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1.0 Reference: F07/F08 RRA (Exhibit B-5-1), Chapter 4, s.4.2.2 Threshold Test re UCA s.45(6.2)(b) filings

- 1.1.1 Does the two-part threshold test for BC Hydro to seek a BCUC determination under UCA s.45(6.2)(b) regarding “all capital expenditures” include commitments (or proposed commitments) by BC Hydro under an electricity supply agreement? If ESA commitments are not considered capital expenditures, please explain how BC Hydro treats them for accounting/regulatory purposes.

RESPONSE:

Neither the costs BC Hydro incurs with respect to development of energy calls nor the costs BC Hydro incurs under energy supply contracts are capitalized and therefore would not be included in a capital plan. Rather they are expensed as they are incurred.

The 2006 LTAP includes a plan under section 45(6.1)(b), and BC Hydro is seeking in the LTAP determinations under section 45(6.2)(b) of the UCA with respect to the expenditures required to undertake and complete Identification and Definition phase work for the F2007 call and Identification phase work for the F2009 call.

The energy supply contracts that result from calls are filed with the BCUC under section 71(1) of the UCA (which permits but does not require the Commission to hold a hearing into such contracts). Costs incurred by BC Hydro pursuant to executed energy supply contracts are reviewed in BC Hydro's revenue requirement proceedings. Given that expenditures pursuant to executed energy supply contracts arise long after plans are put in place to acquire energy from other persons, and that the contracts themselves are subject to the filing requirements of the UCA, it is BC Hydro's view that the expenditures arising from existing executed energy supply contracts may but need not be described in plans filed in compliance with section 45(6.1)(b).

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2.0 Reference: BC Hydro IEP/LTAP Application, BCUC Project No. 3698419, Exhibit B-10, BC Hydro Response to SCCBC, et al IR 1.1.3.

- 1.2.1 Is it BC Hydro's position that the "expenditures required" for acquiring energy from other persons, within the meaning of UCA s.45(6.1)(b), does not include BC Hydro's cost of purchasing the energy? If so, please provide the rationale.

RESPONSE:

Please refer to the response to SCCBC IR 1.1.1.

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3.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, p.1,7

“2. Program cost-effectiveness must be demonstrated:

- The program must pass the All Ratepayers Test (formerly the Total Resource Cost or TRC).
- The portfolio Utility Test (levelized) should be less than \$0.025/kWh to ensure sharing of DSM costs between BC Hydro and participating customers.
- The Non-Participant Test (formerly the Ratepayer Impact Measure or RIM) result is reviewed to understand the potential impact on non-participants.” [p.1, underline added]

“- The Utility Test, indicates the cost-effectiveness of a DSM program or portfolio from BC Hydro’s perspective” [p.7, underline added]

1.3.1 Please define in detail the All Ratepayers Test, the Non-Participant Test, and the Utility Test.

RESPONSE:

For detail on the All Ratepayers Test, please refer to the attached response to BCUC IR 1.76.1 in the 2006 IEP and LTAP proceedings.

For detail on the Non-Participant Test, please refer to the attached response to BCUC IR 1.278.2 in the 2006 IEP and LTAP proceedings.

For detail on the Utility Test, please refer to the attached response to BCUC IR 1.278.5 in the 2006 IEP and LTAP proceedings.

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76.0 Reference: Exhibit B-1A, p. 4-20

- 1.76.1 Please define the all-ratepayers test and provide the formula used to calculate the test.

RESPONSE:

The All Ratepayers Test, also known as the TRC test, compares the total benefits of DSM to the sum of utility and customer costs. It indicates whether DSM produces net benefits or costs for ratepayers as a whole.

The formula for the All Ratepayers Test benefit – cost ratio is as follows:

$$\frac{\text{PV (Avoided energy supply costs + customer non-energy benefits)}}{\text{PV (Utility non-incentive costs + customer costs)}}$$

where avoided energy supply costs encompass electricity and other fuels (such as natural gas) and PV means present value.

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278.0 Reference: Exhibit B-1C, Appendix L, pp. 23 - 32

1.278.2 Please describe the calculation of the Ratepayer Impact Measure (RIM) and provide the formula used by BC Hydro to calculate the RIM.

RESPONSE:

The Ratepayer Impact Measure, also known as the Non-Participant Test Cost, compares the utility benefits of DSM to the sum of utility costs and lost revenues. It indicates whether DSM causes electricity rates to increase or decrease, and therefore the impact on DSM non-participants, who do not experience a reduction in electricity consumption that would offset any rate increase.

The formula for the Ratepayer Impact Measure benefit-cost ratio is as follows:

$$\frac{\text{PV (Avoided electricity supply costs)}}{\text{PV (Utility DSM costs + lost revenues)}}$$

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278.0 Reference: Exhibit B-1C, Appendix L, pp. 23 - 32

1.278.5 Please provide the formula used by BC Hydro to calculate the Utility Cost Test.

RESPONSE:

The formula for the Utility Cost test benefit-cost ratio is as follows:

$$\frac{\text{PV (Avoided electricity supply costs)}}{\text{PV (Utility DSM costs)}}$$

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3.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, p.1,7

“2. Program cost-effectiveness must be demonstrated:

- The program must pass the All Ratepayers Test (formerly the Total Resource Cost or TRC).
- The portfolio Utility Test (levelized) should be less than \$0.025/kWh to ensure sharing of DSM costs between BC Hydro and participating customers.
- The Non-Participant Test (formerly the Ratepayer Impact Measure or RIM) result is reviewed to understand the potential impact on non-participants.” [p.1, underline added]

“- The Utility Test, indicates the cost-effectiveness of a DSM program or portfolio from BC Hydro’s perspective” [p.7, underline added]

1.3.2 What, if any, are the differences between the All Ratepayers Test and the former Total Resource Cost?

RESPONSE:

Please refer to the response to BCUC IR 1.45.1.

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3.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, p.1,7

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“- The Utility Test, indicates the cost-effectiveness of a DSM program or portfolio from BC Hydro’s perspective” [p.7, underline added]

1.3.3 What, if any, are the differences between the Non-Participant Test and the former Ratepayer Impact Measure?

RESPONSE:

Please refer to the response to BCUC IR 1.45.1.

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- The Non-Participant Test (formerly the Ratepayer Impact Measure or RIM) result is reviewed to understand the potential impact on non-participants.” [p.1, underline added]

“- The Utility Test, indicates the cost-effectiveness of a DSM program or portfolio from BC Hydro’s perspective” [p.7, underline added]

- 1.3.4 Please explain the methodology by which BC Hydro arrived at the portfolio Utility Test figure of “\$0.025/kWh” as being the point at which it is ensured that DSM costs are shared between BC Hydro and participating customers.

RESPONSE:

Please refer to the response to BCUC IR 1.123.2.

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- The Non-Participant Test (formerly the Ratepayer Impact Measure or RIM) result is reviewed to understand the potential impact on non-participants.” [p.1, underline added]

“- The Utility Test, indicates the cost-effectiveness of a DSM program or portfolio from BC Hydro’s perspective” [p.7, underline added]

1.3.5 Please outline the pros and cons of setting the DSM portfolio Utility Test at the “avoided electricity supply cost” referenced on p.7.

RESPONSE:

Pros:

- **BC Hydro could potentially achieve more DSM electricity savings.**

Cons:

- **The impact on DSM non-participants would be greater.**

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- The Non-Participant Test (formerly the Ratepayer Impact Measure or RIM) result is reviewed to understand the potential impact on non-participants.” [p.1, underline added]

“- The Utility Test, indicates the cost-effectiveness of a DSM program or portfolio from BC Hydro’s perspective” [p.7, underline added]

1.3.6 How does the portfolio Utility Test compare with “BC Hydro Costs” defined on p.6?

RESPONSE:

Total BC Hydro Costs (Table 5 in Appendix P) are included in the calculation of the Utility Test.

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4.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, p.6

“Customer Costs These include the full cost to the customer of the energy efficiency improvement, or the incremental cost of the energy efficient option relative to the standard option where applicable.”

- 1.4.1 Does “Customer Costs” include an adjustment for reduced electricity costs associated with the energy efficiency improvement? If not, why not?

RESPONSE:

No. Proper cost-effectiveness analysis of DSM requires a clear separation of costs and benefits. Subtracting electric bill savings from customer costs would underestimate the cost of DSM in the All Ratepayers Test.

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5.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, p.6

“All Ratepayers Costs All Ratepayers Costs are the sum of BC Hydro non-incentive costs and customer costs.”

1.5.1 Why are BC Hydro’s incentive costs not included in “All Ratepayers Costs”?

RESPONSE:

Including BC Hydro incentive costs in All Ratepayers Costs would result in an inappropriate double-counting.

DSM incentives are a financial transfer from BC Hydro to participating customers. So long as customer costs capture the full cost of DSM measures to participating customers, incentive costs should not be included in All Ratepayers Costs. If BC Hydro incentive costs were included in All Ratepayers Costs, those incentive costs would need to be subtracted from customer costs to avoid double-counting.

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5.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, p.6

“All Ratepayers Costs All Ratepayers Costs are the sum of BC Hydro non-incentive costs and customer costs.”

- 1.5.2 Does “All Ratepayers Costs” equal “Utility Test” plus “Customer Costs” minus BC Hydro’s incentive costs? If not, please reconcile the various measures.

RESPONSE:

No. All Ratepayers Costs do not equal BC Hydro total costs plus customer costs minus BC Hydro incentive costs.

Please refer to the response to BCUC IR 1.46.0 for a more detailed description of the contents of All Ratepayers Costs.

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6.0 Reference: Exhibit B-5-1, p. 4-7, lines 5 – 7; and p. 4-6, Table 4-3, Capital Expenditure Summary – Growth.

“The significant changes in the capital forecast for the test years include: ...

A reduction in growth investment for Power Smart of 56 per cent in F2007 due to a reduction in incentives for large industrial customers as an anticipated result of new stepped rates.” [p. 4-7]

- 1.6.1 Is the reduction in proposed Power Smart Capital Expenditure from \$125-million in F2006 REAP to \$55-million in F2007 Plan and \$57-million F2008 Plan due entirely to the reduction in incentives for large industrial customers as an anticipated result of new stepped rates? If not, please quantify and explain other reasons for the proposed decline.

RESPONSE:

No, the reduction from the 2005 REAP figure of \$125 million for F2006 to the F07/F08 RRA figure of \$55 million for F2007 is largely due to the following reasons:

- **\$46.0 million due to the incentive payment for the Canfor load displacement project being accounted for in F2006;**
- **\$14.1 million due to a reduction in incentive payments to other industrial customers, due to the introduction of stepped rates;**
- **\$4.5 million due to the cancellation of the Lighting Redesign program;**
- **\$2.4 million due to a reduction in the Compact Fluorescent Lighting program’s costs; and**
- **\$2.1 million due to a reduction in the Schools, Universities, Colleges and Hospitals program’s costs.**

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“The significant changes in the capital forecast for the test years include: ...

A reduction in growth investment for Power Smart of 56 per cent in F2007 due to a reduction in incentives for large industrial customers as an anticipated result of new stepped rates.” [p. 4-7]

1.6.2 What would be the Power Smart Capital Expenditure in F2007 Plan and F2008 Plan if Power Smart incentives to large industrial customers were not reduced?

RESPONSE:

An analysis of the required capital expenditures without the new stepped rates structure in place was not done. When the Capital Expenditure Plan was being developed, the stepped rates structure had already been approved by the BCUC, so a scenario without stepped rates was not developed.

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7.0 Reference: Exhibit B-5-1, Table 8-35, Distribution Capital Programs and Projects Greater Than \$2 Million, page 8-82: “Demand Side Management – Existing [FN: Deferred capital only.]”

- 1.7.1 Please explain the footnote “Deferred capital only” qualifying “Demand Side Management – Existing”.

RESPONSE:

Please refer to the response to BCUC IR 1.107.1.

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7.0 Reference: Exhibit B-5-1, Table 8-35, Distribution Capital Programs and Projects Greater Than \$2 Million, page 8-82: “Demand Side Management – Existing [FN: Deferred capital only.]”

1.7.2 In the absence of a reduction in growth investment for Power Smart attributable to the implementation of stepped rates for transmission class customers, what effect would there be on Power Smart’s Total Gross Capital for F2007, F2008 and F2009; and what effect would there be on the EE3, EE4 and EE5 planned expenditures for F2008 and F2009?

RESPONSE:

In the absence of stepped rates, the Total Gross Capital expended by BC Hydro in F2007, F2008 and F2009 would have been higher. As described in the response to SCCBC IR 1.6.2, the specific magnitude of this impact was not analyzed.

Similarly, the effect of the absence of stepped rates will not be assessed during the Definition Phase of EE 3, 4 and 5, but it can be presumed that the required incentive expenditures for F2008 and F2009 would have been higher without stepped rates.

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8.0 Reference: Exhibit B-5-1, Table 8-35, Distribution Capital Programs and Projects Greater Than \$2 Million, page 8-83: “EE3, EE4, EE5”

The line item “EE3, EE4, EE5” shows \$24.0 million for F2008 Plan and \$24.6 million for F2009 Plan. Under “Phase” this line is labeled “Identification/Definition.”

1.8.1 Please explain this proposed expenditure.

RESPONSE:

Please refer to the response to BCUC IR 1.27.1.

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9.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, p.7

“The Lighting Redesign program in the commercial sector was never launched and has been cancelled after further analysis and experience indicated that it would not be cost-effective.”

- 1.9.1 Was the Lighting Redesign program analyzed using the All Ratepayers Test, the Non-Participant Test, and the Utility Test? If so, please provide details of the results. If not, please explain why not.

RESPONSE:

The Lighting Redesign program was analyzed using the All Ratepayers Test (TRC), the Non-participant Test (RIM), and the Utility Test. The benefit cost ratio results were as follows:

**All Ratepayers Test: 0.7
Non-participant Test: 0.8
Utility Test: 1.6**

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“The Lighting Redesign program in the commercial sector was never launched and has been cancelled after further analysis and experience indicated that it would not be cost-effective.”

- 1.9.2 Please discuss how the term “cost-effective” used in the cancellation of the Lighting Redesign program compares with the All Ratepayers Test, the Non-Participant Test, and the Utility Test.

RESPONSE:

The Lighting Redesign program was not launched because it was not cost effective based on the All Ratepayers Test (TRC) benefit cost ratio of 0.7.

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10.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, p.7

“The industrial Power Smart Partners Program has been modified in light of the new Transmission Service Rates that will take effect in April 2006. Financial incentives for customer projects that reduce the customer’s consumption of Tier 2 electricity have been eliminated due to the price signal delivered by the Tier 2 price. Program enabling activities have been redesigned to support customers responding to the Tier 2 price signal with energy efficiency projects.”

1.10.1 Please provide the rationale for the elimination of financial incentives for customer projects that reduce the customer’s consumption of Tier 2 electricity. Was the decision based on conceptual grounds, or empirical grounds (or both)?

RESPONSE:

Please refer to the response to JIESC 1.44.2.

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1.10.2 What does “Program enabling activities” refer to in the above context?

RESPONSE:

Program enabling activities refer to Power Smart Partners program components other than incentives for capital projects. The components are described in Appendix R, page 4-6 under the headings People, Process, Technology, and Program Enabling Initiatives.

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1.10.3 What effect has the new Transmission Service Rates had on energy efficiency and electricity demand by transmission level customers?

RESPONSE:

The new Transmission Service Rates were launched on April 1, 2006. As a result, it is too soon to quantify the effect that these rates have had on energy efficiency and electricity demand.

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11.0 Reference: Energy for Our Future: A Plan for BC, Policy Action # 14, suppliers to large electricity consumers

Policy Action #14 states:

“Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.

“New stepped pricing (see Conservation and Efficiency) will provide an incentive for large industrial or transmission rate customers to purchase from IPPs, or to self-generate, when they can do so less expensively than the utility’s cost of new supply. These larger customers will be able to meet all or a portion of their consumption from private generation. This policy change introduces retail competition for large BC Hydro customers. Aquila Networks Canada already offers retail access to its industrial customers.”

1.11.1 What effects, if any, has Policy Action #14 had on the F07/F08 RRA?

RESPONSE:

Introduction of the stepped rates led to a reduction in planned DSM incentive costs. Please see the response to BCUC IR 1.25.4.

Stepped rates also impacted the forecast of DSM electricity savings and, in turn, forecast load and revenue. Please see the response to BCUC IR 1.25.5 for a description of the DSM electricity savings forecasting methodology under stepped rates and the response to BCUC IR 1.67.2 for a description of the load and revenue forecasting methodology under stepped rates.

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1.11.2 What effects does BC Hydro anticipate that Policy Action #14 will have on the planning and delivery of DSM programs?

RESPONSE:

Stepped rates provide a stronger price signal for energy conservation and load displacement among transmission customers than the previous flat rate. Recognizing this, BC Hydro eliminated DSM incentives for capital projects that save Tier 2 energy and modified DSM programs targeting transmission customers so as to facilitate their responding to the Tier 2 price signal with energy conservation and load displacement projects.

Please see the response to BCUC IR 1.25.5 for a description of the estimation of electricity savings and DSM incentives under stepped rates.

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12.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, Tables

- 1.12.1 Please confirm that the tables relate only to “Energy Efficiency 2” programs. If not, please provide similar tables, breaking down expenditures by EE2, EE3, EE4 and EE5, as applicable.

RESPONSE:

Confirmed.

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13.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, Table 1, Net Incremental Electricity Savings at Customer Meter (GWh/yr), p.9, Table 2 Net Cumulative Electricity Savings at Customer Meter (GWh/yr), p.12.

1.13.1 Should these tables be expressed as 'GWh by year' rather than "GWh/yr"?

RESPONSE:

No, the numbers in these tables are appropriately expressed as GWh per year.

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13.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, Table 1, Net Incremental Electricity Savings at Customer Meter (GWh/yr), p.9, Table 2 Net Cumulative Electricity Savings at Customer Meter (GWh/yr), p.12.

1.13.2 What does a negative net incremental electricity savings (or a declining net cumulative electricity savings) mean?

RESPONSE:

Please refer to the response to BCUC IR 1.126.1.

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14.0 Reference: Exhibit B-5-3, Appendix P, Energy Efficiency Plan, April 6, 2006, Table 6, Customer Costs, p.18

1.14.1 Please explain the substantial year to year variations in each of the programs.

RESPONSE:

Customer Costs vary year to year for some of BC Hydro's DSM programs because these costs are related to the amount of participation activity and the types of technologies being implemented, which also varies from year to year. In addition to the variation of upfront customer capital costs over time, replacement costs are also included in future years where appropriate.

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15.0 Reference: Exhibit B-5-3, Appendix R, p. 34, Residential Fuel Substitution Program.

1.15.1 Where, besides Vancouver Island, is the Residential Fuel Substitution Program being implemented or planned to be implemented?

RESPONSE:

The Residential Fuel Substitution Program, outlined in Appendix R, is only being implemented, or planned to be implemented on Vancouver Island and parts of the Sunshine Coast.

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15.0 Reference: Exhibit B-5-3, Appendix R, p. 34, Residential Fuel Substitution Program.

- 1.15.2 Please describe and quantify the respective contributions of the named partners: Terasen Gas, Natural Resources Canada and the B.C. Ministry of Energy, Mines and Petroleum Resources.

RESPONSE:

For the space heating portion of the program, BC Hydro and Terasen Gas each contribute \$250 towards a customer incentive and \$25,000 annually for marketing and promotions. For F2006, Natural Resources Canada (NRCan) and the Ministry of Energy Mines and Resources (MEMPR) contributed to the same level as the other partners.

For the water heating portion of the program BC Hydro and Terasen Gas each contribute \$200 towards a customer incentive and \$40,000 annually towards marketing and promotion.

In addition to the contributions described above, BC Hydro and Terasen Gas each incur additional labour and administrative costs related to the Fuel Substitution Program. Please refer to the response to SCCBC IR 1.16.2.

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16.0 Reference: Exhibit B-5-3, Appendix P, Tables 1 – 9, Residential Sector, Fuel Substitution.

- 1.16.1 In Table 6, Customer Costs, for Fuel Substitution, does the figure include the customer's cost of additional natural gas due to switching from electricity to natural gas? Please provide a similar table for Customer Costs for Fuel Substitution by Year either broken down by natural gas costs (if they are included) and other costs or with the additional of customer natural gas costs (if they are not included).

RESPONSE:

No, the Fuel Substitution Program figures in Table 6 do not include the cost of incremental natural gas consumption. They represent the incremental upfront cost (equipment and installation) and non-energy cost (monthly fixed gas charges among selected Fuel Substitution program participants) of the DSM measure to the customer.

To capture the added natural gas resource cost of the Fuel Substitution Program, incremental natural gas supply costs are included in the All Ratepayers Test. Please refer to the response to SCCBC IR 1.16.3.

The following table presents the customer costs (from Table 6) and incremental customer gas bill fuel costs for the Fuel Substitution Program.

(\$ thousand)	F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017
Customer costs	-	145	655	677	958	1,266	1,499	1,762	1,637	1,864	658	671	685	698	771
Incremental customer gas bill fuel costs	-	12	95	306	813	1,184	1,765	2,452	3,222	4,077	4,439	4,562	4,692	4,807	4,896
Total	-	157	750	984	1,771	2,450	3,263	4,213	4,859	5,941	5,097	5,233	5,376	5,505	5,668

(\$ thousand)	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Customer costs	786	820	850	882	896	912	818	834	851	868	936	953	988	1,020
Incremental customer gas bill fuel costs	4,975	5,075	5,173	5,257	5,325	5,383	5,482	5,619	5,760	5,744	5,728	5,635	5,513	5,347
Total	5,760	5,895	6,024	6,139	6,221	6,294	6,300	6,454	6,611	6,612	6,664	6,589	6,501	6,367

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16.0 Reference: Exhibit B-5-3, Appendix P, Tables 1 – 9, Residential Sector, Fuel Substitution.

1.16.2 In Table 7, All Ratepayers Costs, for Fuel Substitution, does the figure include costs incurred by Terasen Gas (other than the customer's cost of natural gas)? Please provide a similar table for All Ratepayers Costs for Fuel Substitution by Year broken down by, or adding, Terasen Gas's costs, customer gas costs, and other costs.

RESPONSE:

Yes, the Fuel Substitution program's All Ratepayers Costs in Table 7 include Terasen Gas costs.

The following table provides a breakdown of the Fuel Substitution program's All Ratepayers Costs.

Costs have been updated to include partner organization program costs in F2004 – F2007 that were inadvertently omitted and to correct a misallocation of partner organization program costs as BC Hydro program costs in F2006 – F2012. As a result of the omission of \$367,000 in partner organization program costs in F2004 – F2007, total All Ratepayers Costs in the following table do not equal those in Table 7 of Appendix P.

The updates result in small changes to the program's cost test results. The Utility Test benefit-cost ratio increases from 8.3 to 9.1. The All Ratepayers Test benefit-cost ratio decreases from 2.5 to 2.4. The Non-Participant Test benefit-cost ratio remains unchanged at 1.1.

BC Hydro, Terasen Gas and Natural Resources Canada incentive costs are not included in All Ratepayers Costs because customer costs are gross costs before incentives.

Please see the table in the response to SCCBC IR 1.16.1 for customer gas costs.

(\$ thousand)	F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017
BC Hydro program costs	-	65	57	160	135	130	133	135	138	140	-	-	-	-	-
Customer costs	-	145	655	677	958	1,266	1,499	1,762	1,637	1,864	658	671	685	698	771
Terasen Gas program costs	-	65	58	160	135	130	133	135	138	140	-	-	-	-	-
BC Ministry of Energy, Mines and Petroleum Resources program costs	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-
Natural Resources Canada program costs	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-
Total	-	275	770	1,047	1,228	1,526	1,765	2,032	1,913	2,144	658	671	685	698	771

(\$ thousand)	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
BC Hydro program costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer costs	786	820	850	882	896	912	818	834	851	868	936	953	988	1,020
Terasen Gas program costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BC Ministry of Energy, Mines and Petroleum Resources program costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Resources Canada program costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	786	820	850	882	896	912	818	834	851	868	936	953	988	1,020

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16.0 Reference: Exhibit B-5-3, Appendix P, Tables 1 – 9, Residential Sector, Fuel Substitution.

- 1.16.3 In Table 9, Cost Test Results, for Fuel Substitution, do the Utility Test, All Ratepayers Test and Non-Participant Test factor in customer gas costs and Terasen Gas's costs? If not, please provide a similar table for Cost Test Results for Fuel Substitution factoring in customer gas costs and Terasen Gas's costs.

RESPONSE:

Customer natural gas fuel costs are not included in any of the three tests in Table 9. In the case of the Utility and Non-Participant Tests, this is because they evaluate DSM from the perspective of BC Hydro and BC Hydro customers who do not participate in that program, respectively. Customer natural gas fuel costs are not relevant to either of these two perspectives. In the case of the All Ratepayers Test, the cost of incremental natural gas supply is included, in keeping with standard DSM cost-effectiveness analysis methodology.

Terasen Gas costs are not included in either the Utility Test or the Non-Participant Test because they evaluate DSM from the perspective of BC Hydro and BC Hydro customers who do not participate in that program, respectively. Terasen Gas costs are not relevant to either of these two perspectives. Terasen Gas costs are included in the All Ratepayers Test, in keeping with standard DSM cost-effectiveness analysis methodology.

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16.0 Reference: Exhibit B-5-3, Appendix P, Tables 1 – 9, Residential Sector, Fuel Substitution.

1.16.4 Has BC Hydro assessed the value to Terasen Gas of BC Hydro's Fuel Substitution program? If so, please give a summary of the results.

RESPONSE:

No, BC Hydro has not assessed the value to Terasen Gas of BC Hydro's Fuel Substitution program.

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17.0 Reference: RRA (Exhibit B-5-3), Appendix Q: Load Displacement

- 1.17.1 Please list and describe the load displacement projects BC Hydro plans for F2007 and F2008.

RESPONSE:

Please refer to the response to BCUC IR 1.131.0.

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17.0 Reference: RRA (Exhibit B-5-3), Appendix Q: Load Displacement

- 1.17.2 What is the current status of the proposed load displacement project at the Gibraltar Mine involving micro-hydroelectric generation utilizing supernatant from the tailings impoundment being piped down to the Fraser River?

RESPONSE:

Gibraltar Mines initiated permitting work on the load displacement project, but did not proceed on the timeline agreed upon in BC Hydro's Incentive Agreement. As a result, the Incentive Agreement has been terminated. BC Hydro will be working with Gibraltar Mines to encourage continuation of the project under stepped rates.

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18.0 Reference: F07/F08 RRA (Exhibit B-5-3), Appendix R, Market Barriers

The evidence for industrial, commercial and residential programs discusses “Market Barriers” for each Power Smart program. In most cases, “Awareness & Understanding” is an item.

- 1.18.1 For each Power Smart program listed, please indicate the importance of awareness and understanding relative to other market barriers.

RESPONSE:

For all programs, awareness and understanding are key foundational pieces to success. If the awareness and understanding barrier is not overcome, customers will not implement energy efficiency measures.

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18.0 Reference: F07/F08 RRA (Exhibit B-5-3), Appendix R, Market Barriers

The evidence for industrial, commercial and residential programs discusses “Market Barriers” for each Power Smart program. In most cases, “Awareness & Understanding” is an item.

- 1.18.2 For each Power Smart program listed, please discuss (quantitatively, if possible) the sensitivity of awareness and understanding among customers to increased or decreased expenditures by Power Smart on this item.

RESPONSE:

For each program, customers react to the overall offer, marketing mix, and presence of other barriers as opposed to individual components in isolation.

The sensitivity of awareness and understanding to changes in expenditure levels has not been specifically measured by BC Hydro for each program.

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19.0 Reference: Exhibit B-5-3, Appendix R, Energy Efficiency Program Summaries; Cancellation of federal energy efficiency programs

- 1.19.1 Please discuss the impact of the cancellation of federal energy efficiency programs on the BC Hydro programs such as the New Home Program, the Renovation Rebate Program the Variable Speed Furnace Blower Motors Program, and Residential Enabling Initiatives.

RESPONSE:

The cancellation of the federal energy efficiency programs has had no impact on BC Hydro's residential DSM programs.

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20.0 Reference: Exhibit B-5-3, Appendix S, DSM Program Evaluation Summary and Plan

- 1.20.1 Please discuss whether and how BC Hydro's evaluation of its DSM programs provides information regarding opportunities for cost-effective expansion of existing programs or development of new DSM programs.

RESPONSE:

BC Hydro's DSM evaluations focus on three areas:

- **Process evaluation, which examines the operation of the program in the early stage after it is launched, to determine if there are areas where the program can be made more effective;**
- **Market evaluation, which primarily examines what impact the program has had on the market, and attributes savings from market effects;**
- **Impact Evaluation, which determines the net to gross ratio, so as to determine the results attributable to the DSM program.**

DSM program evaluations make a number of recommendations on the issues addressed by the above types of evaluations. Sometimes, recommendations dealing with opportunities for the cost-effective expansion of existing programs or development of new programs are included.

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21.0 Reference: RRA (Exhibit B-5-3), Appendix T: DSM Programs with Non-Participant Benefit-Cost Ratios Below 0.8

“The average cost per residential customer is what this rate increment works out to for the average non-participating residential customer on an annual basis.”
[p.1, underline added]

- 1.21.1 Does the measure “Average Cost per Residential Customer” include all residential customers (whether participating or not) or is it restricted to residential customers who do not participate in the program?

RESPONSE:

The measure “Average Cost per Residential Customer” applies to all residential customers, and assumes no change in the consumption of the average residential customer. Since non-participants in the specified DSM program see no change in their electricity consumption, “Average Cost per Residential Customer” represents the average increase in their annual electricity bill, other things being equal. Participants in the specified DSM program see a reduction in their electricity consumption that more than offsets the rate increment. So even though they too incur the “Average Cost per Residential Customer,” the DSM program reduces their annual electricity bill on a net basis, other things being equal.

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21.0 Reference: RRA (Exhibit B-5-3), Appendix T: DSM Programs with Non-Participant Benefit-Cost Ratios Below 0.8

“The average cost per residential customer is what this rate increment works out to for the average non-participating residential customer on an annual basis.”
[p.1, underline added]

1.21.2 Does the measure “Average Rate Increment” in Table 1 include all customer classes or just the residential customer class?

RESPONSE:

The measure “Average Rate Increment” applies to all customer classes.

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21.0 Reference: RRA (Exhibit B-5-3), Appendix T: DSM Programs with Non-Participant Benefit-Cost Ratios Below 0.8

“The average cost per residential customer is what this rate increment works out to for the average non-participating residential customer on an annual basis.”
[p.1, underline added]

1.21.3 Table 1 shows only residential customer costs for the Refrigerator Buy-Back program. Does the Non-Participant Test (or RIM) measure ratepayer cost impacts only within the customer class to which a DSM program is offered? If not, please characterize the cross-class cost impacts of the DSM programs cited in response to the preceding IR.

RESPONSE:

No, the Non-Participant Test indicates the impact on all DSM non-participants, regardless of customer class.

The cross-class impact of the Refrigerator Buy-Back program represents the Average Rate Increment indicated in Table 1 applied to non-residential customer classes.

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21.0 Reference: RRA (Exhibit B-5-3), Appendix T: DSM Programs with Non-Participant Benefit-Cost Ratios Below 0.8

“The average cost per residential customer is what this rate increment works out to for the average non-participating residential customer on an annual basis.”
[p.1, underline added]

- 1.21.4 Please list any DSM programs identified by BC Hydro that have (or had) a Non-Participant Test under 0.8 and that did not become active programs. Please include potential programs in the residential, commercial and industrial sectors. For each such program, please provide a program description and provide figures for Non-Participant Test Benefit-Cost Ratio, Average Rate Increment and Average Cost per Customer Class Customer.

RESPONSE:

BC Hydro has not to date identified any programs in the residential, commercial or industrial sectors that did not become active because of the non-participant test benefit-cost ratio being less than 0.8.

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22.0 Reference: RRA (Exhibit B-5-3), Appendix U: Justification for DSM Portfolio Level Costs

- 1.22.1 Please confirm that the Portfolio Level Costs discussed for the F2007 and F2008 plan are relevant to all of EE2, LD2, EE3, EE4 and EE5. If not, please explain and detail how the F2007 and F2008 costs are differently relevant to the different Power Smart programs, distinguishing between “Public Awareness & Information” and “Portfolio Enabling Activities.”

RESPONSE:

The types of activities that make up the Portfolio Level Costs included in the F2007 and F2008 Plans, and discussed in Appendix U, are relevant to all of EE2, LD2, EE3, EE4 and EE5 but the specific costs were planned based on EE2 and LD2 only. The specific costs are not relevant to EE 3, 4 and 5. Any changes required to the Portfolio Level Costs to support EE 3, 4 and 5 will be determined through the Definition Phase of EE 3, 4 and 5.

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22.0 Reference: RRA (Exhibit B-5-3), Appendix U: Justification for DSM Portfolio Level Costs

- 1.22.2 Please characterize the Portfolio Enabling Activities more fully and explain the distinction between them and PowerSmart's OMG&A costs.

RESPONSE:

Power Smart OMG&A includes general administrative and operations expenses which do not directly or indirectly support the existing Power Smart DSM Plan, but which are required to support the Power Smart business unit and its staff. These include rent, office supplies, general staff training, education and management, customer data collection and analysis, and also costs associated with planning and studies to assist in the definition and design of future DSM programs, such as EE 3, 4 and 5.

Portfolio Enabling activities support Power Smart's existing DSM Plan, including management, tracking and reporting, planning, internal control, and quality assurance requirements for the Energy Efficiency and Load Displacement programs. Please refer to the response to BCUC IR 1.50.1 for greater detail on Portfolio Enabling activities.

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22.0 Reference: RRA (Exhibit B-5-3), Appendix U: Justification for DSM Portfolio Level Costs

- 1.22.3 Have the costs given for F2007 and F2008, both for Public Awareness & Information and Portfolio Enabling Activities, been determined with any assumptions in mind about the extent and scope of EE3, 4 & 5, or any potential new Power Smart program planning that might arise from the 2007 update to the Conservation Potential Review? Might such new Power Smart program planning give rise to a need for more Public Awareness & Information and Portfolio Enabling Activities?

RESPONSE:

No, the Public Awareness & Information and the Portfolio Enabling Activities costs for F2007 and F2008 support the DSM activity outlined in Appendices P and Q.

BC Hydro has provided an overall provisional estimate for an additional \$24 million in F2008 for the implementation of EE 3, 4, and 5. A better estimate of the implementation costs, including Public Awareness & Information and Portfolio Enabling Activities, will be determined through the Definition Phase of EE 3, 4 and 5.

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22.0 Reference: RRA (Exhibit B-5-3), Appendix U: Justification for DSM Portfolio Level Costs

1.22.4 How does BC Hydro determine if its DSM expenditures in this area are enough, too little or more than necessary?

RESPONSE:

Please refer to the response to BCUC IR 1.50.3 for a discussion of the planning for Public Awareness and Information activities.

Portfolio Enabling Activities provide the organizational support, infrastructure, quality assurance, planning, reporting and governance required to ensure that BC Hydro's DSM plan is properly managed. Requirements are determined in part by structural requirements of the DSM plan, program activity, and the requirements of stakeholders and customers. Included in these activities are expenditures for computer and information systems that are necessary to properly plan, track and report on DSM activity, and also to provide information and analysis required by BC Hydro, customers and other stakeholders.

BC Hydro prepares annual budgets for Portfolio Enabling Activities at the department level, based on a review of planned DSM program activity, and historical information and trends. BC Hydro also considers anticipated requirements to properly support the DSM Plan and its stakeholders in the future, based on expected plan activity and stakeholder needs. Department budgets are developed and reviewed within the overall DSM planning process, and are included in the DSM cost tests.

In addition, Portfolio Enabling budgets are reviewed as part of the overall review of DSM capital plans within Distribution.

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23.0 References: 2006 IEP & LTAP (Exhibit B-1A), pp. 8-32 & 8-33; and F07/F08 RRA (Exhibit B-5-1), pp. 2-35, 2-36 and 5-56

The 2006 IEP & LTAP estimates the costs of Stages 1, 2 and 3 respectively as \$14.7 m, \$20 m and \$14 m (based on a part of Stage 3). The F07/F08 RRA, on page 2-35, gives \$60 m to \$65 m as a possible cost range for Stages 1, 2 and 3, but on page 5-56, gives costs of \$10 m, \$20 m and \$30 m for Stages 1, 2 and 3, respectively, i.e. a total of \$60 m. The 2006 IEP & LTAP (page 8-32) shows Stage 1 costs disaggregated into two components of \$4.7 m and \$10 m. The F07/F08 RRA (page 2-35) cites \$3.9 m as having been spent on Stage 1 in F2006, with a further \$10 m planned to be spent in F2007, while (on page 5-56) shows a “total cost” for Stage 1 of \$10 m. On p 2-36 of the F07/F08 RRA, BC Hydro discusses a regulatory asset account for some of the Site C costs.

1.23.1 Please reconcile and explain these apparently differing cost estimates.

RESPONSE:

Please refer to the response to BCUC IR 1.290.3.

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23.0 References: 2006 IEP & LTAP (Exhibit B-1A), pp. 8-32 & 8-33; and F07/F08 RRA (Exhibit B-5-1), pp. 2-35, 2-36 and 5-56

The 2006 IEP & LTAP estimates the costs of Stages 1, 2 and 3 respectively as \$14.7 m, \$20 m and \$14 m (based on a part of Stage 3). The F07/F08 RRA, on page 2-35, gives \$60 m to \$65 m as a possible cost range for Stages 1, 2 and 3, but on page 5-56, gives costs of \$10 m, \$20 m and \$30 m for Stages 1, 2 and 3, respectively, i.e. a total of \$60 m. The 2006 IEP & LTAP (page 8-32) shows Stage 1 costs disaggregated into two components of \$4.7 m and \$10 m. The F07/F08 RRA (page 2-35) cites \$3.9 m as having been spent on Stage 1 in F2006, with a further \$10 m planned to be spent in F2007, while (on page 5-56) shows a “total cost” for Stage 1 of \$10 m. On p 2-36 of the F07/F08 RRA, BC Hydro discusses a regulatory asset account for some of the Site C costs.

- 1.23.2 Have any of the \$10 m Stage 1 costs planned for F2007 been spent?
When in F2007 are they planned to be spent?

RESPONSE:

Stage 1 costs are currently being incurred.

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23.0 References: 2006 IEP & LTAP (Exhibit B-1A), pp. 8-32 & 8-33; and F07/F08 RRA (Exhibit B-5-1), pp. 2-35, 2-36 and 5-56

The 2006 IEP & LTAP estimates the costs of Stages 1, 2 and 3 respectively as \$14.7 m, \$20 m and \$14 m (based on a part of Stage 3). The F07/F08 RRA, on page 2-35, gives \$60 m to \$65 m as a possible cost range for Stages 1, 2 and 3, but on page 5-56, gives costs of \$10 m, \$20 m and \$30 m for Stages 1, 2 and 3, respectively, i.e. a total of \$60 m. The 2006 IEP & LTAP (page 8-32) shows Stage 1 costs disaggregated into two components of \$4.7 m and \$10 m. The F07/F08 RRA (page 2-35) cites \$3.9 m as having been spent on Stage 1 in F2006, with a further \$10 m planned to be spent in F2007, while (on page 5-56) shows a “total cost” for Stage 1 of \$10 m. On p 2-36 of the F07/F08 RRA, BC Hydro discusses a regulatory asset account for some of the Site C costs.

- 1.23.3 Do all of the Site C Stage 1, 2 and 3 costs fall within the description of Site C costs [p.2-36] that would be capitalized under BC Hydro’s proposal? If not, please

RESPONSE:

BC Hydro does not propose to capitalize costs incurred through F2006 (\$3.9 million of Stage 1 cost). Costs incurred through F2006 have been written off. For costs incurred on Site C in F2007 and in the future, BC Hydro has applied to charge them to a regulatory asset, thereby effectively capitalizing them and allowing for a future application to recover them in rates.

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23.0 References: 2006 IEP & LTAP (Exhibit B-1A), pp. 8-32 & 8-33; and F07/F08 RRA (Exhibit B-5-1), pp. 2-35, 2-36 and 5-56

The 2006 IEP & LTAP estimates the costs of Stages 1, 2 and 3 respectively as \$14.7 m, \$20 m and \$14 m (based on a part of Stage 3). The F07/F08 RRA, on page 2-35, gives \$60 m to \$65 m as a possible cost range for Stages 1, 2 and 3, but on page 5-56, gives costs of \$10 m, \$20 m and \$30 m for Stages 1, 2 and 3, respectively, i.e. a total of \$60 m. The 2006 IEP & LTAP (page 8-32) shows Stage 1 costs disaggregated into two components of \$4.7 m and \$10 m. The F07/F08 RRA (page 2-35) cites \$3.9 m as having been spent on Stage 1 in F2006, with a further \$10 m planned to be spent in F2007, while (on page 5-56) shows a "total cost" for Stage 1 of \$10 m. On p 2-36 of the F07/F08 RRA, BC Hydro discusses a regulatory asset account for some of the Site C costs.

- 1.23.4 Please confirm for exactly what portion and amounts of the above-referenced Site C costs BC Hydro seeks authorization to hold in a regulatory account.

RESPONSE:

Please refer to the response to SCCBC IR 1.23.3.

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23.0 References: 2006 IEP & LTAP (Exhibit B-1A), pp. 8-32 & 8-33; and F07/F08 RRA (Exhibit B-5-1), pp. 2-35, 2-36 and 5-56

The 2006 IEP & LTAP estimates the costs of Stages 1, 2 and 3 respectively as \$14.7 m, \$20 m and \$14 m (based on a part of Stage 3). The F07/F08 RRA, on page 2-35, gives \$60 m to \$65 m as a possible cost range for Stages 1, 2 and 3, but on page 5-56, gives costs of \$10 m, \$20 m and \$30 m for Stages 1, 2 and 3, respectively, i.e. a total of \$60 m. The 2006 IEP & LTAP (page 8-32) shows Stage 1 costs disaggregated into two components of \$4.7 m and \$10 m. The F07/F08 RRA (page 2-35) cites \$3.9 m as having been spent on Stage 1 in F2006, with a further \$10 m planned to be spent in F2007, while (on page 5-56) shows a “total cost” for Stage 1 of \$10 m. On p 2-36 of the F07/F08 RRA, BC Hydro discusses a regulatory asset account for some of the Site C costs.

- 1.23.5 Does BC Hydro intend to make the proposed expenditures on Site C Stages 1, 2 and 3 in the event that the BCUC does not grant authorization to BC Hydro to create a regulatory asset account for Site C?

RESPONSE:

As set out on page 5-53 of the F07/F08 RRA, BC Hydro will not proceed to Stage 2 (or subsequent stages) unless government approval is obtained. BC Hydro has not taken a position regarding any planned expenditures in the event that the BCUC does not grant authorization to create a regulatory asset for Site C expenditures.

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23.0 References: 2006 IEP & LTAP (Exhibit B-1A), pp. 8-32 & 8-33; and F07/F08 RRA (Exhibit B-5-1), pp. 2-35, 2-36 and 5-56

The 2006 IEP & LTAP estimates the costs of Stages 1, 2 and 3 respectively as \$14.7 m, \$20 m and \$14 m (based on a part of Stage 3). The F07/F08 RRA, on page 2-35, gives \$60 m to \$65 m as a possible cost range for Stages 1, 2 and 3, but on page 5-56, gives costs of \$10 m, \$20 m and \$30 m for Stages 1, 2 and 3, respectively, i.e. a total of \$60 m. The 2006 IEP & LTAP (page 8-32) shows Stage 1 costs disaggregated into two components of \$4.7 m and \$10 m. The F07/F08 RRA (page 2-35) cites \$3.9 m as having been spent on Stage 1 in F2006, with a further \$10 m planned to be spent in F2007, while (on page 5-56) shows a “total cost” for Stage 1 of \$10 m. On p 2-36 of the F07/F08 RRA, BC Hydro discusses a regulatory asset account for some of the Site C costs.

- 1.23.6 In the present proceeding, does BC Hydro seek an alternative remedy of an order that Site C Stages 1, 2 and 3 expenditures are within the rate base in the event that the Commission declines to approve BC Hydro’s request for a regulatory asset account for Site C expenditures?

RESPONSE:

Please refer to the response to SCCBC IR 1.23.5.

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23.0 References: 2006 IEP & LTAP (Exhibit B-1A), pp. 8-32 & 8-33; and F07/F08 RRA (Exhibit B-5-1), pp. 2-35, 2-36 and 5-56

The 2006 IEP & LTAP estimates the costs of Stages 1, 2 and 3 respectively as \$14.7 m, \$20 m and \$14 m (based on a part of Stage 3). The F07/F08 RRA, on page 2-35, gives \$60 m to \$65 m as a possible cost range for Stages 1, 2 and 3, but on page 5-56, gives costs of \$10 m, \$20 m and \$30 m for Stages 1, 2 and 3, respectively, i.e. a total of \$60 m. The 2006 IEP & LTAP (page 8-32) shows Stage 1 costs disaggregated into two components of \$4.7 m and \$10 m. The F07/F08 RRA (page 2-35) cites \$3.9 m as having been spent on Stage 1 in F2006, with a further \$10 m planned to be spent in F2007, while (on page 5-56) shows a “total cost” for Stage 1 of \$10 m. On p 2-36 of the F07/F08 RRA, BC Hydro discusses a regulatory asset account for some of the Site C costs.

- 1.23.7 Please discuss the merits and problems of deferring an application for authorization for a regulatory asset account (or deferring application for an order allowing F2007 and F2008 Site C expenditures to be recovered in the rates, as the case may be) until after the Stage 1 information has been completed and made available to the relevant parties. In answering, please address BC Hydro’s appreciation of the interests of government, the Commission and stakeholders in being adequately informed and engaged in the process. Please also address how such a deferral would affect the timely acquisition of resources for the BC Hydro system.

RESPONSE:

BC Hydro currently expenses its site investigation costs rather than capitalizing them. Costs that are expensed in a fiscal period may not be recovered in future periods unless a regulatory asset is created in respect of them. Thus, the problem of deferring the application to create a regulatory asset for F2007 and future Site C costs to another period is to make it impossible to recover them in rates. Creating a regulatory asset in respect of Site C costs does not necessarily mean that BC Hydro will seek recovery of such costs in rates, nor that the BCUC would allow the recovery of such costs in rates. It simply makes it possible for either of those decisions to be made. BC Hydro does not believe this proposed treatment has any bearing on the degree to which its stakeholders are being adequately informed or engaged, nor does such treatment have any bearing on the timely acquisition of resources.

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23.0 References: 2006 IEP & LTAP (Exhibit B-1A), pp. 8-32 & 8-33; and F07/F08 RRA (Exhibit B-5-1), pp. 2-35, 2-36 and 5-56

The 2006 IEP & LTAP estimates the costs of Stages 1, 2 and 3 respectively as \$14.7 m, \$20 m and \$14 m (based on a part of Stage 3). The F07/F08 RRA, on page 2-35, gives \$60 m to \$65 m as a possible cost range for Stages 1, 2 and 3, but on page 5-56, gives costs of \$10 m, \$20 m and \$30 m for Stages 1, 2 and 3, respectively, i.e. a total of \$60 m. The 2006 IEP & LTAP (page 8-32) shows Stage 1 costs disaggregated into two components of \$4.7 m and \$10 m. The F07/F08 RRA (page 2-35) cites \$3.9 m as having been spent on Stage 1 in F2006, with a further \$10 m planned to be spent in F2007, while (on page 5-56) shows a “total cost” for Stage 1 of \$10 m. On p 2-36 of the F07/F08 RRA, BC Hydro discusses a regulatory asset account for some of the Site C costs.

1.23.8 Please detail the expected contents of the Stage 1 report. Will it include an updated, detailed business case for Site C?

RESPONSE:

The purpose of the Stage 1 report is to summarize the current state of knowledge about the Site C project and to support a decision by government of whether or not to proceed to the next stage of the project evaluation.

The report will summarize the following topics:

- **The expected need and resource alternatives;**
- **Historical overview of the project;**
- **Project description and estimated costs;**
- **Environmental impacts;**
- **Stakeholder input from the past as well as current practices and context;**
- **First Nations overview including potential impacts;**
- **Regulatory requirements including process overviews.**

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24.0 Reference: F07/F08 RRA (Exhibit B-5-1), BCUC IR#1 (Exhibit A-9), IR 323.8

The IR requests: "Please provide a more detailed description of the stakeholder engagement and First Nations consultation processes assumed in the estimates for Stages 1, 2 and 3."

- 1.24.1 Please specifically address how the information developed in Stage 1 will be made available to the stakeholders that are being engaged in Stage 2 and to other parties.

RESPONSE:

Please refer to the response to BCUC IR 1.323.8.

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25.0 Reference: F07/F08 RRA (Exhibit B-5-1), Chapter 4, p.4-2

“CPCN applications for extension projects that have been identified by the BCUC as requiring such an application, such as Revelstoke 5 (section 45(5) of the UCA) or that BC Hydro believes should be subject to a CPCN application, such as Site C (should the project get Cabinet approval to proceed).” [underline added]

- 1.25.1 Please explain the underlined portion of the above statement. Does the statement imply that BC Hydro’s position is that there is some legal doubt as to whether a Site C proposal by BC Hydro would require a CPCN application? Does the statement mean that BC Hydro’s position is that a Site C proposal by a proponent other than BC Hydro should be required to obtain a CPCN?

RESPONSE:

Under section 45(5) of the UCA the BCUC may require a public utility to apply for a CPCN in respect of a system extension. Assuming that Cabinet decided that BC Hydro should proceed with the project, and assuming the current regulatory regime, BC Hydro does not believe there is ambiguity about the BCUC's jurisdiction to require BC Hydro to seek a CPCN in regard to Site C, and can not imagine that the BCUC would not exercise its section 45(5) jurisdiction in regard to a proposal by BC Hydro to develop Site C. In addition, the Energy Plan refers to Site C being brought to the BCUC for approval as a source of supply (page 30, under policy action #13). For these reasons, and assuming again the current regulatory regime and a government decision for BC Hydro to proceed with the project, BC Hydro would not wait for the BCUC to make an order under section 45(5). BC Hydro is not willing to speculate on what regulatory processes would be applicable in the event the project was developed by a proponent other than BC Hydro.

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26.0 Reference: F07/F08 RRA (Exhibit B-5-1), Chapter 2; Powerex purchase of coal-fired power plant near Hardin, Montana, from Rocky Mountain Power, a subsidiary of MDU Resources Group

- 1.26.1 Please confirm whether Powerex has purchased a coal-fired generation plant in Montana. If this is correct, please provide summary details and explain how this asset will be used.

RESPONSE:

No, Powerex did not purchase a coal-fired generation plant. Powerex has a contract to purchase the output from this plant.

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27.0 Reference: Energy for Our Future: A Plan for BC (2002), Policy Action #20:

Policy Action #20 states,

“Electricity distributors will pursue a voluntary goal to acquire 50 percent of new supply from BC Clean Electricity over the next 10 years.

“BC Clean electricity refers to alternative energy technologies that result in a net environmental improvement relative to existing energy production. Examples may include small/ micro hydro, wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy, as well as cogeneration of heat and power, energy from landfill gas and municipal solid waste, fuel cells, and efficiency improvements at existing facilities. This broad definition will allow for the development of a diverse range of cost-effective and environmentally responsible resources across the province.

“BC Hydro has already surpassed its voluntary target to meet 10 percent of new energy requirements from clean energy. A goal of 50 percent of new supply between 2002 and 2012 is achievable, given the broader definition of BC Clean electricity. The 50 percent level is expected to push the market for new energy sources. It may raise electricity rates by 0.1 to 0.2 percent per year over the next decade. [underline added]

“The goal will be voluntary so that distributors have the flexibility to acquire electricity at competitive prices. At the same time, the BC Utilities Commission will take the goal into account when overseeing the acquisition process for new resources (see Secure, Reliable Supply). The goal will apply equally to the distribution businesses of BC Hydro, Aquila Networks Canada and other investor-owned utilities. They will develop policies (e.g., net metering and interconnection standards) to achieve the goal.”

1.27.1 Does BC Hydro interpret the 50 percent BC Clean electricity target to mean that acquisition of Clean sources may raise electricity rates by a premium of 0.1 to 0.2 percent above what would be the case if non-BC Clean electricity was acquired? If not, how does BC Hydro interpret the 0.1 to 0.2 percent reference?

RESPONSE:

Yes, it may raise rates by 0.1 to 0.2 per cent.

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27.0 Reference: Energy for Our Future: A Plan for BC (2002), Policy Action #20:

Policy Action #20 states,

“Electricity distributors will pursue a voluntary goal to acquire 50 percent of new supply from BC Clean Electricity over the next 10 years.

“BC Clean electricity refers to alternative energy technologies that result in a net environmental improvement relative to existing energy production. Examples may include small/ micro hydro, wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy, as well as cogeneration of heat and power, energy from landfill gas and municipal solid waste, fuel cells, and efficiency improvements at existing facilities. This broad definition will allow for the development of a diverse range of cost-effective and environmentally responsible resources across the province.

“BC Hydro has already surpassed its voluntary target to meet 10 percent of new energy requirements from clean energy. A goal of 50 percent of new supply between 2002 and 2012 is achievable, given the broader definition of BC Clean electricity. The 50 percent level is expected to push the market for new energy sources. It may raise electricity rates by 0.1 to 0.2 percent per year over the next decade. [underline added]

“The goal will be voluntary so that distributors have the flexibility to acquire electricity at competitive prices. At the same time, the BC Utilities Commission will take the goal into account when overseeing the acquisition process for new resources (see Secure, Reliable Supply). The goal will apply equally to the distribution businesses of BC Hydro, Aquila Networks Canada and other investor-owned utilities. They will develop policies (e.g., net metering and interconnection standards) to achieve the goal.”

1.27.2 Are any costs in the present F07/F08 RRA attributable to a premium in the cost of BC Clean energy above that of non-BC Clean energy?

RESPONSE:

The incremental costs attributable to a premium cost of BC Clean energy above that of non-BC Clean energy is not known. This is because the only energy BC Hydro has acquired since the 2002 Energy Plan came in under the 2002 Call for Green Power Generation which used a competitive bidding process. Specifically, the proponents tendered bid prices that had to be competitive both against other bidders and the established ceiling price. The process provided for a series of adjustments that were applied to the bid price (e.g. location, green, GHG, etc) for both ranking purposes and to determine whether or not the bid exceeded the \$55 per MWh ceiling price (and thus rejected). Although the schedule adjustments

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included a \$5 per MWH adjustment for projects meeting the green criteria (and now the BC Clean energy guideline), the actual incremental cost cannot be ascertained, given both the call design to ensure competition and the contract award on lowest cost ranking.

28.0 Reference: F07/F08 RRA, Appendix A (Exhibit B-5-2), F2006 Service Plan, p.8; Energy for Our Future: A Plan for BC (2002), Policy Action #20

“Fifty percent of load increases after November 2002 are to be met by Clean Energy. The time frame for achieving this target is 10 years to 2013.”

1.28.1 Please provide the most recent available information on the percentage of load increases after November 2002 that have been met by Clean Energy. Please also provide the corresponding quantities.

RESPONSE:

Below is BC Hydro’s progress on meeting the 50 % Clean Energy target.

New Electricity from Clean Energy

	F2004	F2005	F2006
Target (%)	50%	50%	50%
Actual (%)	52%	36%	21%
Quantity (GWh)	614	872	879

The Clean Energy target of 50 per cent of incremental load (which is essentially new supply requirements) is to be achieved over a 10-year period, beginning in F2003 and ending in F2013. Since the establishment of the clean energy target in 2002, all energy acquired has been BC Clean, the percentage figures above represent the actual volume of BC Clean Energy that has come on line or on the grid in that current year against the incremental load for that same year. The annual results will fluctuate with the amount of incremental demand over Fiscal 2003 levels, and the timing, volume and type of actual supply delivered. Since Fiscal 2003 there has been a significant increase in electricity demand due to economic activity. In addition, there has been attrition in the volume of BC Clean Energy delivered relative to that contracted.

Future calls will reflect BC Hydro’s progress towards meeting the target (including the results of subsequent calls in contracting BC Clean Electricity supplies).

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29.0 Reference: F07/F08 RRA, Appendix W (Exhibit B-5-3), p.30

“Looking forward, a new federal government climate change initiative may provide NI communities with opportunities to increase involvement in energy planning and generation. Under this initiative, \$30 million has been earmarked for assisting and supporting the approximately 130 remote, and Aboriginal and northern communities that rely on diesel generation as they work to improve their energy efficiency and adopt alternative energy sources to reduce their dependence on diesel fuel. The new initiative can provide assistance for community energy planning, management, renewable energy and improved technology applications (e.g., small hydro, wind, solar, variable generators), and capacity building, training and tools.

It is not yet known how this program will be applied in the NIA communities, however, there are several First Nations communities that have identified interest in pursuing IPPs or expansions of existing IPPs in their areas, e.g. Tahltan and Heiltsuk areas.”

1.29.1 What is BC Hydro’s understanding of the current status of the federal initiative referred to in the above quote?

RESPONSE:

The above quote refers to the Aboriginal and Northern Community Action Program (ANCAP) which was a \$30.7 million, four year federal program launched in fiscal 2004. The program is now in its final year. The funding for this year was intended to be \$10 million, however it has been reduced to \$6 million, not all of which has been allocated.

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29.0 Reference: F07/F08 RRA, Appendix W (Exhibit B-5-3), p.30

“Looking forward, a new federal government climate change initiative may provide NI communities with opportunities to increase involvement in energy planning and generation. Under this initiative, \$30 million has been earmarked for assisting and supporting the approximately 130 remote, and Aboriginal and northern communities that rely on diesel generation as they work to improve their energy efficiency and adopt alternative energy sources to reduce their dependence on diesel fuel. The new initiative can provide assistance for community energy planning, management, renewable energy and improved technology applications (e.g., small hydro, wind, solar, variable generators), and capacity building, training and tools.

It is not yet known how this program will be applied in the NIA communities, however, there are several First Nations communities that have identified interest in pursuing IPPs or expansions of existing IPPs in their areas, e.g. Tahltan and Heiltsuk areas.”

1.29.2 Please describe BC Hydro’s experience with the use of battery/inverter systems and automated control systems to increase the efficiency of diesel-fueled generation in NIAs. What plans does BC Hydro have to expand the use of such systems?

RESPONSE:

In the past, BC Hydro carried out testing on the battery/inverter systems for station service and found that a well maintained battery program and modern charger system provided a reliable DC backup for the equipment.

BC Hydro has no experience in the NIAs with battery/inverter systems to back up a community’s energy requirements, which would be a much more significant undertaking than to back up BC Hydro equipment. Recently, BC Hydro has been involved in designing and assessing a battery storage system for the non-integrated Pearson - Clean Current - EnCana tidal current demonstration project at Race Rock.

BC Hydro is in the process of investigating pilot projects involving these technologies under the Remote Community Electrification Program.

All NIA stations have automated controls to optimize equipment used to meet system demand and improve fuel efficiency. All newer gensets have automated controls which also increase monitoring (including remote monitoring) and diagnostic capability.

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29.0 Reference: F07/F08 RRA, Appendix W (Exhibit B-5-3), p.30

“Looking forward, a new federal government climate change initiative may provide NI communities with opportunities to increase involvement in energy planning and generation. Under this initiative, \$30 million has been earmarked for assisting and supporting the approximately 130 remote, and Aboriginal and northern communities that rely on diesel generation as they work to improve their energy efficiency and adopt alternative energy sources to reduce their dependence on diesel fuel. The new initiative can provide assistance for community energy planning, management, renewable energy and improved technology applications (e.g., small hydro, wind, solar, variable generators), and capacity building, training and tools.

It is not yet known how this program will be applied in the NIA communities, however, there are several First Nations communities that have identified interest in pursuing IPPs or expansions of existing IPPs in their areas, e.g. Tahltan and Heiltsuk areas.”

- 1.29.3 More generally, what plans does BC Hydro have regarding improvement of energy efficiency and adoption of alternative energy sources to reduce dependence on diesel fuel in NIA communities within the test period?

RESPONSE:

BC Hydro has developed a diesel unit retirement/replacement/reduction strategy for NIA. Within the test period, BC Hydro plans to replace three ageing diesel gensets with modern, fuel efficient and low emission equipment.

BC Hydro NIA had an energy call for Atlin in F2006 and is presently negotiating an Energy Purchase Agreement with an IPP to provide hydro power to Atlin in October 2007.

BC Hydro is also conducting engineering and economic feasibility studies to displace diesel by extending a distribution line from Williams Lake substation to Anahim Lake.

BC Hydro is preparing a business case and working with Sustainable Development Technology Canada (SDTC) and external vendors to share funding to explore executing a pilot hydrogen assisted renewable power (HARP) project in

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Bella Coola. The HARP project seeks to evaluate the use of hydrogen produced from surplus renewable electricity to displace diesel fuel in non-integrated communities.

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30.0 Reference: BC Hydro IEP/LTAP Application, BCUC Project No. 3698419, SCCBC, et al, Information Request #1, Exhibit C-25-3

- 1.30.1 For any and all Information Requests made by SCCBC, et al in the IEP/LTAP proceeding that BC Hydro declined to answer on the ground that the question was more suited for the RRA proceeding, please provide a response(s) in this proceeding.

RESPONSE:

There were no SCCBC IRs on the 2006 IEP and LTAP that BC Hydro declined to answer on the grounds that they were more suited to the F07/F08 RRA.