**1.0 Reference: Exhibit B-1, Table 7-2 Residential Inclining Block Rate Option Comparison; and Directive No. 5, Commission Order G-156-10**

**Customer Charge**

By Order G-156-10 the Commission directed FortisBC to develop a plan for introducing residential inclining block rates that also incorporates a lower Basic Charge in the immediate future. The Commission Panel acknowledges the lower Customer Charge of $21.50 tested in Options 10 to 18 by FortisBC but would appreciate receiving some additional Options explored for comparison.

1.1 Please model Options 19 to 24 for the three customer bill impact criteria based on thresholds of 1,350 and 1,600 kWh and a bimonthly Customer Charge of $10.00, provide the results of the analysis consistent with the format of Table 7-2 of the Application and provide a commentary of the initial screening analysis consistent with Table 8.1. Similarly show model Options 25 to 30 based on a Customer Charge of $15.00 and thresholds of 1,350 and 1,600 kWh (from Exhibit B-5, BCUC 1.12.7) and provide a commentary of the initial screening analysis. For ease of comparison, all the options with the Customer Charge of $10.00 and $15.00 are to be provided in the same table.

**Response:**

Please see the following table that compares the new options with the original 18 options, along with a table showing the detailed bill comparisons for each of the 30 options.

With the $10 customer charge, it is impossible to meet the 100% see <10% criterion with a RIB rate. Therefore, options 21 and 24 result in a flat block structure.

A lower customer charge benefits customers at low consumption levels and increases bills for customers with high consumption levels. This is also the case with a RIB rate. When both changes are implemented at the same time, the effects are compounded and exaggerate the bill impacts.

The FortisBC preferred option 8 (no change in customer charge, a 1600 kWh threshold and a 95% see <10% criterion) is comparable to options 23 and 29 that have the same characteristics except for the lower customer charge. While option 8 has bill impacts ranging from -10% to +22%, option 23 has bill impacts ranging from -50% to +21% and option 29 has impacts ranging from -38% to +21%. Estimated reductions in usage are comparable for the three cases.

FortisBC also notes that the block differential goes down when lower customer charges are implemented. For option 8 the rate differential is 44% while for option 23 it is only 19% and for option 29 it is 24%. While in all three cases the upper block is roughly 11 cents, the block 1 energy rate is 7.8 cents for option 8 compared to 9.3 cents for option 23 and 8.9 cents for option 29. These block 1 energy rates are close to or above the current flat block energy rate of 9.09 cents.

One reason FortisBC did not propose a lower customer charge along with the RIB rate was because both changes have similar bill impacts and when implemented together exaggerate bills impacts and reduce the block differential.

Options 21 and 24, with a lower customer charge of $10 and flat energy rates, result in roughly half of the energy savings as preferred option 8.

The impacts associated with lowering the customer charges highlights the issue raised in Commission Panel request 2.2, which questions the effectiveness of rates that have lower bills for a large number of customers. Any time that a lower customer charge or RIB rate is introduced, customers with low consumption levels will have reduced bills and a lower effective rate, with the adverse incentive to increase consumption levels.

## Table BCUC IR2 Q1.1a

| Option | Criterion | Threshold | Customer Charge | Block 1 Rate | Block 2 Rate | Block Differential | Annual Breakeven kWh | Percentage of customers better off | Maximum Bill Impact | Percentage of Customers with Bill Increases > 20% | Percentage of customers who have consumption in the second block at least once | Percentage of load billed in Block 2 | Conservation Impact (-lower/upper) | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | | | | | | | | | | | | | .05/.10 | .10/.20 | .20/.30 |
| 1 | 90% see <10% | 1350 | 28.93 | 0.06708 | 0.12208 | 82.0% | 13,500 | 70.7% | 32.4% | 2.7% | 79.2% | 43.3% | 2.8% | 5.6% | 8.3% |
| 2 | 95% see <10% | 1350 | 28.93 | 0.07526 | 0.11138 | 48.0% | 13,500 | 70.7% | 21.3% | 0.1% | 79.2% | 43.3% | 1.9% | 3.7% | 5.5% |
| 3 | 100% see <10% | 1350 | 28.93 | 0.08365 | 0.10039 | 20.0% | 13,500 | 70.7% | 9.9% | 0.0% | 79.2% | 43.3% | 0.9% | 1.7% | 2.5% |
| 4 | 90% see <10% | 2100 | 28.93 | 0.07454 | 0.13641 | 83.0% | 16,000 | 78.7% | 46.9% | 4.2% | 60.7% | 26.4% | 3.3% | 6.6% | 9.7% |
| 5 | 95% see <10% | 2100 | 28.93 | 0.08181 | 0.11618 | 42.0% | 16,000 | 78.7% | 26.0% | 0.4% | 60.7% | 26.4% | 1.8% | 3.7% | 5.4% |
| 6 | 100% see <10% | 2100 | 28.93 | 0.08743 | 0.10055 | 15.0% | 16,000 | 78.7% | 9.9% | 0.0% | 60.7% | 26.4% | 0.7% | 1.4% | 2.1% |
| 7 | 90% see <10% | 1600 | 28.93 | 0.07069 | 0.12584 | 78.0% | 15,000 | 75.7% | 36.2% | 2.7% | 72.8% | 36.6% | 3.0% | 6.0% | 8.8% |
| 8 | 95% see <10% | 1600 | 28.93 | 0.07828 | 0.11272 | 44.0% | 15,000 | 75.7% | 22.6% | 0.2% | 72.8% | 36.6% | 1.9% | 3.7% | 5.5% |
| 9 | 100% see <10% | 1600 | 28.93 | 0.08557 | 0.10012 | 17.0% | 14,000 | 72.5% | 9.6% | 0.0% | 72.8% | 36.6% | 0.8% | 1.6% | 2.3% |
| 10 | 90% see <10% | 1350 | 21.50 | 0.07391 | 0.12121 | 64.0% | 13,500 | 70.7% | 31.6% | 1.9% | 79.2% | 43.3% | 2.8% | 5.6% | 8.2% |
| 11 | 95% see <10% | 1350 | 21.50 | 0.08197 | 0.11066 | 35.0% | 13,500 | 70.7% | 20.6% | 0.1% | 79.2% | 43.3% | 1.8% | 3.7% | 5.4% |
| 12 | 100% see <10% | 1350 | 21.50 | 0.09010 | 0.10001 | 11.0% | 13,500 | 70.7% | 9.5% | 0.0% | 79.2% | 43.3% | 0.9% | 1.7% | 2.6% |
| 13 | 90% see <10% | 2100 | 21.50 | 0.08037 | 0.13341 | 66.0% | 16,000 | 78.7% | 43.8% | 2.7% | 60.7% | 26.4% | 3.2% | 6.4% | 9.4% |
| 14 | 95% see <10% | 2100 | 21.50 | 0.08703 | 0.11488 | 32.0% | 15,500 | 77.3% | 24.7% | 0.4% | 60.7% | 26.4% | 1.8% | 3.6% | 5.4% |
| 15 | 100% see <10% | 2100 | 21.50 | 0.09220 | 0.10050 | 9.0% | 14,000 | 72.5% | 9.9% | 0.0% | 60.7% | 26.4% | 0.8% | 1.5% | 2.3% |
| 16 | 90% see <10% | 1600 | 21.50 | 0.07715 | 0.12421 | 61.0% | 14,000 | 72.5% | 34.6% | 2.7% | 72.8% | 36.6% | 2.9% | 5.8% | 8.6% |
| 17 | 95% see <10% | 1600 | 21.50 | 0.08449 | 0.11152 | 33.0% | 14,000 | 72.5% | 21.4% | 0.1% | 72.8% | 36.6% | 1.8% | 3.6% | 5.4% |
| 18 | 100% see <10% | 1600 | 21.50 | 0.09106 | 0.10016 | 10.0% | 13,500 | 70.7% | 9.6% | 0.0% | 72.8% | 36.6% | 0.8% | 1.7% | 2.5% |
| 19 | 90% see <10% | 1350 | 10.00 | 0.08413 | 0.12031 | 43.0% | 13,500 | 70.7% | 30.6% | 1.3% | 79.2% | 43.3% | 2.5% | 5.0% | 7.4% |
| 20 | 95% see <10% | 1350 | 10.00 | 0.09184 | 0.11021 | 20.0% | 13,000 | 68.8% | 20.1% | 0.0% | 79.2% | 43.3% | 1.7% | 3.4% | 5.1% |
| 21 | 100% see <10% | 1350 | 10.00 | 0.09980 | 0.09980 | 0.0% | 13,000 | 68.8% | 9.3% | 0.0% | 79.2% | 43.3% | 0.9% | 1.8% | 2.7% |
| 22 | 90% see <10% | 1600 | 10.00 | 0.08650 | 0.12283 | 42.0% | 14,000 | 72.5% | 33.2% | 1.9% | 72.8% | 36.6% | 2.5% | 5.0% | 7.4% |
| 23 | 95% see <10% | 1600 | 10.00 | 0.09331 | 0.11104 | 19.0% | 13,500 | 70.7% | 21.0% | 0.0% | 72.8% | 36.6% | 1.6% | 3.3% | 5.0% |
| 24 | 100% see <10% | 1600 | 10.00 | 0.09980 | 0.09980 | 0.0% | 13,000 | 68.8% | 9.3% | 0.0% | 72.8% | 36.6% | 0.8% | 1.7% | 2.7% |
| 25 | 90% see <10% | 1350 | 15.00 | 0.07982 | 0.12053 | 51.0% | 13,500 | 70.7% | 30.9% | 1.9% | 79.2% | 43.3% | 2.5% | 4.9% | 7.2% |
| 26 | 95% see <10% | 1350 | 15.00 | 0.08759 | 0.11036 | 26.0% | 13,500 | 70.7% | 20.3% | 0.1% | 79.2% | 43.3% | 1.7% | 3.3% | 4.9% |
| 27 | 100% see <10% | 1350 | 15.00 | 0.09498 | 0.10068 | 6.0% | 13,500 | 70.7% | 9.2% | 0.0% | 79.2% | 43.3% | 0.9% | 1.8% | 2.7% |
| 28 | 90% see <10% | 1600 | 15.00 | 0.08237 | 0.12356 | 50.0% | 14,000 | 72.5% | 33.9% | 2.7% | 72.8% | 36.6% | 2.5% | 5.0% | 7.3% |
| 29 | 95% see <10% | 1600 | 15.00 | 0.08958 | 0.11108 | 24.0% | 13,500 | 70.7% | 21.0% | 0.1% | 72.8% | 36.6% | 1.6% | 3.2% | 4.8% |
| 30 | 100% see <10% | 1600 | 15.00 | 0.09604 | 0.09988 | 4.0% | 13,000 | 68.8% | 9.4% | 0.0% | 72.8% | 36.6% | 0.8% | 1.6% | 2.5% |

# Table BCUC IR2 Q1.1b

| | | | **Option** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | **Criterion** | 90% see <10% | 95% see <10% | 100% see <10% | 90% see <10% | 95% see <10% | 100% see <10% | 90% see <10% | 95% see <10% | 100% see <10% | 90% see <10% | 95% see <10% | 100% see <10% | 90% see <10% | 95% see <10% | 100% see <10% | 90% see <10% | 95% see <10% | 100% see <10% |
| | | | **Threshold** | 1350 | 1350 | 1350 | 2100 | 2100 | 2100 | 1600 | 1600 | 1600 | 1350 | 1350 | 1350 | 2100 | 2100 | 2100 | 1600 | 1600 | 1600 |
| | | | **Customer Charge** | $28.93 | $28.93 | $28.93 | $28.93 | $28.93 | $28.93 | $28.93 | $28.93 | $28.93 | $21.50 | $21.50 | $21.50 | $21.50 | $21.50 | $21.50 | $21.50 | $21.50 | $21.50 |
| **Annual Usage From (kWh)** | **To** | **# of Bills** | **Cumulative % of Bills** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** | **% Change** |
| 0 | 500 | 1,379 | 1.6% | -5.7% | -3.7% | -1.7% | -3.9% | -2.2% | -0.8% | -4.8% | -3.0% | -1.3% | -24.2% | -22.3% | -20.3% | -22.6% | -21.1% | -19.8% | -23.4% | -21.7% | -20.1% |
| 500 | 1,000 | 1,146 | 2.9% | -9.7% | -6.4% | -2.9% | -6.6% | -3.7% | -1.4% | -8.2% | -5.1% | -2.2% | -23.1% | -19.8% | -16.5% | -20.5% | -17.8% | -15.7% | -21.8% | -18.8% | -16.1% |
| 1,000 | 1,500 | 1,240 | 4.3% | -10.9% | -7.2% | -3.3% | -7.5% | -4.2% | -1.6% | -9.2% | -5.8% | -2.4% | -22.8% | -19.1% | -15.4% | -19.8% | -16.8% | -14.4% | -21.3% | -17.9% | -14.9% |
| 1,500 | 2,000 | 1,498 | 6.0% | -13.7% | -9.0% | -4.2% | -9.4% | -5.2% | -2.0% | -11.6% | -7.3% | -3.1% | -22.0% | -17.4% | -12.7% | -18.3% | -14.5% | -11.5% | -20.2% | -15.9% | -12.1% |
| 2,000 | 2,500 | 1,634 | 7.9% | -15.8% | -10.4% | -4.8% | -10.9% | -6.0% | -2.3% | -13.4% | -8.4% | -3.5% | -21.4% | -16.1% | -10.7% | -17.2% | -12.7% | -9.3% | -19.3% | -14.4% | -10.1% |
| 2,500 | 3,000 | 1,902 | 10.1% | -16.7% | -11.0% | -5.1% | -11.7% | -6.5% | -2.5% | -14.3% | -8.9% | -3.8% | -20.9% | -15.2% | -9.6% | -16.5% | -11.8% | -8.1% | -18.8% | -13.6% | -8.9% |
| 3,000 | 3,500 | 2,294 | 12.7% | -16.4% | -10.8% | -5.0% | -11.3% | -6.3% | -2.4% | -14.0% | -8.7% | -3.7% | -21.3% | -15.7% | -10.1% | -16.8% | -12.2% | -8.7% | -19.1% | -14.0% | -9.5% |
| 3,500 | 4,000 | 2,525 | 15.6% | -16.4% | -10.8% | -5.0% | -11.8% | -6.5% | -2.5% | -14.2% | -8.9% | -3.7% | -20.1% | -14.6% | -9.0% | -16.1% | -11.3% | -7.6% | -18.2% | -13.0% | -8.4% |
| 4,000 | 4,500 | 2,741 | 18.7% | -17.6% | -11.5% | -5.3% | -12.4% | -6.9% | -2.6% | -15.1% | -9.4% | -4.0% | -20.3% | -14.3% | -8.3% | -15.8% | -10.7% | -6.8% | -18.0% | -12.5% | -7.6% |
| 4,500 | 5,000 | 3,003 | 22.1% | -18.3% | -12.0% | -5.6% | -12.7% | -7.1% | -2.7% | -15.7% | -9.8% | -4.1% | -20.5% | -14.3% | -8.1% | -15.7% | -10.5% | -6.5% | -18.1% | -12.5% | -7.4% |
| 5,000 | 5,500 | 3,105 | 25.7% | -18.5% | -12.1% | -5.6% | -13.1% | -7.3% | -2.8% | -16.0% | -10.0% | -4.2% | -19.9% | -13.7% | -7.4% | -15.3% | -10.0% | -5.8% | -17.7% | -11.9% | -6.7% |
| 5,500 | 6,000 | 3,120 | 29.2% | -18.3% | -12.0% | -5.6% | -13.2% | -7.4% | -2.8% | -16.2% | -10.1% | -4.3% | -19.7% | -13.5% | -7.3% | -15.3% | -9.9% | -5.7% | -17.8% | -11.9% | -6.6% |
| 6,000 | 6,500 | 2,976 | 32.6% | -17.1% | -11.3% | -5.2% | -12.8% | -7.1% | -2.7% | -15.4% | -9.6% | -4.1% | -18.1% | -12.3% | -6.4% | -14.4% | -9.1% | -5.1% | -16.5% | -10.9% | -5.9% |
| 6,500 | 7,000 | 3,090 | 36.2% | -15.5% | -10.2% | -4.7% | -12.6% | -7.0% | -2.7% | -14.2% | -8.9% | -3.7% | -15.8% | -10.6% | -5.3% | -13.4% | -8.2% | -4.2% | -14.6% | -9.5% | -4.9% |
| 7,000 | 7,500 | 3,093 | 39.7% | -16.5% | -10.9% | -5.0% | -13.4% | -7.5% | -2.8% | -15.4% | -9.6% | -4.1% | -16.6% | -11.0% | -5.3% | -13.9% | -8.4% | -4.2% | -15.5% | -9.9% | -4.9% |
| 7,500 | 8,000 | 2,821 | 42.9% | -16.0% | -10.5% | -4.9% | -14.1% | -7.8% | -3.0% | -15.6% | -9.7% | -4.1% | -15.7% | -10.3% | -4.8% | -14.0% | -8.3% | -3.8% | -15.3% | -9.6% | -4.5% |
| 8,000 | 8,500 | 2,676 | 46.0% | -15.8% | -10.4% | -4.8% | -14.0% | -7.8% | -3.0% | -15.5% | -9.7% | -4.1% | -15.5% | -10.1% | -4.7% | -13.9% | -8.2% | -3.8% | -15.2% | -9.5% | -4.5% |
| 8,500 | 9,000 | 2,642 | 49.0% | -13.5% | -8.8% | -4.1% | -13.0% | -7.2% | -2.8% | -13.6% | -8.5% | -3.6% | -13.0% | -8.5% | -3.9% | -12.6% | -7.3% | -3.2% | -13.1% | -8.1% | -3.7% |
| 9,000 | 9,500 | 2,599 | 52.0% | -12.7% | -8.3% | -3.9% | -13.5% | -7.5% | -2.9% | -13.7% | -8.6% | -3.6% | -12.1% | -7.8% | -3.5% | -12.8% | -7.3% | -3.0% | -12.9% | -7.9% | -3.4% |
| 9,500 | 10,000 | 2,482 | 54.8% | -9.9% | -6.5% | -3.0% | -11.5% | -6.4% | -2.4% | -11.3% | -7.1% | -3.0% | -9.5% | -6.2% | -2.8% | -10.9% | -6.2% | -2.5% | -10.7% | -6.6% | -2.9% |
| 10,000 | 10,500 | 2,282 | 57.4% | -9.3% | -6.1% | -2.8% | -11.8% | -6.6% | -2.5% | -10.9% | -6.8% | -2.9% | -8.9% | -5.8% | -2.6% | -11.0% | -6.2% | -2.5% | -10.2% | -6.2% | -2.7% |
| 10,500 | 11,000 | 2,196 | 59.9% | -6.5% | -4.3% | -2.0% | -9.3% | -5.2% | -2.0% | -8.1% | -5.0% | -2.1% | -6.2% | -4.0% | -1.7% | -8.6% | -4.8% | -1.8% | -7.4% | -4.5% | -1.9% |
| 11,000 | 11,500 | 2,131 | 62.4% | -4.6% | -3.0% | -1.4% | -8.4% | -4.7% | -1.8% | -6.2% | -3.8% | -1.6% | -4.3% | -2.7% | -1.2% | -7.6% | -4.1% | -1.5% | -5.6% | -3.3% | -1.3% |
| 11,500 | 12,000 | 1,961 | 64.6% | -3.8% | -2.5% | -1.1% | -8.5% | -4.7% | -1.8% | -5.4% | -3.4% | -1.4% | -3.4% | -2.1% | -0.9% | -7.5% | -4.0% | -1.3% | -4.8% | -2.8% | -1.1% |
| 12,000 | 12,500 | 1,922 | 66.8% | -3.8% | -2.5% | -1.2% | -8.8% | -4.9% | -1.9% | -5.4% | -3.4% | -1.4% | -3.4% | -2.1% | -0.8% | -7.7% | -4.1% | -1.3% | -4.8% | -2.8% | -1.0% |
| 12,500 | 13,000 | 1,728 | 68.8% | -3.8% | -2.5% | -1.2% | -8.8% | -4.9% | -1.9% | -5.5% | -3.4% | -1.5% | -3.4% | -2.1% | -0.8% | -7.7% | -4.1% | -1.3% | -4.9% | -2.9% | -1.1% |
| 13,000 | 13,500 | 1,665 | 70.7% | -1.4% | -0.9% | -0.4% | -7.1% | -4.0% | -1.5% | -3.3% | -2.0% | -0.9% | -1.0% | -0.6% | -0.1% | -5.9% | -3.0% | -0.8% | -2.6% | -1.4% | -0.4% |
| 13,500 | 14,000 | 1,583 | 72.5% | 0.0% | 0.0% | 0.0% | -3.6% | -2.0% | -0.8% | -1.2% | -0.8% | -0.3% | 0.2% | 0.2% | 0.2% | -2.9% | -1.4% | -0.2% | -0.8% | -0.4% | 0.0% |
| 14,000 | 14,500 | 1,458 | 74.2% | 2.2% | 1.4% | 0.7% | -1.7% | -0.9% | -0.4% | 1.1% | 0.7% | 0.3% | 2.4% | 1.7% | 0.9% | -0.9% | -0.2% | 0.3% | 1.5% | 1.1% | 0.7% |
| 14,500 | 15,000 | 1,380 | 75.7% | 1.2% | 0.8% | 0.3% | -3.3% | -1.8% | -0.7% | -0.2% | -0.1% | -0.1% | 1.3% | 1.0% | 0.6% | -2.5% | -1.1% | -0.1% | 0.2% | 0.2% | 0.3% |
| 15,000 | 15,500 | 1,348 | 77.3% | 1.8% | 1.2% | 0.6% | -2.5% | -1.4% | -0.5% | 0.6% | 0.4% | 0.2% | 2.0% | 1.4% | 0.8% | -1.7% | -0.7% | 0.1% | 1.0% | 0.8% | 0.6% |
| 15,500 | 16,000 | 1,266 | 78.7% | 3.3% | 2.1% | 1.0% | -1.1% | -0.6% | -0.2% | 2.1% | 1.3% | 0.6% | 3.5% | 2.4% | 1.2% | -0.2% | 0.2% | 0.5% | 2.5% | 1.7% | 1.0% |
| 16,000 | 16,500 | 1,229 | 80.1% | 3.1% | 2.1% | 1.0% | 0.3% | 0.1% | 0.1% | 2.3% | 1.4% | 0.6% | 3.3% | 2.2% | 1.1% | 0.8% | 0.7% | 0.6% | 2.5% | 1.7% | 0.9% |
| 16,500 | 17,000 | 1,041 | 81.3% | 5.1% | 3.3% | 1.6% | 1.0% | 0.5% | 0.2% | 4.0% | 2.5% | 1.1% | 5.3% | 3.5% | 1.8% | 1.7% | 1.3% | 1.0% | 4.3% | 2.9% | 1.5% |
| 17,000 | 18,000 | 1,961 | 83.6% | 6.1% | 4.0% | 1.9% | 3.5% | 1.9% | 0.7% | 5.4% | 3.4% | 1.4% | 6.2% | 4.1% | 2.0% | 3.9% | 2.5% | 1.4% | 5.6% | 3.6% | 1.8% |
| 18,000 | 19,000 | 1,674 | 85.5% | 7.0% | 4.6% | 2.1% | 5.2% | 2.9% | 1.1% | 6.7% | 4.2% | 1.8% | 7.0% | 4.6% | 2.2% | 5.4% | 3.3% | 1.7% | 6.7% | 4.3% | 2.1% |
| 19,000 | 20,000 | 1,454 | 87.1% | 8.3% | 5.5% | 2.5% | 7.2% | 4.0% | 1.5% | 8.0% | 5.0% | 2.1% | 8.4% | 5.5% | 2.7% | 7.4% | 4.4% | 2.2% | 8.1% | 5.1% | 2.5% |
| 20,000 | 21,000 | 1,290 | 88.6% | 9.8% | 6.4% | 3.0% | 8.3% | 4.6% | 1.8% | 9.5% | 5.9% | 2.5% | 9.7% | 6.4% | 3.1% | 8.5% | 5.1% | 2.4% | 9.4% | 6.0% | 2.9% |
| 21,000 | 22,000 | 1,157 | 89.9% | 9.9% | 6.5% | 3.0% | 9.9% | 5.5% | 2.1% | 9.9% | 6.2% | 2.6% | 9.9% | 6.5% | 3.1% | 9.8% | 5.8% | 2.7% | 9.8% | 6.2% | 3.0% |
| 22,000 | 24,000 | 1,831 | 92.0% | 12.4% | 8.1% | 3.8% | 13.1% | 7.3% | 2.8% | 12.7% | 7.9% | 3.3% | 12.3% | 8.1% | 3.8% | 12.9% | 7.5% | 3.4% | 12.4% | 7.8% | 3.7% |
| 24,000 | 26,000 | 1,367 | 93.6% | 13.3% | 8.7% | 4.0% | 15.2% | 8.4% | 3.2% | 13.9% | 8.7% | 3.7% | 13.1% | 8.6% | 4.1% | 14.7% | 8.5% | 3.7% | 13.5% | 8.5% | 4.0% |
| 26,000 | 28,000 | 1,070 | 94.8% | 15.1% | 9.9% | 4.6% | 17.6% | 9.8% | 3.7% | 15.9% | 9.9% | 4.2% | 14.9% | 9.8% | 4.6% | 17.0% | 9.8% | 4.3% | 15.5% | 9.7% | 4.5% |
| 28,000 | 30,000 | 843 | 95.8% | 15.7% | 10.3% | 4.8% | 18.6% | 10.3% | 3.9% | 16.5% | 10.3% | 4.4% | 15.4% | 10.1% | 4.7% | 17.8% | 10.3% | 4.4% | 16.0% | 10.0% | 4.6% |
| 30,000 | 35,000 | 1,339 | 97.3% | 16.4% | 10.8% | 5.0% | 20.6% | 11.5% | 4.4% | 17.6% | 11.0% | 4.6% | 16.0% | 10.5% | 4.9% | 19.6% | 11.2% | 4.7% | 16.9% | 10.5% | 4.8% |
| 35,000 | 40,000 | 728 | 98.1% | 20.2% | 13.3% | 6.2% | 26.4% | 14.6% | 5.6% | 21.9% | 13.7% | 5.8% | 19.8% | 12.9% | 6.0% | 25.0% | 14.2% | 5.9% | 21.1% | 13.1% | 6.0% |
| 40,000 | 45,000 | 461 | 98.7% | 21.7% | 14.3% | 6.6% | 28.5% | 15.8% | 6.0% | 23.6% | 14.7% | 6.2% | 21.2% | 13.9% | 6.5% | 27.0% | 15.4% | 6.4% | 22.7% | 14.1% | 6.5% |
| 45,000 | 50,000 | 275 | 99.0% | 23.4% | 15.4% | 7.1% | 31.3% | 17.4% | 6.6% | 25.5% | 16.0% | 6.7% | 22.8% | 14.9% | 6.9% | 29.6% | 16.8% | 6.9% | 24.5% | 15.3% | 7.0% |
| 50,000 | 60,000 | 339 | 99.4% | 25.1% | 16.5% | 7.6% | 34.3% | 19.1% | 7.3% | 27.6% | 17.2% | 7.3% | 24.5% | 16.0% | 7.4% | 32.3% | 18.4% | 7.5% | 26.5% | 16.4% | 7.5% |
| 60,000 | 70,000 | 192 | 99.6% | 26.0% | 17.1% | 7.9% | 35.8% | 19.9% | 7.6% | 28.6% | 17.9% | 7.5% | 25.3% | 16.6% | 7.7% | 33.7% | 19.1% | 7.8% | 27.4% | 17.0% | 7.7% |
| 70,000 | 80,000 | 112 | 99.7% | 27.1% | 17.8% | 8.2% | 37.7% | 20.9% | 8.0% | 29.9% | 18.7% | 7.9% | 26.4% | 17.2% | 8.0% | 35.4% | 20.1% | 8.2% | 28.6% | 17.8% | 8.0% |
| 80,000 | 90,000 | 64 | 99.8% | 27.6% | 18.1% | 8.4% | 38.5% | 21.4% | 8.2% | 30.5% | 19.0% | 8.0% | 26.9% | 17.5% | 8.1% | 36.2% | 20.5% | 8.3% | 29.2% | 18.1% | 8.2% |
| 90,000 | 100,000 | 47 | 99.8% | 28.6% | 18.8% | 8.7% | 40.3% | 22.4% | 8.5% | 31.7% | 19.8% | 8.4% | 27.9% | 18.2% | 8.4% | 37.8% | 21.4% | 8.7% | 30.3% | 18.8% | 8.5% |
| 100,000 | 150,000 | 88 | 99.9% | 29.6% | 19.5% | 9.0% | 42.1% | 23.4% | 8.9% | 32.9% | 20.6% | 8.7% | 28.9% | 18.8% | 8.7% | 39.4% | 22.3% | 9.0% | 31.5% | 19.5% | 8.8% |
| 150,000 | and over | 46 | 100.0% | 32.4% | 21.3% | 9.9% | 46.9% | 26.0% | 9.9% | 36.2% | 22.6% | 9.6% | 31.6% | 20.6% | 9.5% | 43.8% | 24.7% | 9.9% | 34.6% | 21.4% | 9.6% |

## Table BCUC IR2 Q1.1b, cont'd

| | | | Option | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Criterion | 90% see <10% | 95% see <10% | 100% see <10% | 90% see <10% | 95% see <10% | 100% see <10% | 90% see <10% | 95% see <10% | 100% see <10% | 90% see <10% | 95% see <10% | 100% see <10% |
| | | | Threshold | 1350 | 1350 | 1350 | 1600 | 1600 | 1600 | 1350 | 1350 | 1350 | 1600 | 1600 | 1600 |
| | | | Customer Charge | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $15.00 | $15.00 | $15.00 | $15.00 | $15.00 | $15.00 |
| Annual Usage From (kWh) | To | # of Bills | Cumulative % of Bills | % Change | % Change | % Change | % Change | % Change | % Change | % Change | % Change | % Change | % Change | % Change | % Change |
| 0 | 500 | 1,379 | 1.6% | -52.9% | -51.1% | -49.2% | -52.3% | -50.7% | -49.2% | -40.4% | -38.5% | -36.8% | -39.8% | -38.1% | -36.5% |
| 500 | 1,000 | 1,146 | 2.9% | -44.0% | -40.9% | -37.7% | -43.1% | -40.3% | -37.7% | -34.9% | -31.7% | -28.7% | -33.8% | -30.9% | -28.3% |
| 1,000 | 1,500 | 1,240 | 4.3% | -41.3% | -37.8% | -34.2% | -40.2% | -37.1% | -34.2% | -33.2% | -29.6% | -26.3% | -32.0% | -28.7% | -25.8% |
| 1,500 | 2,000 | 1,498 | 6.0% | -35.1% | -30.6% | -26.0% | -33.7% | -29.8% | -26.0% | -29.3% | -24.8% | -20.6% | -27.8% | -23.7% | -20.0% |
| 2,000 | 2,500 | 1,634 | 7.9% | -30.4% | -25.3% | -20.0% | -28.8% | -24.3% | -20.0% | -26.4% | -21.2% | -16.3% | -24.7% | -19.9% | -15.6% |
| 2,500 | 3,000 | 1,902 | 10.1% | -27.6% | -22.2% | -16.7% | -26.1% | -21.3% | -16.7% | -24.6% | -19.2% | -14.0% | -23.0% | -17.9% | -13.3% |
| 3,000 | 3,500 | 2,294 | 12.7% | -29.0% | -23.7% | -18.2% | -27.4% | -22.7% | -18.2% | -25.6% | -20.2% | -15.1% | -23.8% | -18.8% | -14.4% |
| 3,500 | 4,000 | 2,525 | 15.6% | -26.2% | -20.9% | -15.4% | -24.7% | -19.9% | -15.4% | -23.5% | -18.1% | -13.0% | -21.9% | -16.9% | -12.3% |
| 4,000 | 4,500 | 2,741 | 18.7% | -24.7% | -19.0% | -13.1% | -23.1% | -18.0% | -13.1% | -22.7% | -16.9% | -11.5% | -20.9% | -15.5% | -10.7% |
| 4,500 | 5,000 | 3,003 | 22.1% | -24.2% | -18.3% | -12.2% | -22.5% | -17.2% | -12.2% | -22.5% | -16.5% | -10.8% | -20.6% | -15.1% | -10.0% |
| 5,000 | 5,500 | 3,105 | 25.7% | -22.5% | -16.5% | -10.3% | -20.8% | -15.4% | -10.3% | -21.3% | -15.2% | -9.5% | -19.5% | -13.8% | -8.7% |
| 5,500 | 6,000 | 3,120 | 29.2% | -22.1% | -16.2% | -10.1% | -20.7% | -15.3% | -10.1% | -21.0% | -15.0% | -9.3% | -19.5% | -13.7% | -8.5% |
| 6,000 | 6,500 | 2,976 | 32.6% | -19.8% | -14.3% | -8.5% | -18.6% | -13.5% | -8.5% | -19.0% | -13.4% | -8.1% | -17.7% | -12.3% | -7.3% |
| 6,500 | 7,000 | 3,090 | 36.2% | -16.6% | -11.6% | -6.5% | -15.8% | -11.0% | -6.5% | -16.2% | -11.1% | -6.4% | -15.3% | -10.3% | -5.7% |
| 7,000 | 7,500 | 3,093 | 39.7% | -16.9% | -11.6% | -6.0% | -16.2% | -11.0% | -6.0% | -16.7% | -11.3% | -6.2% | -15.9% | -10.4% | -5.5% |
| 7,500 | 8,000 | 2,821 | 42.9% | -15.5% | -10.3% | -5.0% | -15.2% | -10.0% | -5.0% | -15.5% | -10.3% | -5.4% | -15.3% | -9.7% | -4.7% |
| 8,000 | 8,500 | 2,676 | 46.0% | -15.2% | -10.1% | -4.8% | -15.1% | -9.8% | -4.8% | -15.2% | -10.1% | -5.3% | -15.2% | -9.6% | -4.6% |
| 8,500 | 9,000 | 2,642 | 49.0% | -12.6% | -8.2% | -3.7% | -12.7% | -8.1% | -3.7% | -12.7% | -8.3% | -4.3% | -12.9% | -8.1% | -3.7% |
| 9,000 | 9,500 | 2,599 | 52.0% | -11.3% | -7.2% | -3.0% | -12.0% | -7.4% | -3.0% | -11.6% | -7.4% | -3.7% | -12.4% | -7.5% | -3.1% |
| 9,500 | 10,000 | 2,482 | 54.8% | -9.1% | -5.9% | -2.5% | -10.0% | -6.2% | -2.5% | -9.2% | -6.0% | -3.1% | -10.3% | -6.3% | -2.7% |
| 10,000 | 10,500 | 2,282 | 57.4% | -8.4% | -5.4% | -2.3% | -9.4% | -5.8% | -2.3% | -8.6% | -5.5% | -2.8% | -9.8% | -5.9% | -2.4% |
| 10,500 | 11,000 | 2,196 | 59.9% | -5.7% | -3.6% | -1.4% | -6.7% | -4.0% | -1.4% | -5.9% | -3.7% | -2.0% | -7.0% | -4.2% | -1.6% |
| 11,000 | 11,500 | 2,131 | 62.4% | -3.9% | -2.4% | -0.8% | -4.9% | -2.8% | -0.8% | -4.0% | -2.5% | -1.4% | -5.2% | -3.0% | -1.0% |
| 11,500 | 12,000 | 1,961 | 64.6% | -2.9% | -1.7% | -0.5% | -4.0% | -2.2% | -0.5% | -3.1% | -1.9% | -1.0% | -4.3% | -2.4% | -0.7% |
| 12,000 | 12,500 | 1,922 | 66.8% | -2.8% | -1.6% | -0.3% | -3.9% | -2.1% | -0.3% | -3.1% | -1.8% | -1.0% | -4.3% | -2.4% | -0.6% |
| 12,500 | 13,000 | 1,728 | 68.8% | -2.9% | -1.7% | -0.4% | -4.0% | -2.2% | -0.4% | -3.1% | -1.9% | -1.0% | -4.4% | -2.4% | -0.7% |
| 13,000 | 13,500 | 1,665 | 70.7% | -0.5% | 0.0% | 0.4% | -1.7% | -0.6% | 0.4% | -0.7% | -0.3% | -0.2% | -2.1% | -0.9% | 0.1% |
| 13,500 | 14,000 | 1,583 | 72.5% | 0.6% | 0.6% | 0.6% | -0.2% | 0.2% | 0.6% | 0.4% | 0.5% | 0.1% | -0.4% | 0.0% | 0.4% |
| 14,000 | 14,500 | 1,458 | 74.2% | 2.8% | 2.1% | 1.3% | 2.1% | 1.7% | 1.3% | 2.6% | 1.9% | 0.8% | 1.8% | 1.4% | 1.1% |
| 14,500 | 15,000 | 1,380 | 75.7% | 1.7% | 1.3% | 0.9% | 0.8% | 0.8% | 0.9% | 1.5% | 1.2% | 0.4% | 0.5% | 0.6% | 0.7% |
| 15,000 | 15,500 | 1,348 | 77.3% | 2.3% | 1.7% | 1.1% | 1.6% | 1.3% | 1.1% | 2.2% | 1.6% | 0.6% | 1.3% | 1.1% | 0.9% |
| 15,500 | 16,000 | 1,266 | 78.7% | 3.8% | 2.8% | 1.7% | 3.1% | 2.4% | 1.7% | 3.7% | 2.6% | 1.1% | 2.8% | 2.1% | 1.4% |
| 16,000 | 16,500 | 1,229 | 80.1% | 3.5% | 2.5% | 1.5% | 3.0% | 2.2% | 1.5% | 3.4% | 2.4% | 0.9% | 2.8% | 2.0% | 1.2% |
| 16,500 | 17,000 | 1,041 | 81.3% | 5.6% | 3.9% | 2.2% | 4.9% | 3.5% | 2.2% | 5.4% | 3.8% | 1.7% | 4.7% | 3.2% | 1.9% |
| 17,000 | 18,000 | 1,961 | 83.6% | 6.4% | 4.4% | 2.4% | 6.0% | 4.2% | 2.4% | 6.3% | 4.3% | 1.9% | 5.9% | 3.9% | 2.1% |
| 18,000 | 19,000 | 1,674 | 85.5% | 7.1% | 4.8% | 2.5% | 6.9% | 4.7% | 2.5% | 7.0% | 4.7% | 2.0% | 6.8% | 4.5% | 2.3% |
| 19,000 | 20,000 | 1,454 | 87.1% | 8.5% | 5.8% | 3.1% | 8.4% | 5.6% | 3.1% | 8.4% | 5.7% | 2.6% | 8.3% | 5.4% | 2.8% |
| 20,000 | 21,000 | 1,290 | 88.6% | 9.8% | 6.6% | 3.4% | 9.7% | 6.4% | 3.4% | 9.7% | 6.5% | 2.9% | 9.6% | 6.2% | 3.2% |
| 21,000 | 22,000 | 1,157 | 89.9% | 9.9% | 6.7% | 3.4% | 9.9% | 6.6% | 3.4% | 9.8% | 6.6% | 2.9% | 9.9% | 6.4% | 3.2% |
| 22,000 | 24,000 | 1,831 | 92.0% | 12.2% | 8.2% | 4.1% | 12.4% | 8.1% | 4.1% | 12.2% | 8.1% | 3.6% | 12.5% | 7.9% | 3.9% |
| 24,000 | 26,000 | 1,367 | 93.6% | 13.0% | 8.7% | 4.2% | 13.4% | 8.7% | 4.2% | 13.0% | 8.6% | 3.9% | 13.5% | 8.5% | 4.1% |
| 26,000 | 28,000 | 1,070 | 94.8% | 14.8% | 9.9% | 4.8% | 15.3% | 9.9% | 4.8% | 14.8% | 9.8% | 4.4% | 15.4% | 9.7% | 4.7% |
| 28,000 | 30,000 | 843 | 95.8% | 15.1% | 10.0% | 4.8% | 15.7% | 10.1% | 4.8% | 15.1% | 10.0% | 4.5% | 15.9% | 10.0% | 4.7% |
| 30,000 | 35,000 | 1,339 | 97.3% | 15.7% | 10.4% | 4.9% | 16.5% | 10.5% | 4.9% | 15.7% | 10.4% | 4.6% | 16.7% | 10.5% | 4.8% |
| 35,000 | 40,000 | 728 | 98.1% | 19.3% | 12.8% | 6.0% | 20.5% | 13.1% | 6.0% | 19.4% | 12.8% | 5.8% | 20.8% | 13.0% | 6.0% |
| 40,000 | 45,000 | 461 | 98.7% | 20.8% | 13.8% | 6.5% | 22.1% | 14.1% | 6.5% | 20.9% | 13.8% | 6.2% | 22.4% | 14.0% | 6.5% |
| 45,000 | 50,000 | 275 | 99.0% | 22.3% | 14.8% | 7.0% | 23.8% | 15.2% | 7.0% | 22.4% | 14.8% | 6.7% | 24.2% | 15.1% | 6.9% |
| 50,000 | 60,000 | 339 | 99.4% | 23.9% | 15.8% | 7.4% | 25.6% | 16.3% | 7.4% | 24.0% | 15.9% | 7.2% | 26.1% | 16.2% | 7.4% |
| 60,000 | 70,000 | 192 | 99.6% | 24.7% | 16.3% | 7.6% | 26.5% | 16.8% | 7.6% | 24.9% | 16.4% | 7.4% | 27.0% | 16.8% | 7.6% |
| 70,000 | 80,000 | 112 | 99.7% | 25.7% | 17.0% | 7.9% | 27.6% | 17.5% | 7.9% | 25.9% | 17.0% | 7.7% | 28.2% | 17.5% | 7.9% |
| 80,000 | 90,000 | 64 | 99.8% | 26.2% | 17.3% | 8.0% | 28.1% | 17.9% | 8.0% | 26.3% | 17.3% | 7.9% | 28.7% | 17.8% | 8.0% |
| 90,000 | 100,000 | 47 | 99.8% | 27.1% | 17.9% | 8.3% | 29.2% | 18.5% | 8.3% | 27.3% | 18.0% | 8.1% | 29.8% | 18.5% | 8.3% |
| 100,000 | 150,000 | 88 | 99.9% | 28.1% | 18.5% | 8.6% | 30.3% | 19.2% | 8.6% | 28.3% | 18.6% | 8.4% | 30.9% | 19.2% | 8.6% |
| 150,000 | and over | 46 | 100.0% | 30.6% | 20.1% | 9.3% | 33.2% | 21.0% | 9.3% | 30.9% | 20.3% | 9.2% | 33.9% | 21.0% | 9.4% |

1.2 Regardless of the outcome of the initial screening analysis, please conduct an additional suitability test by applying pricing principles E/G and F/H for Options 19 to 30 and provide the projected results for the 2011 to 2015 period consistent with Table 8-3. (Pricing Principle Reference: Exhibit B—5, BCUC 1.5.1(b))

**Response:**

Please find the requested results in Table BCUC IR2 Q1.2 below.

To be clear, a brief summary of escalation methods used in scenarios E/G and F/H appears below. These principles are different than that described in BCUC 1.5.1, which is FortisBC’s suggested escalation method.

| | |
|---|---|
| Escalation Method E/G | Customer Charge – escalated annually by the sum of the general rate increase and the rebalancing increase.<br><br>Block 1 Rate - escalated annually by the sum of the general rate increase and the rebalancing increase.<br><br>Block 2 Rate – escalated annually by the sum of the general rate increase and the rebalancing increase. |
| Escalation Method F/H | Customer Charge – escalated annually by the sum of the general rate increase and the rebalancing increase.<br><br>Block 1 Rate – not escalated<br><br>Block 2 Rate – calculated residually to ensure recovery of the revenue requirement. |

# Table BCUC IR2 Q1.2

| Pricing Principle | Base Rate Option | Threshold | Rate Increase Applied | | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Rate Increase* | | 8.90% | 6.50% | 3.40% | 6.50% |
| E/G | 19 | 1350 | All Components | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.08413 | 0.09162 | 0.09758 | 0.10089 | 0.10745 |
| | | | | Block 2 Rate | 0.12031 | 0.13102 | 0.13953 | 0.14428 | 0.15366 |
| | | | | Ratio: Block 2 / Block 1 | 1.43 | 1.43 | 1.43 | 1.43 | 1.43 |
| F/H | 19 | 1350 | Customer Charge and Block 2 | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.08413 | 0.08413 | 0.08413 | 0.08413 | 0.08413 |
| | | | | Block 2 Rate | 0.12031 | 0.14082 | 0.15713 | 0.16622 | 0.18418 |
| | | | | Ratio: Block 2 / Block 1 | 1.43 | 1.67 | 1.87 | 1.98 | 2.19 |
| E/G | 20 | 1350 | All Components | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.09184 | 0.10002 | 0.10652 | 0.11014 | 0.11730 |
| | | | | Block 2 Rate | 0.11021 | 0.12002 | 0.12782 | 0.13217 | 0.14076 |
| | | | | Ratio: Block 2 / Block 1 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 |
| F/H | 20 | 1350 | Customer Charge and Block 2 | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.09184 | 0.09184 | 0.09184 | 0.09184 | 0.09184 |
| | | | | Block 2 Rate | 0.11021 | 0.13072 | 0.14704 | 0.15612 | 0.17409 |
| | | | | Ratio: Block 2 / Block 1 | 1.20 | 1.42 | 1.60 | 1.70 | 1.90 |
| E/G | 21 | 1350 | All Components | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.09980 | 0.10868 | 0.11574 | 0.11968 | 0.12746 |
| | | | | Block 2 Rate | 0.09980 | 0.10868 | 0.11574 | 0.11968 | 0.12746 |
| | | | | Ratio: Block 2 / Block 1 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| F/H | 21 | 1350 | Customer Charge and Block 2 | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.09980 | 0.09980 | 0.09980 | 0.09980 | 0.09980 |
| | | | | Block 2 Rate | 0.09980 | 0.12031 | 0.13662 | 0.14571 | 0.16367 |
| | | | | Ratio: Block 2 / Block 1 | 1.00 | 1.21 | 1.37 | 1.46 | 1.64 |
| E/G | 22 | 1600 | All Components | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.08650 | 0.09420 | 0.10032 | 0.10373 | 0.11048 |
| | | | | Block 2 Rate | 0.12283 | 0.13376 | 0.14246 | 0.14730 | 0.15688 |
| | | | | Ratio: Block 2 / Block 1 | 1.42 | 1.42 | 1.42 | 1.42 | 1.42 |
| F/H | 22 | 1600 | Customer Charge and Block 2 | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.08650 | 0.08650 | 0.08650 | 0.08650 | 0.08650 |
| | | | | Block 2 Rate | 0.12283 | 0.14708 | 0.16636 | 0.17710 | 0.19833 |
| | | | | Ratio: Block 2 / Block 1 | 1.42 | 1.70 | 1.92 | 2.05 | 2.29 |
| E/G | 23 | 1600 | All Components | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.09331 | 0.10161 | 0.10822 | 0.11190 | 0.11917 |
| | | | | Block 2 Rate | 0.11104 | 0.12092 | 0.12878 | 0.13316 | 0.14181 |
| | | | | Ratio: Block 2 / Block 1 | 1.19 | 1.19 | 1.19 | 1.19 | 1.19 |
| F/H | 23 | 1600 | Customer Charge and Block 2 | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.09331 | 0.09331 | 0.09331 | 0.09331 | 0.09331 |
| | | | | Block 2 Rate | 0.11104 | 0.13528 | 0.15456 | 0.16530 | 0.18653 |
| | | | | Ratio: Block 2 / Block 1 | 1.19 | 1.45 | 1.66 | 1.77 | 2.00 |
| E/G | 24 | 1600 | All Components | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.09980 | 0.10868 | 0.11574 | 0.11968 | 0.12746 |
| | | | | Block 2 Rate | 0.09980 | 0.10868 | 0.11574 | 0.11968 | 0.12746 |
| | | | | Ratio: Block 2 / Block 1 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| F/H | 24 | 1600 | Customer Charge and Block 2 | Customer Charge | 10.00 | 10.89 | 11.60 | 11.99 | 12.77 |
| | | | | Block 1 Rate | 0.09980 | 0.09980 | 0.09980 | 0.09980 | 0.09980 |
| | | | | Block 2 Rate | 0.09980 | 0.12404 | 0.14332 | 0.15406 | 0.17529 |
| | | | | Ratio: Block 2 / Block 1 | 1.00 | 1.24 | 1.44 | 1.54 | 1.76 |
| E/G | 25 | 1350 | All Components | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.07982 | 0.08693 | 0.09258 | 0.09572 | 0.10194 |
| | | | | Block 2 Rate | 0.12053 | 0.13126 | 0.13979 | 0.14454 | 0.15394 |
| | | | | Ratio: Block 2 / Block 1 | 1.51 | 1.51 | 1.51 | 1.51 | 1.51 |
| F/H | 25 | 1350 | Customer Charge and Block 2 | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.07982 | 0.07982 | 0.07982 | 0.07982 | 0.07982 |
| | | | | Block 2 Rate | 0.12053 | 0.14056 | 0.15649 | 0.16536 | 0.18290 |
| | | | | Ratio: Block 2 / Block 1 | 1.51 | 1.76 | 1.96 | 2.07 | 2.29 |
| E/G | 26 | 1350 | All Components | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.08759 | 0.09538 | 0.10158 | 0.10504 | 0.11186 |
| | | | | Block 2 Rate | 0.11036 | 0.12018 | 0.12799 | 0.13235 | 0.14095 |
| | | | | Ratio: Block 2 / Block 1 | 1.26 | 1.26 | 1.26 | 1.26 | 1.26 |
| F/H | 26 | 1350 | Customer Charge and Block 2 | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.08759 | 0.08759 | 0.08759 | 0.08759 | 0.08759 |
| | | | | Block 2 Rate | 0.11036 | 0.13039 | 0.14632 | 0.15519 | 0.17273 |
| | | | | Ratio: Block 2 / Block 1 | 1.26 | 1.49 | 1.67 | 1.77 | 1.97 |
| E/G | 27 | 1350 | All Components | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.09498 | 0.10343 | 0.11016 | 0.11390 | 0.12131 |
| | | | | Block 2 Rate | 0.10068 | 0.10964 | 0.11677 | 0.12074 | 0.12858 |
| | | | | Ratio: Block 2 / Block 1 | 1.06 | 1.06 | 1.06 | 1.06 | 1.06 |
| F/H | 27 | 1350 | Customer Charge and Block 2 | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.09498 | 0.09498 | 0.09498 | 0.09498 | 0.09498 |
| | | | | Block 2 Rate | 0.10068 | 0.12071 | 0.13663 | 0.14551 | 0.16305 |
| | | | | Ratio: Block 2 / Block 1 | 1.06 | 1.27 | 1.44 | 1.53 | 1.72 |
| E/G | 28 | 1600 | All Components | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.08237 | 0.08970 | 0.09554 | 0.09878 | 0.10520 |
| | | | | Block 2 Rate | 0.12356 | 0.13456 | 0.14330 | 0.14818 | 0.15781 |
| | | | | Ratio: Block 2 / Block 1 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |
| F/H | 28 | 1600 | Customer Charge and Block 2 | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.08237 | 0.08237 | 0.08237 | 0.08237 | 0.08237 |
| | | | | Block 2 Rate | 0.12356 | 0.14723 | 0.16606 | 0.17655 | 0.19728 |
| | | | | Ratio: Block 2 / Block 1 | 1.50 | 1.79 | 2.02 | 2.14 | 2.39 |
| E/G | 29 | 1600 | All Components | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.08958 | 0.09755 | 0.10389 | 0.10743 | 0.11441 |
| | | | | Block 2 Rate | 0.11108 | 0.12096 | 0.12883 | 0.13321 | 0.14187 |
| | | | | Ratio: Block 2 / Block 1 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 |
| F/H | 29 | 1600 | Customer Charge and Block 2 | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.08958 | 0.08958 | 0.08958 | 0.08958 | 0.08958 |
| | | | | Block 2 Rate | 0.11108 | 0.13475 | 0.15358 | 0.16406 | 0.18480 |
| | | | | Ratio: Block 2 / Block 1 | 1.24 | 1.50 | 1.71 | 1.83 | 2.06 |
| E/G | 30 | 1600 | All Components | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.09604 | 0.10459 | 0.11139 | 0.11518 | 0.12266 |
| | | | | Block 2 Rate | 0.09988 | 0.10877 | 0.11584 | 0.11978 | 0.12757 |
| | | | | Ratio: Block 2 / Block 1 | 1.04 | 1.04 | 1.04 | 1.04 | 1.04 |
| F/H | 30 | 1600 | Customer Charge and Block 2 | Customer Charge | 15.00 | 16.34 | 17.40 | 17.99 | 19.16 |
| | | | | Block 1 Rate | 0.09604 | 0.09604 | 0.09604 | 0.09604 | 0.09604 |
| | | | | Block 2 Rate | 0.09988 | 0.12355 | 0.14238 | 0.15287 | 0.17360 |
| | | | | Ratio: Block 2 / Block 1 | 1.04 | 1.29 | 1.48 | 1.59 | 1.81 |

1.3 Please select the top three options of these scenarios in terms of offering the optimal balance between price signal, conservation and customer bill impact and provide an assessment of how these options compare to the RIB rate proposed by FortisBC. Specifically, the Panel is seeking a discussion of pros and cons of these Options.

**Response:**

The Company has compared the new options 19-30 with respect to price signal, conservation and customer bill impact in order to arrive at the top three options from the group. Initially, those options with a block differential of less than 20% and greater than 60% were removed as per BCUC IR No. 1 Q9.8. After these options were removed, the remaining options were compared against those in the same group (same threshold and Customer Charge) with those options that in the opinion of the Company provided the best balance between the considerations being kept. This resulted in the three additional options in the table below remaining for comparison to the preferred option 8.

**Table BCUC IR2 Q1.3**

| Option | Criterion | Threshold | Customer Charge | Block 1 Rate | Block 2 Rate | Block Differential | Annual Breakeven kWh | Percentage of customers better off | Maximum Bill Impact | Percentage of Customers with Bill Increases > 20% | Percentage of customers who have consumption in the second block at least once | Percentage of load billed in Block 2 | Conservation Impact (-lower/upper) | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | | | | | | | | | | | | | .05/.010 | .10/.20 | .20/.30 |
| 8 | 95% see <10% | 1600 | 28.93 | 0.07828 | 0.11272 | 44.0% | 15000 | 75.7% | 22.6% | 0.2% | 72.8% | 36.6% | 1.9% | 3.7% | 5.5% |
| 19 | 90% see <10% | 1350 | 10.00 | 0.08413 | 0.12031 | 43.0% | 13500 | 70.7% | 30.6% | 1.3% | 79.2% | 43.3% | 2.5% | 5.0% | 7.4% |
| 22 | 90% see <10% | 1600 | 10.00 | 0.08650 | 0.12283 | 42.0% | 14000 | 72.5% | 33.2% | 1.9% | 72.8% | 36.6% | 2.5% | 5.0% | 7.4% |
| 25 | 90% see <10% | 1350 | 15.00 | 0.07982 | 0.12053 | 51.0% | 13500 | 70.7% | 30.9% | 1.9% | 79.2% | 43.3% | 2.5% | 4.9% | 7.2% |

These three options are all very close in terms of results. When compared to the original option 8, the pros and cons are as follows:

<u>Pros</u>

- Higher conservation impact at all assumed elasticity values
- For options 19 and 25, more load billed in block 2.

<u>Cons</u>

- Customer Charge even farther below COSA-derived level than option 8
- Lower percentage of customers are better off

- Higher maximum bill impact
- Higher percentage of customers with bill impact greater than 20%

**2.0 Reference: BC Hydro 2008 Residential Inclining Block Application, Section 3.2.2, pp. 3-2 and 3-3**

**Pricing Principles**

In its 2008 RIB rate filing BC Hydro introduced the following four "economic efficiency" tests to be considered in addition to the Bonbright Principles:

i. No customer should see a rate decrease, to avoid providing disincentives to conservation;
ii. As many customers as possible should see the Step-2 rate, maximize the number of customers that have incentives to conserve;
iii. The differential between the Step-1 rate and Step-2 rate should be sufficiently large to provide a meaningful incentive for conservation; and
iv. The Step-rate should be more reflective of, while not exceeding, the full cost of new supply (plus fixed costs), relative to the otherwise applicable flat rate, to incent more conservation than under a flat rate structure.

2.1 In reference to FortisBC responses to BCUC 1.9.2, 1.9.6, 1.9.8, 1.9.9 and 1.9.10, please further elaborate on the Company's views on these tests. This elaboration should at a minimum cover whether or not any of these tests should be considered a pass/fail test and how they can provide further guidance in incorporating efficient price signals into a residential rate structure.

**Response:**

Please see below the FortisBC response to the referenced tests:

i. In the scenarios examined by FortisBC, setting a floor price for the block 1 rate at the flat rate in effect at the time would result in a block rate differential that would provide little or no conservation incentive.

   To illustrate this fact, the Company has developed example rates based on keeping the block 1 charge at the current (at the time of the Application) flat rate of 0.9090 $ / kWh, using the 95% of customers experiencing no more than a 10% annual bill impact criterion, and the 1350 and 1600 kWh thresholds. If the Customer Charge is held at its current level the block 1 and block 2 rates cannot vary and remain equal. Therefore, for the analysis, a Customer Charge of $21.50 has been assumed.

For the 1350 kWh threshold, the resulting block 2 rate would be .09897 $/kWh for a differential of only 8.9%

For the 1600 kWh threshold, the resulting block 2 rate would be .1044 $/kWh for a differential of only 10.5%

Neither of these outcomes provides a conservation signal of note.

Additionally, according to BC Hydro's RIB Application (at Appendix A, Table A-7) it's proposed F2009 Step 1 and Step 2 rate were 6.28 and 6.98 cent/kWh respectively compared to the flat rate of 6.55 cents/kWh for all consumption. It would appear that the goal is one of minimizing the potential for sending the wrong price signal, rather than an absolute.

For this reason, the Company does not believe that this test should be pass/fail

ii. The Company believes that the number of customers who see the block 2 rate is a useful measure and has included it in its analysis for that reason. The Company does not view this as a pass/fail test as no minimum threshold for the measure has been established.

iii. FortisBC agrees that the block 1/ block 2 differential is important as an indicator of conservation potential and used this test during the initial screening of the options. It can be considered a pass/fail test for those values that are obviously too low or too high (as in the results presented in part i of this response), but as noted previously since the Company did not predetermine a acceptable minimum and maximum amount, it is not a pass/fail test for reasonable values but rather is a useful indicator when comparing options that are viable in consideration of the other tests.

iv. FortisBC discusses the pricing of the blocks in consideration of marginal costs in its response to Question 6.1 in this IR set and with the respect to the flat rate under part i.) FortisBC generally agrees that the relationship between the step 1 and step 2 rate should provide a price signal based on the higher cost of power at the margin and believes that the option it has presented in the Application accomplishes this. This requirement for the step 2 rate to be higher than the step 1 rate is a pass/fail test.

In as much as these tests can be indicative of the conservation potential of a proposed residential rate, they should continue to be calculated and balanced against the customer impact to provide guidance on the selection of rate options. None should be examined in isolation.

2.2 Please provide further justification on how the recommended Option 8, which appears to result in 27.2 % of customers facing absolute rate decreases, can be perceived as a conservation rate. (Reference Exhibit B-5, BCUC 1.3.5 and 1.9.6)

**Response:**

The choice of Option 8, with rate components escalated as in Case C of Table 8-3 was made after comparing it with the other scenarios that were modeled by the Company, primarily through looking at Table 7-2, and then assessing whether the proposed methods of escalation contained in Table 8-3 gave reason to re-examine the choice.

The Company considers a conservation rate to be one with a structure that contains a mechanism to provide a price signal to some portion of its customers, and on balance is estimated to provide some level of conservation from the customer class. It does not view it as a necessity that 100% of customers must see a signal that would drive conservation. Given that only two of the rate options modeled (15 and 18) have a block 1 rate higher than the flat rate, it is natural that most rates would allow for some portion of customers to see billing decreases.

Other options would allow 39.3% and 21.8% to see similar absolute billing decreases. This situation should not be confused with absolute rate decreases when comparing the block 1 rate to the existing flat rate.

With reference to the response to Question 1.1 in this IR set, it can be seen that by raising the block 1 rate above the current flat rate by lowering the Customer Charge, as in rate option 20, results in the same percentage of customers who will experience and overall decrease in annual bills.

2.3 Please provide a workable phasing-in proposal to introduce the RIB rate in two or three steps (in six-month intervals) to reduce the number of customers facing absolute rate decreases.

**Response:**

FortisBC understands the Commission to interpret “absolute rate decrease” to mean a situation in which the block 1 rate is lower than the flat rate (in conjunction with the Customer Charge) that collects the same revenue as the proposed RIB rate.

Eliminating all decreases in bills could be accomplished by keeping the Customer Charge and block 1 rate equal to or greater than the current level, and collecting all of the increases associated with revenue requirements and rebalancing in block 2.

2.4 To provide a better understanding of the different pricing principles considered, please expand the Table 8-3 by providing the results derived when:

a. The pricing principles A/C and B/D are applied to Options 11 and 17; and

b. The pricing principles E/G and F/H are applied to Options 2 and 8.

**Response:**

The additional scenarios have been added to the updated Table BCUC IR2 Q2.4 below.

## Table BCUC IR2 Q2.4

| | Base Rate Option | Threshold | Rate Increase Applied | | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Rate Increase* | | 8.90% | 6.50% | 3.40% | 6.50% |
| A | 2 | 1350 kWh | Both Blocks | Customer Charge | 28.93 | 29.65 | 30.34 | 30.34 | 30.34 |
| | | | | Block 1 Rate | 0.07526 | 0.08196 | 0.08729 | 0.09025 | 0.09612 |
| | | | | Block 2 Rate | 0.11138 | 0.12332 | 0.13271 | 0.13837 | 0.14957 |
| | | | | Ratio: Block 2 / Bl | 1.48 | 1.50 | 1.52 | 1.53 | 1.56 |
| B | 2 | 1350 kWh | Block 2 Only | Customer Charge | 28.93 | 29.65 | 30.34 | 30.34 | 30.34 |
| | | | | Block 1 Rate | 0.07526 | 0.07526 | 0.07526 | 0.07526 | 0.07526 |
| | | | | Block 2 Rate | 0.11138 | 0.13209 | 0.14845 | 0.15799 | 0.17687 |
| | | | | Ratio: Block 2 / Bl | 1.48 | 1.76 | 1.97 | 2.10 | 2.35 |
| 2.4b(i) | 2 | 1350 kWh | All Components | Customer Charge | 28.93 | 31.50 | 33.55 | 34.69 | 36.95 |
| | | | | Block 1 Rate | 0.07526 | 0.08196 | 0.08729 | 0.09025 | 0.09612 |
| | | | | Block 2 Rate | 0.11138 | 0.12129 | 0.12918 | 0.13357 | 0.14225 |
| | | | | Ratio: Block 2 / Bl | 1.48 | 1.48 | 1.48 | 1.48 | 1.48 |
| 2.4b(ii) | 2 | 1350 kWh | Customer Charge and Block 2 | Customer Charge | 28.93 | 31.50 | 33.55 | 34.69 | 36.95 |
| | | | | Block 1 Rate | 0.07526 | 0.07526 | 0.07526 | 0.07526 | 0.07526 |
| | | | | Block 2 Rate | 0.11138 | 0.13006 | 0.14492 | 0.15319 | 0.16955 |
| | | | | Ratio: Block 2 / Bl | 1.48 | 1.73 | 1.93 | 2.04 | 2.25 |
| C | Preferred Optic | 1600 kWh | Both Blocks | Customer Charge | 28.93 | 29.65 | 30.34 | 30.34 | 30.34 |
| | | | | Block 1 Rate | 0.07828 | 0.08525 | 0.09079 | 0.09387 | 0.09998 |
| | | | | Block 2 Rate | 0.11272 | 0.12515 | 0.13491 | 0.14085 | 0.15261 |
| | | | | Ratio: Block 2 / Bl | 1.44 | 1.47 | 1.49 | 1.50 | 1.53 |
| D | 8 | 1600 kWh | Block 2 Only | Customer Charge | 28.93 | 29.65 | 30.34 | 30.34 | 30.34 |
| | | | | Block 1 Rate | 0.07828 | 0.07828 | 0.07828 | 0.07828 | 0.07828 |
| | | | | Block 2 Rate | 0.11272 | 0.13720 | 0.15654 | 0.16782 | 0.19013 |
| | | | | Ratio: Block 2 / Bl | 1.44 | 1.75 | 2.00 | 2.14 | 2.43 |
| 2.4b(i) | 8 | 1600 kWh | All Components | Customer Charge | 28.93 | 31.50 | 33.55 | 34.69 | 36.95 |
| | | | | Block 1 Rate | 0.07828 | 0.08525 | 0.09079 | 0.09387 | 0.09998 |
| | | | | Block 2 Rate | 0.11272 | 0.12275 | 0.13073 | 0.13518 | 0.14396 |
| | | | | Ratio: Block 2 / Bl | 1.44 | 1.44 | 1.44 | 1.44 | 1.44 |
| 2.4b(ii) | 8 | 1600 kWh | Customer Charge and Block 2 | Customer Charge | 28.93 | 31.50 | 33.55 | 34.69 | 36.95 |
| | | | | Block 1 Rate | 0.07828 | 0.07828 | 0.07828 | 0.07828 | 0.07828 |
| | | | | Block 2 Rate | 0.11272 | 0.13480 | 0.15236 | 0.16214 | 0.18148 |
| | | | | Ratio: Block 2 / Bl | 1.44 | 1.72 | 1.95 | 2.07 | 2.32 |
| E | 11 | 1350 kWh | All Components | Customer Charge | 21.50 | 23.41 | 24.94 | 25.78 | 27.46 |
| | | | | Block 1 Rate | 0.08197 | 0.08927 | 0.09507 | 0.09830 | 0.10469 |
| | | | | Block 2 Rate | 0.11066 | 0.12051 | 0.12834 | 0.13271 | 0.14133 |
| | | | | Ratio: Block 2 / Bl | 1.35 | 1.35 | 1.35 | 1.35 | 1.35 |
| F | 11 | 1350 kWh | Customer Charge and Block 2 | Customer Charge | 21.50 | 23.41 | 24.94 | 25.78 | 27.46 |
| | | | | Block 1 Rate | 0.08197 | 0.08197 | 0.08197 | 0.08197 | 0.08197 |
| | | | | Block 2 Rate | 0.11066 | 0.13006 | 0.14549 | 0.15408 | 0.17107 |
| | | | | Ratio: Block 2 / Bl | 1.35 | 1.59 | 1.77 | 1.88 | 2.09 |
| 2.4a(i) | 11 | 1350 kWh | Both Blocks | Customer Charge | 21.50 | 22.04 | 22.54 | 22.54 | 22.54 |
| | | | | Block 1 Rate | 0.08197 | 0.08927 | 0.09507 | 0.09830 | 0.10469 |
| | | | | Block 2 Rate | 0.11066 | 0.12202 | 0.13097 | 0.13627 | 0.14677 |
| | | | | Ratio: Block 2 / Bl | 1.35 | 1.37 | 1.38 | 1.39 | 1.40 |
| 2.4a(ii) | 11 | 1350 kWh | Block 2 Only | Customer Charge | 21.50 | 22.04 | 22.54 | 22.54 | 22.54 |
| | | | | Block 1 Rate | 0.08197 | 0.08197 | 0.08197 | 0.08197 | 0.08197 |
| | | | | Block 2 Rate | 0.11066 | 0.13157 | 0.14812 | 0.15765 | 0.17651 |
| | | | | Ratio: Block 2 / Bl | 1.35 | 1.61 | 1.81 | 1.92 | 2.15 |
| G | 17 | 1600 kWh | All Components | Customer Charge | 21.50 | 23.41 | 24.94 | 25.78 | 27.46 |
| | | | | Block 1 Rate | 0.08449 | 0.09201 | 0.09799 | 0.10132 | 0.10791 |
| | | | | Block 2 Rate | 0.11152 | 0.12145 | 0.12934 | 0.13374 | 0.14243 |
| | | | | Ratio: Block 2 / Bl | 1.32 | 1.32 | 1.32 | 1.32 | 1.32 |
| H | 17 | 1600 kWh | Customer Charge and Block 2 | Customer Charge | 21.50 | 23.41 | 24.94 | 25.78 | 27.46 |
| | | | | Block 1 Rate | 0.08449 | 0.08449 | 0.08449 | 0.08449 | 0.08449 |
| | | | | Block 2 Rate | 0.11152 | 0.13445 | 0.15268 | 0.16284 | 0.18293 |
| | | | | Ratio: Block 2 / Bl | 1.32 | 1.59 | 1.81 | 1.93 | 2.17 |
| 2.4a(i) | 17 | 1600 kWh | Both Blocks | Customer Charge | 21.50 | 22.04 | 22.54 | 22.54 | 22.54 |
| | | | | Block 1 Rate | 0.08449 | 0.09201 | 0.09799 | 0.10132 | 0.10791 |
| | | | | Block 2 Rate | 0.11152 | 0.12323 | 0.13244 | 0.13795 | 0.14886 |
| | | | | Ratio: Block 2 / Bl | 1.32 | 1.34 | 1.35 | 1.36 | 1.38 |
| 2.4a(ii) | 17 | 1600 kWh | Block 2 Only | Customer Charge | 21.50 | 22.04 | 22.54 | 22.54 | 22.54 |
| | | | | Block 1 Rate | 0.08449 | 0.08449 | 0.08449 | 0.08449 | 0.08449 |
| | | | | Block 2 Rate | 0.11152 | 0.13623 | 0.15579 | 0.16706 | 0.18935 |
| | | | | Ratio: Block 2 / Bl | 1.32 | 1.61 | 1.84 | 1.98 | 2.24 |

* Does not include any forecast increases related BC Hydro flow-through

**3.0 Reference: Exhibit B-1, Section 5.2.3 Block Rate, p. 17**

**Mitigation of Customer Bill Impacts**

In the Application FortisBC used the total impact to customers/ bills as determining factor in setting the individual block rates and threshold.

3.1 Please discuss the anticipated actions that residential customers will undertake to respond to the new RIB rate structure's price signals. Specifically, provide examples of actions that will require limited or no customer investment as well as of actions that may be partially supported by DSM incentives.

**Response:**

Actions that require limited or no customer investment:

- Turning off lights that aren't required
- Reducing the amount of store lighting
- Repairing seals around doors and windows
- Reducing thermostat set point in the winter (if electrically heated)
- Increasing thermostat set point in the summer (if air conditioned)

All DSM incentives offered by FortisBC are expected to result in reduced customer energy consumption, and customers could undertake any of those in response to a RIB rate structure. Examples include:

- More efficient commercial lighting
- Improved insulation
- High-efficiency motors
- Building Optimization Program
- Energystar appliances and electronics

**4.0 Reference: Exhibit B-5, BCUC 1.18.2, p. 61**

**Interaction between RIB Rate and DSM Programs**

FortisBC states "However, any reduced residential load that results from a RIB rate may allow residential PowerSense expenditures to be reduced."

4.1 The Commission Panel is interested in gaining further insights as to the conservation impacts of various FortisBC programs.

4.1.1 Please provide additional analysis on the impact on both capacity and energy consumption in future years separately for RIB implementation, DSM programs, and how they interact.

**Response:**

FortisBC does not have any sources of data to determine how RIB rates and DSM programs will interact in the future, and is therefore unable to complete any additional analysis. The introduction of RIB rates will create uncertainty as they are new to FortisBC customers, and FortisBC will adjust its DSM programs as well as load forecasts as required and as it gains experience with RIB rates. The response to 5.2 provides a comparison of expected savings for RIB rates and the DSM program targets that were prepared independently. As that response shows, impacts of a RIB rate are potentially higher than single-year savings associated with the DSM targets. If FortisBC can achieve significant savings with a RIB rate, the rate impact associated with those savings combined with those from DSM programs will need to be evaluated to ensure customers are not unduly harmed.

4.1.2 What targets does FortisBC have for the RIB savings? Are these targets independent of targets for reductions from DSM?

**Response:**

FortisBC has applied for RIB rates in response to an Order from the Commission, not to target any specific level of energy savings. While FortisBC did consider the estimated savings with various RIB rates as one of many factors when evaluating which option best met the goals of the utility, specific savings are speculative until FortisBC gains experience with actual RIB rates. DSM targets remain independent of RIB savings at the present time. FortisBC does not intend to adjust or abandon its DSM targets until it sees the actual impacts associated with any approved RIB rate.

4.2 How does FortisBC plan to calculate the savings resulting specifically from the RIB and to separate them from the DSM savings?

**<u>Response:</u>**

The RIB Rate Application that FortisBC filed in March of 2011 did not include a proposal for reporting requirements or for the determination of conservation attributable solely to the impact of a RIB rate. Should the Commission order the implementation of a RIB rate and determine that reporting requirements include such an estimate, the Company will develop a methodology for determining the impact of RIB, however, as the RIB Decision is pending, FortisBC has not developed a plan to calculate the savings resulting specifically from RIB rates and to separate them from the DSM savings. This requires a sophisticated statistical analysis that needs to control for a number of variables that affect consumption, including temperature, DSM savings and Codes and Standards changes. While the Company agrees that it may be useful to have some estimate of these impacts, to fully develop the means of attaining the information is a relatively costly exercise both to establish and maintain. Doing so prior to having a mandate for the rate is premature.

4.3 Please describe under what specific circumstances, and when, FortisBC would reduce PowerSense expenditures.

**<u>Response:</u>**

Customer rates can rise if cost reductions due to conservation are less than the reduced revenues. Therefore, it is possible that DSM programs and conservation rates such as RIB may result in rate increases that FortisBC considers unacceptable to its customers. If this happens, FortisBC would consider reducing PowerSense expenditures.

4.4 What PowerSense expenditures would FortisBC reduce and why?

**Response:**

If PowerSense expenditures or programs needed to be reduced or eliminated after the analysis specified in BCUC IR2 Q4.3 is completed, FortisBC would focus on the least cost-effective DSM programs within the DSM portfolio.

4.5 Which PowerSense programs would FortisBC eliminate and why?

**Response:**

Please see the response to BCUC IR2 Q 4.4 above.

**5.0 Reference: Exhibit B-1, Section 2.3 Approval Requested, p. 5; and**
**Exhibit B-5, BCUC 1.4.3, p. 9; and**
**Exhibit B-5, BCUC 1.6.3, p. 15; and**
**Exhibit B-5, BCUC 1.6.4, p. 15.**
**RIB and TOU Rates**

In BCUC 1.4.3, FortisBC states: "FortisBC does not believe that the implementation of a RIB rate eases the introduction of time based rates. The Company further believes that the interim nature of the RIB rate, being effective between the current flat rate and the implementation of any time-based rates will create difficulties for the transition."

However, on page 5 of the Application, FortisBC states: "The RIB rate is intended to be the default, mandatory rate for all residential customers who are not taking service under FortisBC's Time-of-Use (TOU) option."

In BCUC 1.6.3, FortisBC states that it "believes that time based rates provide conservation benefits which are at a minimum as good as a RIB rate while simultaneously providing customers with more of an opportunity to conserve, thus reducing their total cost of electricity."

In BCUC 1.6.4, FortisBC states: "It remains the position of FortisBC that time-based conservation rates offer the best alternatives to flat rates for the Company and its customers. Should a RIB rate be mandated by the Commission, it is currently the Company's intention to introduce some suite of time-based rates to complement the RIB rates, likely on a voluntary participation basis."

5.1 Please clarify FortisBC's intentions with respect to the RIB and TOU rates. Specifically:

5.1.1 Regarding BCUC 1.6.3, please explain on what basis FortisBC believes that time based rates provide conservation benefits which are at a minimum as good as a RIB rate.

**Response:**

FortisBC believes that RIB rates and TOU rates can co-exist provided that one or the other is optional. Difficulties for customers could arise if one mandatory conservation rate (such as RIB) is implemented followed later by a different mandatory conservation rate (such as TOU). Different conservation rates can require different types of behaviours from customers, and therefore FortisBC believes consistency is important with respect to mandatory rates.

With respect to the response to BCUC 1.6.3, FortisBC was referring to the Ontario Energy Board Smart Price Pilot study cited in its 2009 Cost of Service and Rate Design Application, which showed energy savings from TOU rates were 6.0 per cent. This level of conservation is generally higher than the range of conservation estimates from RIB rates.

5.1.2 In response to BCUC 1.6.4, FortisBC seems to suggest that a TOU rate achieves the same or better conservation results than does a RIB rate. Does FortisBC agree with that statement? Please provide a justification for the response.

**Response:**

Please see the response to BCUC IR2 Q5.1.1.

5.1.3 Please explain how a voluntary TOU rate can achieve better conservation potential than a RIB rate? And why?

**Response:**

Although FortisBC cannot definitively say why TOU rates can achieve better conservation potential than RIB rates, it provides some possible reasons:

- TOU rate differentials tend to be larger than RIB rate differentials. This may result in a higher degree of customer awareness and response.
- Although TOU rates encourage customers to reduce consumption at specific times, in many cases that energy will not be replaced. For example:
    - A customer is not likely to go out of their way to turn on a light that was turned off during the peak period.
    - A customer that has turned down their air conditioning during a peak period is not likely to turn the air conditioner on for longer after the peak period expires.

5.1.4 Regarding BCUC 1.4.3, please further elaborate as to what FortisBC means by "the interim nature of the RIB rate". Is it FortisBC's position that if a voluntary TOU rate is implemented, customers would have a choice between taking service under a RIB rate or TOU rate?

**Response:**

FortisBC already has voluntary TOU rates available for most customer classes, and it believes customers should continue to have that choice. FortisBC has not promoted its current TOU rates to customers because the implementation of these rates on a wide-scale basis is problematic without an Advanced Metering Infrastructure.

5.2 What are the conservation targets, or predictions from the introduction of TOU rates? Please provide a comprehensive analysis showing the effects of TOU, RIB and DSM on both capacity and energy use for the residential class of customers for the years 2011 through 2015 inclusive.

**<u>Response:</u>**

While FortisBC has done some preliminary research on TOU rates, and currently has several voluntary TOU rates approved by the BCUC, it has not yet completed any detailed analysis on the effects of wide-scale time-based rates that could be implemented after an Advanced Metering Infrastructure was implemented.

The following table provides both the range of savings for the RIB rate under FortisBC's preferred option 8, estimates provided on TOU savings, and reported DSM target levels. While these numbers are the best data that FortisBC has at the current time, they are still very speculative.

| | Estimated Energy Savings | Estimated Peak Savings | Source |
|---|---|---|---|
| TOU | 75,675 MWh | 18 MW | BCUC IR1 Q6.2.1, percent savings applied to forecast residential energy and peak demand |
| RIB Option 8 | 23,591-69,274 MWh | 6-17 MW | BCUC IR1 Q19.2, peak savings based on % savings times estimated residential peak of 313 MW |
| DSM Targets | 16,400-21,000 MWh | 2011 – 1.4 MW<br>2012 – 2.9 MW<br>2013 – 4.1 MW<br>2012 – 5.5 MW<br>2014 – 7.0 MW | BCUC IR1 Q18.3 |

**6.0 Reference: Exhibit B-5, BCUC 1.9.1, p. 20**

**Exhibit B-5, BCUC 1.9.2, p. 20**

**Block 2 Rate and Long-Run Marginal Cost**

In BCUC 1.9.2, FortisBC states: "In the FortisBC RIB rate proposal, the higher price for power in the second block is intended to reflect the increasing cost of electricity as consumption increases, however it is not directly linked to an actual long-run marginal cost figure. The Company has not proposed a cap on the block 2 rate."

In BCUC 1.9.1, FortisBC also states: "Rather, and in a more generic sense, FortisBC acknowledges that the long-run marginal cost of power is higher than the average cost, and a higher Block 2 rate reflects this fact".

6.1 Please explain how the higher Block 2 rate 'reflects this fact' and why FortisBC feels it is not appropriate to directly link the Block 2 rate to the long-run marginal cost figure.

<u>**Response:**</u>

The "fact" that FortisBC referred to in the response was that the marginal cost of power is higher than the average cost of power. This fact is reflected in the fact that the block 2 rate is higher than the block one rate. In other words, setting a higher block 2 rate recognizes that customers should receive a price signal that reflects the higher cost of power as usage increases.

The Company does not contend that it is inappropriate to link the block 2 rate to its long term marginal cost, however, it is not part of the FortisBC proposal, and cannot be while the Customer Charge, threshold, and customer impact are set values. If FortisBC were to directly link its block 2 rate to the its long-run marginal cost of power, it would have to abandon one or more of its other criteria such as the customer impact criterion. FortisBC believes that although conservation is an important aspect of electricity pricing, it also must continue to consider customer impacts and thus customer affordability.

**7.0 Reference: Commission Order G-45-11, p. 3 and 9; and**
**Exhibit B-1, BCUC 1.9.3, pp. 21-22**
**Long-Run Marginal Cost of Electricity**

In the BC Hydro RIB Rate Re-Pricing Decision (Order G-45-11) the Commission reaffirmed the relevant key findings of the previous two BC Hydro rate design decisions; namely that conservation rates must play a pivotal role in future BC Hydro rate structures and that the long-run marginal cost (LRMC) of new supply is the appropriate referent for the Step-2 energy rate.

In BCUC 1.9.3, FortisBC states that the long-run marginal cost for power in 2011 is $73.80 per MWh and that its blended long-term avoided power purchase cost is $92.25 per MWh. In BCOAPO 1.16 (h), FortisBC shows the marginal cost to be $0.0304 per kWh and states that this is the marginal costs provided in response to BCUC 1.9.3.

7.1 Please provide the definitions of: marginal cost, long-run marginal cost for power, and blended long-term avoided power purchase costs.

**Response:**

Marginal Cost: For the purpose of this Application, FortisBC has used the term marginal cost of power to mean the cost of power that would be avoided based on existing resources if load reductions are realised. In the response to BCUC IR1 Q9.3, this marginal cost of power, or avoided cost of power was determined by "The change in power purchase expense divided by the change in gross load…". In the near term, this calculation reflects the fact that FortisBC is largely able to meet any energy gaps through increased take under the BC Hydro 3808 contract. It is therefore an avoided cost calculation that applies to the forecast of avoided power purchase expense over the 2012 to 2015 time frame. (Note: as shown in the response to BCUC IR1 Q9.3, that this avoided cost is estimated to be $0.03804 per kWh in 2012 and not the $0.0304 referenced in the pre-amble to this question).

Long-run Marginal Cost: For the purpose of this Application, FortisBC uses the term "long-run marginal cost of power" to define the cost to acquire additional power where the existing resources are insufficient to meet load requirements. In the near to medium term, FortisBC expects to meet incremental requirements through increased market purchases. For the purposes of this application, therefore, the determination of long run marginal cost is based on a forecast of the market price of power and does not represent the cost of new construction. In the response to BCUC IR1 Q9.3 the long-term avoided cost of $73.80 per MWh is a levelized cost calculation from 2011 to 2040 based on the 2011 FortisBC Energy & Capacity Market Assessment. This report has been filed with the Commission as part of the Company's 2012 – 2013 Revenue Requirements Application and 2012 Integrated System Plan, in its 2012 Long Term Resource Plan and the relevant table is found on Tab B, page 23, Table 5.1.3.3-A. The report provides updates to the marginal cost figures as these were based on a preliminary version. A comparison of the original numbers to those recently filed is found in the table below.

| | Original ($/MWh) | Updated |
| --- | --- | --- |
| 2011 Market Assessment | 73.80 | 84.94 |
| BC Hydro 2007 CPR | 154.15 | 154.15 |
| Blended value for DSM | 92.25 | 104.32 |
| Marginal RIB Cost per BCUC IR 1.9.3 | 38.04 | 38.04 |

7.2 Please confirm what FortisBC's long-run marginal cost of power is expected to be for the years 2011 through 2015 inclusive.

**Response:**

Please see the discussion in BCUC IR2 Q7.1 for a discussion on long run marginal cost versus marginal or avoided cost. For the purposes of this Application, FortisBC's long run marginal cost is based on the cost to acquire additional market based power when the existing resources are insufficient to meet load requirements and is estimated to be $73.80 at the time of the Application, and has since been updated to $84.94 per kWh.

However, as discussed in the response to BCUC IR1 Q9.3, over the period 2011 to 2015 FortisBC expects to largely meet its incremental requirements through increased energy purchases under the BC Hydro 3808 contract. Therefore the marginal cost during this period is largely based on avoided purchases under the BC Hydro 3808 contract and is estimated to be $0.03804 per kWh in 2012 as per Table BCUC IR1 Q9.3.

7.3 Does the term 'CDPR' equate the term 'CPR' in Table 3.2.2 (BCUC 1.9.3)? Please confirm that CPR means 'Conservation Potential Review'.

**Response:**

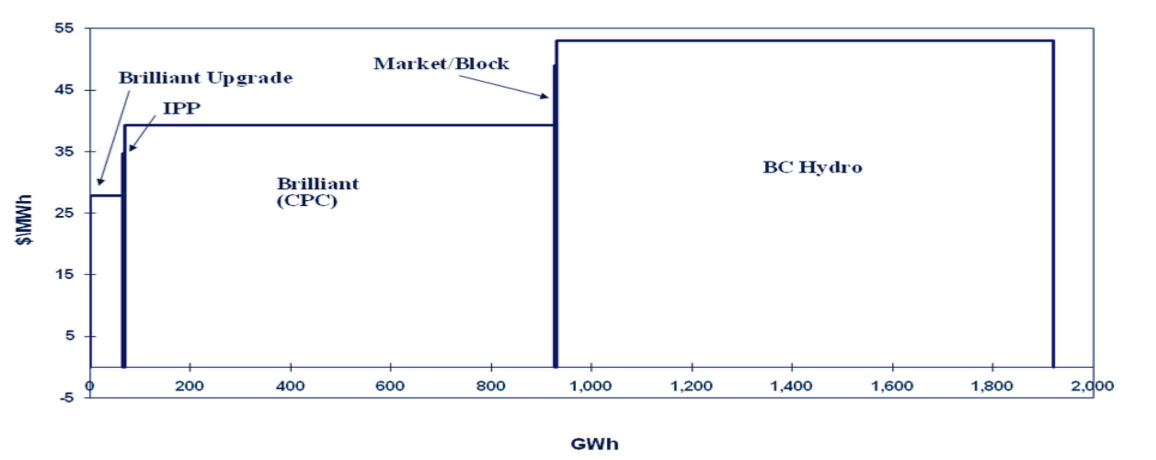
CDPR refers to a "Conservation and Demand Potential Review", which is similar to a CPR but specifically includes an evaluation of the potential of demand-reduction measures. FortisBC confirms that CPR means "Conservation Potential Review".

7.4 Please provide the details of the amount and cost to FortisBC of its own supply of electricity, any electricity purchase contracts it has, and purchases it makes on the open market.

The amount and cost of the Company's expected 2012 electricity purchase contracts and purchases on the open market are summarized below in Figure BCUC IR2 Q7.4 and are covered in greater detail in the current FortisBC 2012/2013 Revenue Requirement Application at page 1 of Section 4.1. The significant contracts are summarized below. The relevant sections of the Revenue Requirement Application, Section 4.1 are attached to these IR responses as Attachment 7.4

1. Brilliant Upgrades: The Company's lowest cost contractual power is from the Brilliant upgrades with a 2012 forecast rate of $27.87 per MWh and a volume of 65 GWh;
2. IPP Power: The estimated 2012 IPP rate is $34.64 per MWh and volume of 4 GWh;
3. Brilliant Plant: The estimated 2012 Brilliant Plant rate is estimated to be $39.14 per MWh and a volume of 859 GWh;
4. Open Market Power: The estimated 2012 market cost of power is $48.76 per MWh and a volume of 4 GWh;
5. BC Hydro Power Purchase Agreement: The estimated 2012 cost of BCH PPA power is $38.19 per MWh and $6,549 per MW Month. The combined rate for 2012 is estimated to be $53 per MWh.
6. The cost to the Company of its own supply of electricity on a forecast 2012 gross entitlement of 1611 GWh is estimated to be $25 per MWh.

**Figure BCUC IR2 Q7.4**



# 4.0 INTRODUCTION

FortisBC's cost of service is forecast to increase by approximately $15.7 million in 2012 and a further $24.6 million in 2013. The increased cost of service is necessary for the Company to continue to provide safe and reliable service to its customers. The increasing customer counts and electrical facilities outlined in Appendix G of the Application continue to put pressure on FortisBC's cost of providing services to its customers.

While the increased cost of service is attributable to a number of factors, there are three key underlying drivers: (1) increases in power purchase costs; (2) increases in utility rate base; (3) increases in the costs associated with financing that rate base including depreciation.

Each of these items is further discussed below.

## 4.1 POWER PURCHASE AND WHEELING

This section includes an estimate of 2011 Power Purchase Expense based on FortisBC's actual results to April 30, 2011, with an estimate for May through December, and a complete forecast of Power Purchase Expense for 2012 and 2013 (see Tables 4.1.4-2 and 4.1.4-3).

As shown in Table 4.1-1 below, Power Purchase Expense is forecast at $91.0 million for 2012 and $98.8 million for 2013, as compared to $76.0 million currently estimated for 2011. The increases in 2012 and 2013 are primarily due to an increase in forecast load, greater use of the BC Hydro Power Purchase Agreement (PPA), annual increases to the Brilliant and BC Hydro rates, and the inclusion of the management costs associated with power purchase costs (explained in section 4.1.2.6). Balancing Pool adjustments account for the difference between energy entitlements under the Canal Plant Agreement (CPA) and actual usage.

**Table 4.1-1 Total Power Purchase Expense (2010-2013)**

| | | Actual 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| | | ($000s) | | | |
| 1 | Brilliant | 33,216 | 32,267 | 35,601 | 36,785 |
| 2 | BC Hydro | 29,544 | 36,874 | 52,519 | 57,965 |
| 3 | Independent Power Producers | 914 | 153 | 155 | 158 |
| 4 | Capacity Block Purchases | 2,080 | 2,291 | 2,475 | 2,808 |
| 5 | Market Purchases | 8,222 | 4,211 | 214 | 545 |
| 6 | Surplus Revenues | (1,000) | (259) | (284) | (267) |
| 7 | Capital Projects | (398) | (467) | - | - |
| 8 | Special and Accounting Adjustments | 421 | 385 | (750) | (750) |
| 9 | Balancing Pool | (1,036) | 501 | (156) | - |
| 10 | Planning Reserve Margin | - | - | - | 311 |
| 11 | Management Expense | - | - | 1,211 | 1,266 |
| 12 | TOTAL | 71,964 | 75,956 | 90,984 | 98,821 |

### 4.1.1 Review of 2011

The winter of 2010-11 saw above-average snow packs and stronger than normal run-off in the first quarter. This early run-off combined with ongoing moderate natural gas prices and a growing base of variable and unpredictable wind generation in the Pacific Northwest provided significant opportunities to obtain market energy at rates below those of the BC Hydro PPA.

FortisBC annual gross load is forecast to be 29 GWh above approved 2011 (net of Demand Side Management (DSM) savings). Power purchase expense is expected to be $5.3 million below approved 2011 for the year, as shown in Table 4.1.1-1 below as a net result of:

a) Lower BC Hydro costs, net of accounting adjustments, of $9.9 million, due primarily to a reduced BC Hydro purchase volume as a result of increased market purchases at rates below the 3808 rate;

b) A combined increase of $3.8 million in market purchases and balancing pool usage; and

c) A $0.75 million reduction to Power Purchase Expense negotiated in the 2011 NSA.

The Company has included the interim BC Hydro rate increase of 8 percent on May 1, 2011, including the deferral account rate rider, as well as estimated BC Hydro rate increases of 8 percent on each of April 1, 2012 and April 1, 2013.

In 2011, there was normal annual generator maintenance on the FortisBC generating units. The Corra Linn Unit 1 Upgrade and Life Extension (ULE) project was completed in March 2011, which required a planned outage beginning in 2010. The ULE for Corra Linn Unit 2 is expected to begin in the summer of 2011 and should be completed by December 2011. The increased power purchase costs as a result of these projects are offset by charges to the capital cost of the project and therefore do not impact Power Purchase Expense (see Line 7 of Table 4.1.1-1). The Company forecasts receiving the increased entitlements under the CPA for these projects in 2011 and 2012 as detailed below.

**Table 4.1.1-1 Total Power Purchase Expense (2011)**

| | | Approved 2011 | Forecast 2011 | Difference |
|---|---|---|---|---|
| | | ($000s) | | |
| 1 | Brilliant | 32,282 | 32,267 | (16) |
| 2 | BC Hydro | 46,811 | 36,874 | (9,937) |
| 3 | Independent Power Producers | 168 | 153 | (16) |
| 4 | Capacity Block Purchases | 2,406 | 2,291 | (115) |
| 5 | Market Purchases | 856 | 4,211 | 3,356 |
| 6 | Surplus Revenues | (670) | (259) | 411 |
| 7 | Capital Projects | (377) | (467) | (89) |
| 8 | Special and Accounting Adjustments | - | 385 | 385 |
| 9 | Balancing Pool | 486 | 501 | 15 |
| 10 | BCUC Negotiated Rate Reduction | (750) | | 750 |
| 11 | **TOTAL** | 81,212 | 75,956 | (5,256) |

### 4.1.2 Power Purchase

The goal of the Company's resource acquisition policy is to meet customer load requirements for the lowest reasonable cost with minimal environmental impacts. This goal is subject to ongoing resource uncertainties that are described in greater detail in the following section.

#### 4.1.2.1 POWER PURCHASE/RESOURCE UNCERTAINTY

The Company has long-term, firm resources from which it can supply over 98 percent of its annual energy requirements. The small shortfall is due to system capacity constraints during peak load days. An advance purchase of winter capacity blocks from Powerex has been obtained to meet the majority of the peak winter loads.

Concurrently with the 2012-13 RRA ,the Company filed its 2012 Integrated System Plan, one component of which is the 2012 Resource Plan . The 2012 Resource Plan reviews appropriate long term resource options to meet the Company's remaining energy requirements. Potential changes resulting from the 2012 Resource Plan will not impact resource acquisition during 2012 and 2013.

#### 4.1.2.2 POWER PURCHASE COSTS

Power Purchase costs for 2012 and 2013 are shown in Tables 4.1.4-2 and 4.1.4-3. Where applicable, power purchase costs have been forecast using contract prices plus a forecast of future market prices.

The Company proposes to establish a deferral account to collect the difference between actual and approved 2012 and 2013 Power Purchase Expense as explained in Section 4.1.4.

***Existing Resource Base and Long Term Purchases***

FortisBC uses a combination of Company-owned generation entitlements and contracted firm supply to meet its load requirement. Any capacity or energy deficits that remain after using all other firm resources are met with short-term or spot market purchases. The Company's resources consist of:

A. FortisBC owned generation entitlements; with an estimated winter peak capacity of 227 MW in 2012 and 2013 (actual capacity will depend on the final CPA entitlement increases as a result of the ULE projects). There are no costs associated with FortisBC owned generation included in the power purchase estimates, except for the Balancing Pool adjustments, which account for the difference between energy entitlements and actual usage.

B. The Brilliant Power Purchase Agreement (BPPA) (a 129 MW contract terminating in 2056), and an amendment to the BPPA which reflects the purchase of the Brilliant Upgrade power (20 MW) and the Brilliant Tailrace Capacity agreement (5 MW);

C. The Company's Power Purchase Agreement with BC Hydro (200 MW) priced at BC Hydro's Rate Schedule 3808 (the BC Hydro PPA), which terminates September 30, 2013;

D. A number of small Independent Power Producer (IPP) contracts, and;

E. A number of market purchase arrangements described below.

**A. FortisBC Owned Generation Entitlements**

Company owned generation energy entitlements under the CPA are forecast as follows:

**Table 4.1.2.2-1 CPA Energy Entitlement**

| | | Actual 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| 1 | Entitlement Energy (GWh) | 1,591 | 1,601 | 1,611 | 1,611 |
| 2 | Change (%) | | | 0.6% | 0.0% |
| 3 | Outages/Spill (GWh) | -23 | -14 | -6 | -6 |
| 4 | Net Entitlement Energy (GWh) | 1,568 | 1,587 | 1,604 | 1,604 |
| 5 | Storage (GWh) | -37 | 17 | -4 | 0 |
| 6 | Usable Entitlement Energy (GWh) | 1530 | 1604 | 1600 | 1604 |

The expected increased CPA entitlements are the result of the ULE program, which is scheduled to be complete by the end of 2011. The outage forecast for 2012 and 2013 is based on average actual loss of entitlement energy due to maintenance and forced outages between 2008 and 2010. In 2011 the Company forecasts that it will use 17 GWh of storage energy from the CPA Exchange accounts (balancing pool), and in 2012 it will store 4 GWh of energy. In 2013 the use of the storage account is balanced at 0 GWh for the year. The use of the storage account is the only portion of the CPA entitlement that is included in the Power Purchase expense forecast. When the Company stores energy, a credit is applied to Power Purchases, and when the Company uses energy, a charge is applied to Power Purchases. The Company uses the BC Hydro PPA rate prevalent at the end of the year to value this storage or usage.

Company owned generation capacity entitlements under the CPA are forecast as follows for December, the peak forecast month:

**Table 4.1.2.2-2 CPA Winter Peak Capacity Entitlement**

| | | Actual 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| 1 | Capacity at winter peak ( MW) | 223 | 225 | 227 | 227 |
| 2 | Change (%) | | | 0.9% | 0.0% |
| 3 | Outages/Reserves (MW) | -26 | -26 | -10 | -10 |
| 4 | Forecast Usable Entitlement (MW) | 197 | 199 | 216 | 216 |

FortisBC is required to hold reserves of 4.45 percent on CPA capacity entitlements. In 2011, the Company forecasts an outage of 16 MW over the winter peak to account for the ULE project at Corra Linn Unit 2. For 2012 and 2013 there are no forecast maintenance outages over the winter peak.

## B. Brilliant Power Purchase Agreement and Tailrace Agreement

The Company purchases power under the BPPA and under the Brilliant Power Purchase Second Amendment Agreement, both of which have been approved by the Commission.

The prices paid under the BPPA are based on forecasts of the annual operating and maintenance costs and capital charges for the plant.

The price for the Brilliant Power Purchase Second Amendment Agreement is as follows: for the unregulated-flow component of the upgrade power, price is based on a forecast of the all-in capital cost of the upgrades. The regulated-flow component was recalled by the owner in late 2005 and no regulated upgrade energy is expected to be available for purchase in 2012 or 2013.

A forecast of the prices and usage of energy from the Brilliant Plant under long-term contract is as follows:

**Table 4.1.2.2-3 Brilliant Energy Purchases**

| | | Actual 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| 1 | Base Volume (GWh) | 859 | 859 | 859 | 859 |
| 2 | Base ($/MWh) | 36.45 | 35.31 | 39.14 | 40.46 |
| 3 | Change (%) | | -3.1% | 10.8% | 3.4% |
| 4 | Upgrade Volume (GWh) | 65 | 65 | 65 | 65 |
| 5 | Upgrade - Unregulated ($/MWh) | 26.55 | 27.19 | 27.87 | 28.56 |
| 6 | Change (%) | | 2.4% | 2.5% | 2.5% |
| 7 | Outages (GWh) | -2.8 | -2.5 | -3.5 | -3.5 |
| 8 | Total Usable Brilliant Dam (GWh) | 922 | 922 | 921 | 921 |

As in the past, the base rate for 2011 and 2012 includes a "true-up" adjustment for prior years, which is the difference between the forecast and actual costs as allowed under the Agreements. For 2011 the adjustment amounts to a decrease in costs of $2.1 million, based on the difference between forecast and actual costs for 2008 and 2009. For 2012, the adjustment amounts to a decrease of approximately $0.1 million, based on the actual costs for 2010. The Company proposes that the true-up of the BPPA costs be included in the Power Purchase Variance Deferral Account described in section 4.1.4. The Power Purchase Variance Deferral Account is not approved, the true-up of BPPA costs would remain a component of Power Purchase Expense.

The Company bases the Brilliant maintenance outages on the average loss of energy due to forced and maintenance outages between 2008 and 2010, and has included an energy reduction for the planned maintenance outage in March of each year.

In addition to the energy, the Company also receives the associated capacity from the Brilliant plant. The cost for the capacity is included in the energy rates shown above in Table 4.1.2.2-3. Furthermore, the Company has long-term rights to approximately 5 MW of capacity under the Brilliant Tailrace Agreement, also approved by the Commission. A forecast of the price and usage of capacity from the Brilliant Plant under the long-term contracts is as follows:

**Table 4.1.2.2-4 Brilliant Winter Peak Capacity Purchases**

| | | Actual 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| 1 | Base Capacity | 129 | 129 | 129 | 129 |
| 2 | Upgrade Capacity | 20 | 20 | 20 | 20 |
| 3 | Tailrace Capacity | 5 | 5 | 5 | 5 |
| 4 | Tailrace ($/MW/Month) | 3,897 | 3,968 | 4,041 | 4,115 |
| 5 | Change (%) | | 1.8% | 1.8% | 1.8% |
| 6 | Outages/Reserves (MW) | -7 | -7 | -7 | -7 |
| 7 | Forecast Usable Capacity (MW) | 147 | 147 | 147 | 147 |

The Company is required to hold reserves of 4.45 percent on the Base and Upgrade Brilliant Capacity, consistent with the reserves held on FortisBC entitlement resources. Columbia Power Corporation (CPC) holds the reserve on the Tailrace capacity. For 2011, 2012 and 2013 there are no forecast maintenance outages over the winter peak from Brilliant.

### C. BC Hydro

The BC Hydro PPA will expire in September of 2013. For this Application the contract has been assumed to be renewed on similar terms. The rates and usage of the BC Hydro PPA are shown in Table 4.1.2.2-5 below:

**Table 4.1.2.2-5 BC Hydro 3808 Purchases**

| | | Actual 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| 1 | Energy (GWh) | 600 | 708 | 991 | 1020 |
| 2 | Average $/MWh | 32.36 | 35.28 | 38.19 | 41.23 |
| 3 | Change (%) | | 9.0% | 8.2% | 8.0% |
| 4 | Capacity (MW) | 200 | 200 | 200 | 200 |
| 5 | $/MW/Month | 5,478 | 5,976 | 6,549 | 7,073 |
| 6 | Change (%) | | 9.1% | 9.6% | 8.0% |

The Company has used BC Hydro's current interim rates as at May 1, 2011, including the deferral account rate rider. Forecast BC Hydro rate increases of 8 percent commencing April 1, 2012 and April 1, 2013 are also included. The Company proposes that any variances in BC Hydro rates between forecast and actual be included in the Power Purchase Variance Deferral Account described in section 4.1.4. If the Power Purchase Variance Deferral Account is not approved, the Company expects to flow through changes in BC Hydro rates at the time they are approved, as it currently does.

### D. Independent Power Producers

The Company has eight small power purchase contracts with IPPs from which FortisBC is supplied energy, but no capacity. Table 4.1.2.2-6 shows the forecast rates and usage from IPPs.

**Table 4.1.2.2-6 IPP Purchases**

| | Energy | Actual 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| 1 | Volume (GWh) | 37 | 5 | 4 | 4 |
| 2 | Change (%) | | -87.4% | -4.6% | 0.0% |
| 3 | $/MWh | 24.84 | 32.68 | 34.64 | 35.33 |
| 4 | Change (%) | | 31.6% | 6.0% | 2.0% |

The IPP rates are based on actual rates paid to the IPPs between 2008 and 2010, escalated by the forecast change in the BC Consumer Price Index (CPI). The weighted average IPP rate is slightly lower than the BC Hydro PPA rate.

## E. Market Purchases

Based on current resources and long-term agreements, the Company is resourced for almost all of its energy needs, but only 78 percent of the winter peak capacity. In order to meet the Company's peak demands, market purchases of power are required.

For 2012 and 2013 the Company uses (i) Market Purchases Made in Advance and (ii) Spot Market Purchases, described below.

(i) Market Purchases Made in Advance

For the last few years, cost-effective capacity block purchases from Teck Metals Ltd. (Teck) have been available. With the sale of one third of Teck's Waneta plant to BC Hydro in 2010, capacity purchases for the winter months are no longer available from Teck. As a result of this transaction, FortisBC entered into a five year deal with Powerex to provide winter capacity blocks to replace what was previously available from Teck. Table 4.1.2.2-7 below is a summary of capacity purchases from Powerex in 2012 and 2013.

**Table 4.1.2.2-7 Powerex Capacity Block Purchases**

| | Month | Amount (MW) | Total Cost ($US) | $US/MW |
|---|---|---|---|---|
| 1 | January 2012 | 150 | 899,550 | 5,997 |
| 2 | February | 75 | 449,775 | 5,997 |
| 3 | November | 50 | 337,350 | 6,747 |
| 4 | December | 125 | 843,375 | 6,747 |
| 5 | January 2013 | 150 | 1,012,050 | 6,747 |
| 6 | February | 75 | 506,025 | 6,747 |
| 7 | November | 50 | 352,700 | 7,054 |
| 8 | December | 125 | 881,750 | 7,054 |

. While these capacity blocks help to meet the winter peak, the Company still has a capacity deficit of 32 MW in 2012 and 43 MW in 2013. The Company anticipates meeting these peaks with spot market purchases or purchases made in advance of the expected need.

(ii) Spot Market Purchases

Any remaining peak requirements will be purchased on a day-ahead or real-time basis with the forecast rates as follows:

**Table 4.1.2.2-8 Spot Market Purchases for Capacity**

| | | Actual 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| 1 | Peak Month Capacity Deficit (MW) | 206 | 41 | 32 | 43 |
| 2 | Volume (GWh) | 78 | 70 | 4 | 4 |
| 3 | $/MWh | 39.73 | 35.29 | 48.76 | 58.60 |
| 4 | Change (%) | | -11.2% | 38.2% | 20.2% |

The FortisBC capacity deficit in 2010 was a result of the peak demand occurring in late November, and the Company not having sufficient capacity blocks in place to meet the unexpectedly heavy November load. Had the peak demand occurred in January or December the amount of short-term market purchases required to meet peak demand would have been significantly less, since the winter peak is anticipated to occur in those months and more capacity block resources are available. The amount of energy required to meet peak capacity demand is calculated based on the Company's expected load duration curves. These load curves are forecast based on the average monthly load curves calculated from actual load data for the FortisBC system from 2007 to 2010, which is then escalated by the difference between the peak average hourly load, and the peak load forecast. For 2012, the Company is forecasting a 32 MW deficit on its winter peak demand. Based on the Company's forecast load curves, it will have a deficit for the 9 peak hours of the month, and will require purchases of 115 MWh to cover this deficit. However, in real-time it is impossible to purchase exactly what is needed due to uncertainty in the hourly load forecast and other system conditions. For each hour that the Company is expected to be in the market to meet capacity, it is anticipated that the real-time operator will, on average, purchase at least 10 MW more than what is required to account for variations in the load forecast within the hour. As a result an additional 10 MW of purchases for every hour that the Company is anticipated to be in the market has been included. For December 2012, this accounts for an additional 90 MWh of purchases. In both 2012 and 2013, the Company is forecasting a capacity deficit for 7 months of the year, ranging from 1 hour of the month to 61 hours.

The forecast market prices are based on a variety of sources, including an April 29, 2011 Argus Media Publication titled "Argus US Electricity", and consultations with both Shell Energy North America and Powerex. These sources are used to derive a monthly Mid-Columbia (Mid-C) price forecast, and using the methodology described in Section 4.1.2.3 to extrapolate an hourly price forecast. The hourly forecast is used to estimate the cost of meeting the Company's peak demand shortfall, and the cost to meet the Company's energy deficit. The lower rate in 2011 as compared to 2012-2013 is related to attractive prices during the first quarter of 2011 as well as buying market energy to meet load in additional hours beyond the very peak hours to displace BC Hydro capacity.

Spot market purchases to meet peak capacity requirements are expected to be approximately $0.2 million in 2012 and 2013 compared to $2.5 million in 2011. The quantity of spot market purchases for capacity in 2011 is above what is forecast for 2012 and 2013 because market prices were low enough in the first four months of 2011 to make these opportunities possible. Additionally, the Company was buying market energy to meet load in additional hours beyond the very peak hours to displace BC Hydro capacity. Unforeseen market conditions in the first four months of 2011 made these opportunities possible.

In addition to purchasing for capacity, the Company also makes market purchases for energy to fill any deficit in firm energy supply, to displace BC Hydro energy at a lower cost, to fill the CPA Exchange accounts and to meet increased load. Table 4.1.2.2-9 below shows the forecast volume and rate of market purchases for energy.

**Table 4.1.2.2-9 Spot Market Purchases for Energy**

| | | Actual 2010 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| 1 | Volume (GWh) | 212 | 205 | 0 | 5 |
| 2 | $/MWh | 24.06 | 8.44 | 53.04 | 60.08 |
| 3 | Change (%) | | -64.9% | 528.8% | 13.3% |

It is anticipated that less than 1 GWh in 2012 and approximately 5 GWh in 2013 of non-BC Hydro PPA power (market energy) will be required in order to maintain appropriate energy reserves. While the amount of the energy deficit is small in 2012 and 2013, the Company's energy deficit will continue to grow.

The Company's estimate of 2011 Power Purchase Expense includes actual market purchases to April 30, 2011, and a forecast of market purchases for the remainder of the year based on current market forecasts. Because of this, the quantity of market purchases for energy is substantially larger in 2011 than in 2012 and 2013. While the Company does not forecast any of these opportunities in 2012 and 2013, a reduction of $0.75 million to Power Purchase Expense is included in each year, to account for potential savings due to similar opportunities.

The total cost of purchases from the market (market purchases made in advance and spot market purchases) is expected to be approximately $2.7 million in 2012 and $3.4 million in 2013, compared to approximately $6.5 million in 2011.

#### 4.1.2.3 MARKET PRICE FORECAST METHODOLOGY

FortisBC's market forecast for Mid-C energy is based on a variety of sources, including an April 29, 2011 Argus Media Publication titled "Argus US Electricity", and consultations with both Shell Energy North America and Powerex. Based on these sources, the Company's acquires two monthly forecasts, one for heavy load hours (HLH) and one for light load hours (LLH). This provides the monthly block price of both heavy load and light load energy for a twelve month period. In order to get the energy from the MID-C to the FortisBC service territory, the Company applies a cost of $4 USD/MWh to the forecast Mid-C price as a transmission charge. The Company escalates this forecast based on annual forecasts from the sources above, in order to extrapolate a 5 year market price forecast.

For market purchases required only for energy (line 37 in Tables 4.1.4-2 and 4.1.4-3), the Company assumes that the block rate is the rate that it will be required to be paid. For market purchases required to meet peak demand (line 38 in Tables 4.1.4-2 and 4.1.4-3), it is assumed that the Company will only be in the market for the peak hours of the month. FortisBC's peak hours for any month are usually the same peak hours as the rest of the Northwest Power Pool, which usually causes increased prices during these peak hours and peak days. Because of this, the Company anticipates that the block price for all heavy load hours will not accurately reflect the cost that the Company expects to pay to for capacity to meet its peak demand. The Company adds a conservative 20 percent premium to the block forecast of heavy load energy to account for the peak hour premium. Additionally, these forecasts are converted to Canadian dollars, based on the Company's forecast exchange rates (line 46 of Tables 4.1.4-2 and 4.1.4-3).

#### 4.1.2.4 MARKET ACTIVITY

In addition to using the market for capacity and energy deficits, the Company will continue its strategy of attempting to supply its energy and capacity needs at the lowest cost throughout the year using the real-time market, as well as purchases made in advance. The possibilities for savings depend on market prices and system requirements, and the Company is not always able to forecast these savings in advance. For example, in the first four months of 2011, the

Company has been able to take advantage of market prices which were well below the forecast market prices at the time of the 2011 Revenue Requirements Application. While the current market price forecasts are not looking as favourable as what has been experienced so far in 2011, the Company has included a $0.75 million reduction to Power Purchase Expense in each of 2012 and 2013 to account for potential market savings as discussed above.

#### 4.1.2.5 PLANNING RESERVE MARGIN

The Company is implementing a planning reserve margin (PRM) in 2012. The amount of PRM required is shown in line 30 of Tables 4.1.4-2 and 4.1.4-3, and is calculated based on the "FortisBC Inc. Planning Reserve Margin Report" provided as Appendix E to the 2012 Resource Plan. For the duration of the current PPA with BC Hydro, FortisBC will meet this planning reserve requirement through its PPA with BC Hydro. The agreement states that BC Hydro will use "reasonable efforts" to supply FortisBC's load beyond the 200 MW contract amount, and the Company believes that while this contractual arrangement is a non-firm resource, it is a reliable source of PRM. There is no cost to hold this PRM under the PPA and since it is not expected to be used, no cost has been included as part of Power Purchase Expense.

The BC Hydro PPA expires September 2013, at which point the Company believes that it is prudent to secure a PRM resource from another source. While the source of the PRM is unclear at this time, PRM costs have been included from October 1, 2013 onwards, based on estimates provided by Midgard Consulting. The PRM cost in 2013 is forecast to be $0.311 million.

#### 4.1.2.6 POWER PURCHASE MANAGEMENT EXPENSES

The Company has included a portion of the management expense required to manage power purchase costs in 2012 and 2013 in the estimate of the total Power Purchase Expense and excluded it from the Operating and Maintenance (O&M) budget. The Power Purchase Management Expense (PPME) amount equals $1.2 million in 2012 and $1.3 million in 2013. This change to how this expense is treated is being made to help ensure that the resources required to plan, implement and mitigate Power Purchase Expense are sufficient. This is achieved by linking this expense directly to the overall Power Purchase Expense rather than as a component of the O&M budget.

Power Supply is the group responsible for planning and securing power on a short (hourly and daily), medium (monthly and seasonally), and long-term basis. The sources of power are Company owned generating units, power supply contracts, and market transactions that range

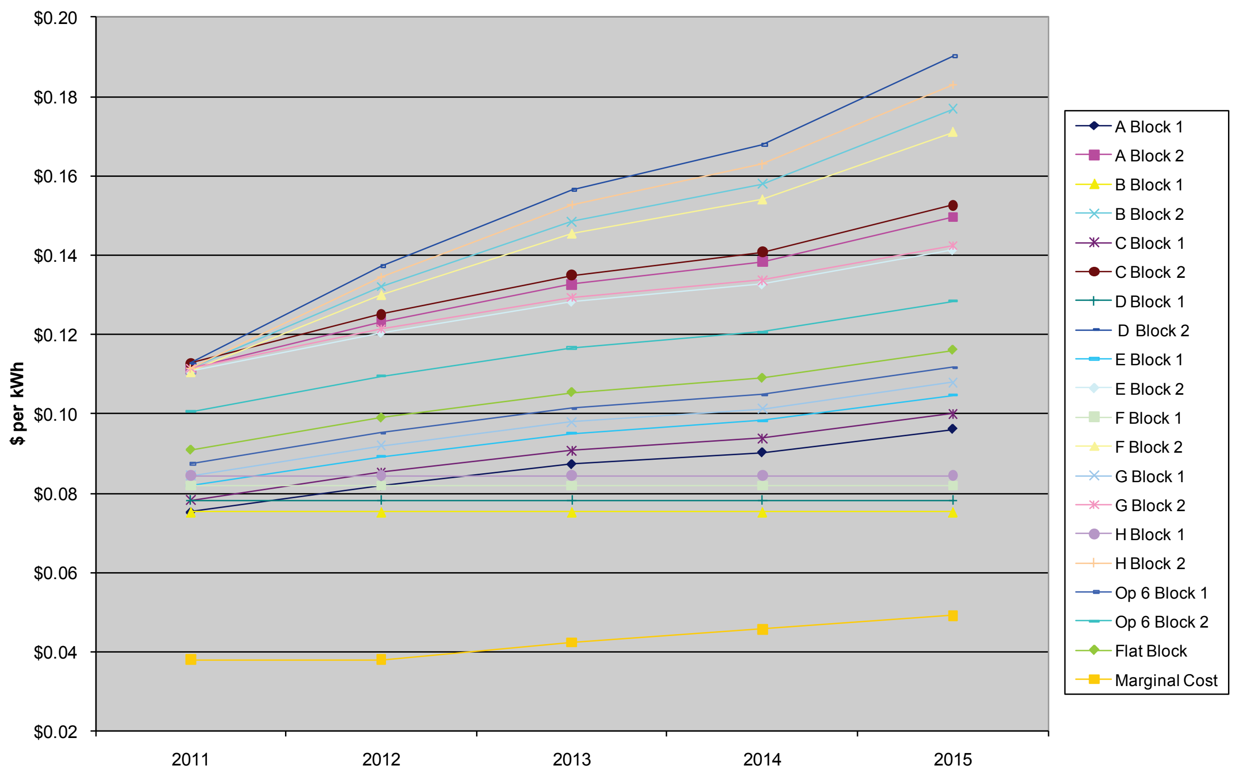
**8.0 Reference: Exhibit B-1-2, Errata No. 3, Updated BCUC 1.22.1, Updated page 75**

8.1 The updated BCUC 1.22.1 contains a graph that purports to show the marginal cost of power, but the line representing that value appears to be missing. Please supply an updated graph with that line clearly visible.

**Response:**

Please refer to Table BCUC IR2 Q8.1.

**Table BCUC IR2 Q8.1**
**Comparison of Block 1 and 2 Rates to Flat Block and Marginal Cost**



**9.0 Reference: Exhibit B-1, Section 7.2 Elasticity Assumptions, p. 21; and Table 7-2 Residential Inclining Block Rate Options Comparison, p. 22**

In Section 7.2 of the Application FortisBC states that “The Company is of the opinion that arriving at a precise level of conservation owing to the RIB rate will not be determinative in the decision to implement such a rate ….”. Also, in Table 7-2 of the Application FortisBC shows potential conservation impacts for three different ranges of elasticity scenarios.

9.1 The Commission Panel is interested in gaining further insights to billing impacts over the period 2011 to 2015 and conservation results by looking at the different assumptions related to elasticity. Please elaborate on how much and why FortisBC believes energy consumption changes, particularly for load billed in Block 2, for Options 1 to 18.

**Response:**

In the load forecast submitted as part of its 2012 – 2013 Revenue Requirements and 2012 Integrated System Plan, FortisBC has phased in a 1.9 percent reduction in residential load over the period 2012-2017. The overall impact on energy consumption is shown in Table 7.2 of the Application (Exhibit B-1) for each of the 18 options. Price elasticity is generally believed to increase as any good becomes a greater percentage of disposable income. Other things being equal if a customer is in block two electricity costs will form a higher share of disposable income than they would if the customer experienced only block one levels of consumption. Thus it can be inferred that price elasticity should be higher in block two than in block one.