end of 2010 and offer TOU rates by the end of 2011.*

3. What costs are associated with IHDs and billing rate changes such as TOU or CPP? Do you have any results that you can share on these programs?
   - *At the start of the IHD deployment, we paid roughly $150 per IHD device which included hardware, marketing and shipping, but hardware costs have since decreased. We outsourced shipping and marketing to a third party while most customers self-installed the devices on a voluntary basis.*
   - *The IHD installations on average reduced energy by 6.5%; when IHD was combined with TOU the savings were slightly higher at 7.6% (4.3% from IHD and 3.3% from TOU).*
   - *We don't have much detail on the costs of billing rate changes as we typically track costs on a full deployment basis.*

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4. What types of customer education or communications activities were needed to support your AMI related conservation demand management and pricing program? How much did you spend on these activities?

   - *The pilots tried to minimize the amount of customer education and marketing to isolate the impact of just the technology. The TOU pilot for example tested customer response to purely to price information rather than conservation recommendations.*
   - *For the deployment, we spent $25- $50 per customer on education and marketing which included customer*
   - *calls and informational instructions mailed with the device.*

5. What are some of the lessons learned from your AMI enabled conservation demand management program? What additional advice can you offer to a utility planning to deploy AMI systems with conservation demand management functionality?
   - *For the first IHD pilot, separating out the feedback from the electric heating load and the rest of the load may have helped encourage conservation. Many of the houses in the 500 customer pilot with electric space heating were less responsive to real time feedback. For example, the IHD reduced load by 1.2% in these houses compared to the 6.7% average reduction from IHDs.*
   - *Real-time feedback of energy consumption is effective in promoting conservation even without real-time pricing*
   - *Based on results of the Time-of-Use Pricing Pilot, 76% of pilot participants under the Regulated Price Plan (RPP) TOU rates paid a lower electricity bill as a result of load-shifting compared to the regular RPP rates. Savings attributable to conservation would be incremental. Customers who were better off gained on average about $23 during the pilot (about $6 per month), while customers who were worse off on average lost about $7 (less than $2 per month).*
   - *IHDs that can be remotely updated by the utility or AMI system are often more effective in promoting conservation as customers rarely program these devices on their own (e.g. programming updates to TOU periods). We would make this a priority feature for future deployments so we could implement Critical Peak Pricing or other conservation rates if we choose to.*
   - *IHD technology powered from the house circuit rather batteries tends to be more reliable as we had a problem with the batteries of our earlier models*
   - *IHDs that require a licensed electrician to install tend to be more expensive and potentially risky for homeowners to install themselves*
   - *Of the 30,000 IHDs installed only 29% are still in use and 15% were never installed or used by customers. To improve participation we recommend that future programs eliminate the need for customer installation and/or provide incentives for customers to install and use the technology. Offering cash incentives for customers to install and use the IHD device or charging customers more for the device may improve ongoing participation. Even when we charged the customer $10 for shipping, there was still very little incentive for customers to install them. I do not recommend giving the device to customers for free.*

PG&E Interview Notes

Date	January, 15th 2010
Organization	PG&E

1. Can you briefly describe your background and experience working on your utility's AMI program?
   - *I work in the smart energy web group at PG&E and help explore innovative customer products related to energy efficiency, demand response, and behavioral changes. I also do work on PG&E's home area network (HAN) strategy, which we plan to launch in the next year and will provide customers with access to usage and additional demand response programs.*
   - *I have limited experience on the Ancillary Services and Automated Demand Response Pilots.*

2. Please briefly describe the components of your AMI program. How effective are each and how difficult are they to implement?
   - *We currently offer a SmartRate pricing scheme, which shifts peak demand by providing voluntary critical peak pricing for our smart meter customers. Customers receive a discounted rate except for non-critical peak periods and then pay more during critical peak periods. There is a relatively small adoption rate in the hundreds of thousands.*
   - *We also offer a voluntary time of use (TOU) rate for some customers with PV systems, but less than a hundred thousand customers have adopted this program. We have plans to enroll all commercial customers in either the SmartRate program (default option) or the TOU pricing scheme (alternative to SmartRate).*
   - *SmartAC is our direct load control program for the mass market including residential customers. We contract out to a 3rd party who installs a device that can receive a signal to reduce the demand of the AC system. I don't have specific data on this program.*

3. How much did you spend on customer education and communications activities?
   - *I don't have much information on the program costs for the SmartRate program.*

4. Do you have any results/benefits that you can share from your innovative rates, load control, or in-home displays?
   - *I don't have information for you on the costs and benefits per customer for the SmartRate program.*
   - *PG&E does not have much experience with in-home displays, but we have future plans to support in-home displays with our AMI program*

5. What are some of the lessons learned from your AMI enabled conservation demand management program? What advice would you offer to minimize customer call volume?
   - *Having a thoughtful and well-paced roadmap or implementation plan which allows time for customers to gradually adapt to changes and gives priority to technology that is compatible with future enhancements will help any utility's smart grid program. This is a huge paradigm shift for customers, so it is important not to overload them with changes at the beginning.*
   - *One key recommendation I have to reduce customer call volume would be to keep the program simple. For example, dynamic pricing can be confusing and difficult for customers to reverse engineer so implementing a pricing structure that is straightforward and clear, will help customers to understand the benefit proposition. Keeping the message, numbers, and implementation simple will likely be a more successful program than a rate structure that has optimized rates.*
   - *Additionally, too much information can also be confusing for customers as well as third party contractors that assist customers. Our customers always seem to have questions on what we send them, so sending less material could help reduce questions.*

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Attachment 2: Utility Research Table

Table 23: Detailed Utility Research Table

Utility	Location	Program/Pilot	Source(s)
Ameren	Illinois	Power Smart Pricing (PSP) program	Summit Blue Consulting, "Power Smart Pricing 2008 Annual Report," March 31 2009. Voytas, Rick, "AmerenUE Critical Peak Pricing Pilot", presented at U.S. Demand Response Research Center Conference, Berkeley, CA., June 2006 CNT Energy and Summit Blue, "Residential Real-Time Pricing Program Achieves Savings for Utility and Customers", Draft Paper, November 2009.
Ameren	Illinois	Smart Meter Deployment	Ameren, 2010. Personal communication. January 2010. Ameren, 2006. "Automated Meter Reading." Ameren Services. Web. 18 Sept. 2010. <http://www.ameren.com/Residential/ADC_AMR.asp>.
Avista	Washington and Idaho	Demand Response Pilot	Avista, 2010. Personal communication. February 2010. Avista, 2009. “2009 Electric Integrated Resource Plan,” Avista Utilities, August 2009.
Baltimore Gas and Electric	Maryland	Residential Smart Meter Pricing Program	The Brattle Group, "BGE's Smart Energy Pricing Pilot Summer 2008 Impact Evaluation." Prepared for BG&E, April 2009.
BC Hydro	British Columbia	Conservation Research Initiative	BC Hydro, "2009 Electricity Conservation Report", November 2009. BC Hydro, 2010. Personal communication. January 2010. BC Hydro, 2009. "Conservation Research Initiative." BC Hydro. Web. 18 January 2010.
BC Hydro & Newfoundland Power	British Columbia, Newfoundland & Labrador	BC Hydro and Newfoundland Power Pilot	CEATI, 2008. “Real-Time Feedback and Residential Electricity Consumption”, CEATI International Inc.
Commonwealth Edison	Illinois	The Community Energy Cooperative’s Energy-Smart Pricing Plan (ESPP)	Summit Blue Consulting, "Evaluation fo the 2006 Energy-Smart Pricing Plan - Final Report", 2007.
Connecticut Light & Power	Connecticut	Plan-it Wise Energy Pilot Program	The Brattle Group, "CL&P's Plan-it Wise Program Summer 2009 Impact Evaluation", November 2009.
Green Mountain Power	Vermont	AMI Pilot	Green Mountain Power, "2007 Sustainability Report," Oct. 26, 2007.
Hydro One	Ontario	IHD Program Deployment	Hydro One, 2010. Personal communication. January 2010.
Hydro One	Ontario	Time-of-Use Pricing/IHD Pilot Project	Hydro One, "Time-of-Use Pricing Pilot Project Results", EB-2007-0086, May 2008. Hydro One, "The Impact of Real-Time Feedback on Residential Electricity Consumption:

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			The Hydro One Pilot", March 2006.
Hydro Ottawa	Ontario	Ontario Energy Board Smart Price Pilot	Ontario Energy Board, "Ontario Energy Board Smart Price Pilot Final Report," Toronto, Ontario, July 2007.
Idaho Power	Idaho	Idaho Residential Pilot Program	Idaho Power, "Analysis of the Residential Time-of-Day and Energy Watch Pilot Programs: Final Report." December 2006.
Newmarket Hydro	Ontario	Newmarket Hydro Time-of-Use Pricing Pilot	Navigant Consulting, Inc. 2008. "Evaluation of Time-Of-Use Pricing Pilot," Presented to Newmarket Hydro Ltd. March 2008.
PG&E	California	Smart Meter and Voluntary SmartRate Program	Charles River Associates,"Impact Evaluation of the California Statewide Pricing Pilot", 2005. PG&E, 2010. Personal communication. January 2010. Bode, Josh. "How Well do Pricing Pilot Impacts Predict Actual Program Impacts?", Freeman Sullivan & Co. June 2009 EEI, 2008. Appendix C: The California Statewide Pricing Pilot Summary. January, 2008.
PG&E	California	Smart AC Ancillary Services Pilot	Rocky Mountain Institute,"Automated Demand Response System Pilot: Final Report", March 2006.
PG&E	California	Automated Demand Response System Pilot (ADRS)	Freeman, Sullivan & Co.,"2009 Pacific Gas and Electric Company SmartAC Ancillary Services Pilot", December 2009.
Public Service Electric & Gas	New Jersey	PSE&G Residential Pilot Program; MyPower Sense and MyPower Connection	PSE&G and Summit Blue Consulting, "Final Report for the Mypower Pricing Segments Evaluation," Newark N.J., Decemeber 2007. PSE&G and Summit Blue Consulting, "Residential Time-of-Use with Critical Peak Pricing Pilot Program: Comparing Customer Response between Educate-Only and Technology Assisted Pilot Segments." 2007.
Puget Sound Energy	Washington	TOU Program	Faruqui, Ahmad and Stephen S. George, "Demise of PSE's TOU Program Imparts Lessons," Electric Light & Power, Vol. 81.01:14-15,2003.
Salt River Project	Arizona	SRP M-Power Pre-pay Program	SRP, 2009. "SRP 2009 Annual Sustainability Report Summary."
Woodstock	Ontario	Pay-As-You-Go (Pre-pay)	Woodstock Hydro. "Pay- As-You-Go-Power: Treating Electricity as a Commodity", Ken Quesnelle (Vice- President). January 20, 2004
Xcel Energy	Colorado	Xcel Experimental Residential Price Response Pilot Program	Energy Insights, Inc."Xcel Enery TOU Pilot Final Impact Report", March 2008.; Energy Insights, Inc."Experimental Residential Price Response Pilot Program March 2008 Update to the 2007 Final Report", March 2008.