ERICA M. HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 25675

VIA E-Mail
bchydroregulatorygroup@bchydro.com

September 11, 2008

BC HYDRO – 2008 LTAP
EXHIBIT A-5

Ms. Joanna Sofield
Chief Regulatory Officer
British Columbia Hydro and Power Authority
17th Floor, 333 Dunsmuir Street
Vancouver, B.C. V6B 5R3

Dear Ms. Sofield:

Re: British Columbia Hydro and Power Authority ("BC Hydro")
Project No. 3698514/Order No. G-96-08
2008 Long Term Acquisition Plan ("2008 LTAP")

Enclosed is Commission Information Request No. 2. Please provide 12 hard copies and an electronic copy in your response.

Pursuant to Commission Order No. G-126-08, BC Hydro is to respond to the Information Request by Wednesday, October 15, 2008.

Yours truly,

Original signed by:

Erica M. Hamilton

EC/rt
Enclosure
cc: Registered Intervenors *(BCH-2008 LTAP-RI)*

REQUESTOR NAME: BCUC
INFORMATION REQUEST ROUND NO: 2
TO: BRITISH COLUMBIA HYDRO & POWER AUTHORITY
DATE: September 11, 2008
PROJECT NO: 3698514
APPLICATION NAME: 2008 LTAP Application

172.0 Reference: LTAP Planning Cycle and Update Process
Exhibit B-3, BCUC IR 1.1.1

BC Hydro states that as part of each LTAP it would, among other things, continue to provide a 20-year load forecast, 20-year load/resource balance outlook, and identify action items required over the next ten years.

172.1 Would BC Hydro also expect to consider resource options over a 20-year period, generate portfolios of resource options to meet gaps between load and resources over a 20-year period, and evaluate trade-offs across various planning objectives/criteria over a 20-year period?

173.0 Reference: Alignment with BCUC Decisions
Exhibit B-3, BCUC IR 1.7.1
The Long Term Rate Increase Forecast Report

173.1 The report notes that the rate forecast was not available in time for the 2007 CPR. It notes that the 2007 CPR referenced the 2006 Load Forecast which used rate increase at the rate of inflation as one of the assumptions underlying the load forecasts. The report further notes that given the timing of preparing the 2008 DSM Plan, a January 2008 version of the long term rate increase forecast was used in the estimation of lost revenues associated with that plan.

Given the inconsistent treatment of the impact of real electricity prices among these studies: CPR, 2008 Load Forecast and DSM evaluation methodologies, please comment on the linkages and describe:

173.1.1 The direction and magnitude of change to the 2007 CPR Economic Combined Annual Consumption and Potential Annual Savings if the Long Term Rate Increase Forecast Report (BCUC IR 1.7.1) figures had been used in the 2007 CPR.

173.1.2 The direction and magnitude of change to the Lost Revenues in the 2008 DSM Plan if the Long Term Rate Increase Forecast Report (BCUC IR 1.7.1) figures had been used in the 2008 DSM Plan.

173.1.3 Please provide the issue date of the Long Term Rate Increase Forecast Report (BCUC IR 1.7.1) and the date of the implementation of the next round of EE programs.

174.0 Reference: Alignment with BCUC Decisions
Exhibit B-3, BCUC IR 1.7.1, Attachment 1, page 7 of 9
Real Price Increase

BC Hydro assumes, for the F2019 to F2028 period, rates are to rise at the rate of inflation forecast at 2.1 percent per year.

174.1 Rather than using the assumption of no real price increase, would it be reasonable to assume real price increases in the last ten years at an average of the annual increases in the first ten years of the forecast?

175.0 Reference: Alignment with Energy Plan
Exhibit B-3, BCUC IR 1.143.1
3,000 GWh Surplus

175.1 Please assign a probability that BC Hydro could be in a surplus position of 3,000 GWh by 2020.

175.2 Assume BC Hydro is in surplus of 3,000 GWh from 2020 onwards. What is the likely impact on customer rates given the costs associated with the surplus and the likely revenues from resale?

176.0 Reference: Alignment with UCA Amendments
Exhibit B-3, JIESC IR 1.4.5; UCA s. 44.1(4) (c)
Management of DSM Risks

"BC Hydro is aware that historical sales used in forecast regression models are influenced by past rate changes and DSM programs. As stated at page 6-9 of Exhibit B-1-1. "…., the tracking of how BC Hydro's load is responding to DSM programs will need to be closely monitored. A key issue will be the methodology used for integrating historical loads with increasing levels of DSM savings into BC Hydro's load forecasting research and analysis."

176.1 For each year, between 2006/2007 and 2019/2020, please provide a summary table showing the Reference Case demand increase (GWh) for BC Hydro Total Sales and by Residential, Commercial, Industrial Sector before DSM and with rate impacts, and 50 percent of Total demand increase.

176.1.1 In tabular format, please show for each year the GWh/year savings under Option A and Option B under mid, low and high cases.

176.1.2 Please show the energy gap for each year and the percentage of energy gap that could be met under DSM Option A and Option B under mid, low and high cases.

176.2 Please repeat the above IR for the High Load Forecast Case and the Low Load Forecast Case.

176.3 When addressing the integration of historical loads with DSM savings, please describe if BC Hydro is planning to address the integration by customer sector to account for the difference in persistence of DSM programs among sectors.

176.4 Please provide references to the DSM savings in the Energy Requirements and System Peak tables in the Response to JIESC IR 1.4.5.

177.0 Reference: Natural Gas Price Forecast
Exhibit B-1, p. 4-16
Exhibit B-3, BCUC IR 1.74.2

177.1 BC Hydro states that the inflection point in 2016 for the mid forecast is due to the impact of additional LNG supplies plus the arrival of Arctic gas. The mid forecast curve in Figure 4-2 shows a downward inflection at 2014 and an upward inflection at 2016. Please identify when the impacts of more LNG and Arctic gas are predicted to occur, and provide a more fulsome explanation of the shape of the mid forecast curve.

177.2 To place the gas price forecasts in historical context and provide a comparison to other forecasts, please provide a form of Figure 4-2 that includes:

- A weighted average curve for the current LTAP low, mid and high forecasts.
- The most recent available Energy Information Administration ("EIA") Reference Case forecast.
- The EIA AEO 2008 Early Release forecast (please explain the relationship between the EIA AEO and EIA Reference Case forecasts).
- The most recent Confer Consulting Long Run Marginal Cost forecast.

The use of color to distinguish the curves would be helpful.

177.3 Please discuss why BC Hydro has adopted the Global Energy forecasts for the 2008 LTAP, and if possible, include a comparison of the accuracy of past Global Energy and other forecast alternatives to actual realized gas prices.

178.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix 1, pp. 18, 20-25, 31
Exhibit B-3, BCUC IR 1.75.1

178.1 Further to the description of the Low Gas Price case, please discuss how the assumptions that define the Low Gas Price case compare to conditions in BC Hydro's service area under the Province's current Energy Policy.

178.2 If one assumes that the Province's Energy Policy conditions apply across the WECC region, would the probability of the Low Forecast be as low as 3 percent? Please explain the reasons for the response. If the probability would not be 3 percent, what would it be expected to be?

179.0 Reference: Market Assessment for Clean or Renewable Energy
Exhibit B-3, BCUC IR 1.92.2

BC Hydro states: "The REC sales in any given year are calculated by multiplying the net positive GWh of electricity exported by the corresponding REC price forecast shown in Figure 4-7 in the 2008 LTAP (Exhibit B-1). Three REC sales values are obtained by using a low, mid, and high REC price scenario." BC Hydro provides examples of REC sales based on the mid gap, high gas, mid GHG portfolio and the high gap, high gas/GHG portfolio.

179.1 BC Hydro's methodology seems to treat the value of RECs as completely independent of GHG regulation. Please confirm. Why would the value of RECs not relate in part to GHG regulation/costs, considering one of the main drivers for purchasing RECs is to reduce GHG emissions? If GHG is taxed (effectively internalizing the cost of GHG emissions from conventional sources) and general electricity prices rise, why would the value of RECs not decline to a level reflecting any residual, non-internalized environmental or social benefits? Is BC Hydro not potentially double counting the value of exports by including both REC benefits and higher market electricity prices under a given scenario with GHG regulation?

180.0 Reference: Load Forecast Methodologies
Exhibit B-3, IPPBC IR 1.4.2
Exhibit B-1-1 Appendix D, p. 49 of 103

180.1 For each category of industrial customer in Table 8.1, please provide all adjustments to the forecast by year including specific adjustments such as for the three mines, and generic adjustments, such as that provided in response to IPPBC IR 1.4.2.

180.2 Please explain why it is necessary to make generic adjustments when the relationship between sales and GDP regressions is intended to capture non-specific load growth.

181.0 Reference: Load Forecast Methodologies
Exhibit B-3, IPPBC IR 1.5.1

181.1 By using a regression equation based on historical data in load forecasting where load was influenced by DSM programs, is BC Hydro implicitly assuming that the same level of DSM effort will persist in the future?

182.0 Reference: Load Forecast Methodology
Exhibit B-3, BCUC IR 1.26.1

182.1 Please confirm that the temperature used for the peak normalization is the same as is used for peak forecasting.

183.0 Reference: Existing and Committed Resources
Exhibit B-3, BCUC IR 1.31.1

183.1 BC Hydro provides a summary of the derivation of SOP volumes. Please also provide: (a) formal applications received under the SOP since it was implemented on April 11, 2008; (b) the number of applications and for what volume; and (c) indications from other proponents regarding their intention to apply?

184.0 Reference: Existing and Committed Resources
Exhibit B-3, BCUC IR 1.28.1

BC Hydro states: "The financial benefit of deferring 5L83 is relatively small (e.g. approximately $7 million in savings per year of deferral, excluding consideration of incremental Burrard out-of-merit RMR dispatch costs, additional U.S. import costs and the increased risk of widespread customer outages)."

184.1 Please provide the source, derivation and assumptions for BC Hydro's estimate of the benefits of deferring 5L83 to $7 million per year.

185.0 Reference: SD 10 Impact on Resource Requirements
Exhibit B-3, BCUC IR 1.33.1

185.1 Is the net effect of (a) eliminating the reliance on 2,500 GWh non-firm/market allowance in 2016 and (b) inclusion of only the FELCC of domestic IPPs to reduce the firm energy contribution of committed resources by 400 GWh (54,800- 54,400) in F2012 and 2,900 GWh (54,200-51,300) in F2020?

185.2 BC Hydro has relied on the non-firm/market allowance for many years and has also indicated that the allowance can be met with domestic IPP non-firm energy OR market purchases. Please discuss in greater detail why BC Hydro now considers this practice unacceptable in meeting its planning, particularly if the criterion is limited to non-firm energy from domestic IPPs.

185.3 Please provide an estimate of total additional non-firm energy available to BC Hydro from (a) committed and (b) planned resources under 5^{th} percentile, 10^{th} percentile, 50^{th} percentile, 90^{th} percentile, and 95^{th} percentile water conditions (and not included in the firm energy balances in the table that accompanies this IR response) in F2012 and F2020.

186.0 Reference: Load/Resource Balance
Exhibit B-3, BCUC IR 1.57.1

BC Hydro provides a lengthy explanation of how it considered intermittent resources in the portfolio analysis. However, BC Hydro also states: "BC Hydro does not vary the assumption of FELCC and ELCC contribution from any specific resource, including wind resources, as a function of portfolio composition in the portfolio analysis."

186.1 This statement suggests there is no recognition of the possible value of aggregation of intermittent resources. Please reconcile this situation with Policy Action # 25 in the BC Energy Plan which states: "Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources."

187.0 Reference: Load/Resource Balance
Exhibit B-3, BCUC IR 1.36.1 AND 1.36.2

In response to BCUC IR 1.36.1, BC Hydro states: "The 3,000 GWh insurance requirement by 2026 has been reflected in the 2008 LTAP Base Resource Plan which is shown in Table 6-15 on page 6-54 of Exhibit B-1. BC Hydro is forecasting a 3,600 GWh surplus, after 2008 LTAP actions and future resources are included, in F2026."

In response to BCUC IR 1.36.2, BC Hydro states: "With respect to BC Hydro's interpretation of section 3(e) of SD 10, which directs the BCUC, in regulating BC Hydro, to use the criterion that BC Hydro is to exceed, "as soon as practicable *but no later than 2026*, the electricity supply obligations by at least 3,000 GWh/year and by the capacity required to integrate that energy in the most cost-effective manner …", please refer to the response to BCUC IR 1.143.1. The 3,000 GWh /year insurance established through SD 10 was included in the portfolio analysis as a requirement to be achieved by 2026, and was ramped up as an additional requirement of 1,000 GWh/year, 2,000 GWh/year and 3,000 GWh/year over years 2024, 2025 and 2026 respectively."

Table 6-15 shows a firm surplus of 2,600 GWh in F2016 and 1,600 GWh in F2017 under the mid-load forecast. The surplus in F2016 and F2017 would have been even higher without the removal of the non-firm allowance commencing in 2016.

187.1 Please reconcile the response to BCUC IR 1.36.2 with Table 6-15, which shows surpluses commencing as early as the beginning of the planning period.

187.2 Please discuss why BC Hydro considers its proposed surpluses and/or proposed ramping strategy "the most cost-effective manner" of meeting the insurance requirements in SD10.

188.0 Reference: Existing and Committed Resources
Exhibit B-3, IPPBC IR 1.7.2
Burrard

188.1 In order to understand the impact on overall costs please provide the following information: by keeping Burrard in a state of being "capable", but actually relying on market purchases, what will be the capital and operating cost for Burrard for each year until 2020, and what are the associated avoided running costs (including carbon tax) and market purchase costs in each year.

189.0 Reference: IPP Supply and Attrition Rates of Past Calls
Exhibit B-3, JIESC IR 1.3.1

189.1 Please recalculate the table provided with the first five rows omitted. Please describe the circumstances of each of these processes that resulted in the awarded amount exactly equaling the post-COD amount.

190.0 Reference: Resource Options (General)
Exhibit B-3, BCUC IR 1.154.1
System Optimization Model

190.1 Why is the objective function minimizing the NPV of the revenue requirement as opposed to the DCF? Is this consistent with Commission directives in the previous LTAP?

190.2 As requested in the IR, please provide the objective function and constraints.

191.0 Reference: Financial Assumptions
Exhibit B-3, BCUC 1.61.1 and 1.61.2

BC Hydro refers to BCUC 1.60.2 in its responses to BCUC IR 1.61.1 and 1.61.2. However, the response to BCUC IR 1.60.2 does not specifically address the effects of OIC 27 or 28 on the appropriate portions of debt and equity in the calculation of BC Hydro's weighted average cost of capital.

191.1 Please discuss if and how the OIC No. 27 and 28 alter the cost of capital and discount rate used in the 2006 IEP/LTAP analysis.

192.0 Reference: DSM ROU
Exhibit B-3 BCUC IR 1.43.2; IR 1.67.1, Attachment 2, pp. 41 to 44 & 80 of 132

"LEED is not expected to be mandated within the B.C. Building code and thus not included within the codes and standards reflected in DSM Option A or Option B. Net electricity savings from LEED buildings that are expected to participate in DSM programs are included in the DSM Plan electricity savings under programs and deducted from the load forecast before DSM to calculate the load forecast after DSM."

192.1 Section 44.1(4)(c) of the UCA states that "demand-side measures taken by the government of British Columbia or of Canada or a local authority" would be included in BC Hydro's long-term resource plan. Does BC Hydro consider demand side measures undertaken by municipalities to fall under this section? If no, why not? If yes, please explain how BC Hydro monitors and evaluates municipalities' demand side measures (e.g., property tax exemption, zoning approval, contractual agreements with developers/builders, etc.).

192.1.1 The Climate Action Plan at p. 43 of 132 describes the BC Local Government Grants Program for projects supporting community energy planning and reducing greenhouse gas emissions. Are any of the projects counted as demand side measures? If so please describe the estimated savings. If no, please explain why not.

192.2 The Response to IR 1.43.2 implies that certain net electricity savings from LEED buildings are expected to be included in the DSM Plan. Please describe which DSM program would the net electricity savings from LEED buildings fall under.

192.3 Page 44 of 132 of the Climate Action Plan states that "effective immediately, all now provincially owned or leased facilities must be built to a minimum of" LEED Gold or equivalent criteria. Does this mandatory standard for certain buildings in the province make LEED a subset of "equipment and buildings" which will impact the resulting electricity savings? (X-reference: Exhibit B-1, Appendix K, page 27 of 213 on Codes and Standards coverage)

192.3.1 If not, please explain why not in light of the Climate Action Plan. If so, please amend the Response to IR 1.43.2 and provide the estimated DSM savings that would contribute to the reduction in demand increase by 50 percent by 2020 as stipulated in Section 44.1(4)(c) in the *UCA*.

192.4 The Climate Action Plan at page 80 of 132 states that a B.C. Green Building code will be developed and that the energy and water efficiency revisions will go into effect September 2008. Is this Action included in BC Hydro's DSM Option A in the Portfolio Analysis?

193.0 Reference: DSM ROU
Exhibit B-3, BCUC IR 1.49.3

In its response, BC Hydro states: "Program offers are designed to cause customers to undertake cost-effective DSM measures that are not being pursued. In determining a program offer, including incentive levels, BC Hydro takes into account the barriers to cost-effective DSM measures, electricity prices and any other incentive offered to the customer, such as net metering or offers from partner programs. This approach was used in determining the appropriate program offer for the Load Displacement programs in the DSM Plan."

At page 155 of Appendix K, Sub-Appendix F (Exhibit B-1-1), BC Hydro states in its description of residential load displacement programs: "The program objective is to prime the solar market in B.C. and assist in creating the infrastructure that will be required to rapidly move forward with the installation of solar technologies as they become cost effective in B.C." BC Hydro also notes: "Neither solar PV nor solar thermal technology are presently cost-effective for consumers in B.C. due to high capital costs and low electricity rates. Customer decisions to install these technologies today go beyond economics alone."

193.1 Please confirm this program supports measures that are currently not considered cost-effective either from a customer perspective or from a utility perspective.

193.2 Please provide evidence concerning when the target technologies (solar thermal and solar PV) could reasonably become cost-effective in B.C. (as compared to other alternative energy solutions) and how this program could be expected to accelerate or otherwise improve the cost-effectiveness of these technologies.

194.0 Reference: DSM ROU
Exhibit B-3, BCUC IR 1.49.4

BC Hydro states: "It is uncertain what proportion of cost-effective customer-based generation would not participate in the SOP. However, given the barriers to customer-based generation, it is reasonable to believe that some cost-effective projects will not be attracted to the SOP."

194.1 Please clarify how much potential overlap there could be in project eligibility for the two programs (e.g., size thresholds, technology type, etc.).

194.2 Please describe the specific mechanisms/methods BC Hydro will use to identify residential, commercial and industrial customer-based generation projects eligible for incentives under its load displacement programs and how it will prioritize projects if the amount of incentives they require exceeds budgeted amounts.

194.3 Please describe how BC Hydro will evaluate whether to provide an incentive and the specific measures BC Hydro will use to minimize the potential for free riders (i.e., projects that would have proceeded under the SOP without an incentive but are successful in getting an incentive under the load displacement program.)

195.0 Reference: DSM ROU
Exhibit B-3, BCUC IR 1.50.1

195.1 Please confirm the All Ratepayer Costs F2009-F2028 ($ million) value in the table filed as part of this response is a present value of expenditures to F2028. Please clarify what discount rate is used in calculating the All Ratepayer Costs. Please clarify also whether the expenditures used in this calculation are in real or nominal dollars.

195.2 Please provide a similar table but showing the present value of all planned energy savings between F2009 and F2028 (using the same discount rate as in the All Ratepayer Costs) and estimating the percentage savings attributable to Load Displacement programs on a present value basis.

196.0 Reference: DSM ROU
Exhibit B-3, BCUC IR 1.50.2

BC Hydro states: "The more aggressive residential rate structure in Option B would result in more of the participants in the Residential Behaviour Program taking action because of the rate structure alone without the aid of the program. To avoid double counting of energy savings due to the rate structure and the program together, the assumed level of free ridership in the program is higher in Option B than Option A, which results in lower net energy savings for the program. This change does not impact program costs."

196.1 Does this not suggest that spending on residential behavioural programs should be reduced under the more aggressive rate structures associated with Option B, as the programs offer fewer benefits?

197.0 Reference: DSM ROU
Exhibit B-3, BCUC IR 1.50.3

197.1 Please summarize the methodology and assumptions for calculating the All Ratepayer Levelized Costs, including discount rate, analysis period, etc. Provide a sample calculation for one program.

198.0 Reference: DSM ROU
Exhibit B-3, BCUC IR 1.50.3
Composition of Options A and B

198.1 Please explain the rationale behind the composition of Options A and B. For instance, should Option B not contain more of the low TRC cost programs such as lighting and renovation rebate instead of more high cost programs such as load displacement and sustainable community?

199.0 Reference: DSM Plan and Action Item
Exhibit B-1-4, Appendix K 2007 CPR Summary Report

At page 154 of the 2006 IEP/LTAP decision, as corrected by letter dated June 11, 2007:

> "The Commission Panel further directs BC Hydro to rely on the report for assumptions regarding retail prices in each of the CPR, the load forecast, and DSM evaluation methodologies. Furthermore, the report should identify and explain linkages, if any, of the impact of real electricity prices in the CPR, the load forecast and BC Hydro's DSM evaluation methodologies. The report must demonstrate the consistent treatment in each, and address the concerns raised above. The Commission Panel believes such a report would be desirable at the time of the 2007 CPR, but notes that this was not an item in the terms of reference. In any event, the Commission will require such a report in advance of the implementation phase of the next round of EE programs."

199.1 The forecast provided in the report in BCUC IR 1.7.1 was not used in the CPR and the forecast of real prices in the CPR was zero percent annually which was consistent with the 2006 Annual Load Forecast. Are the CPR models currently capable of using a non-zero forecast of BC Hydro rate increases as an input to calculating economic potential?

199.2 Please explain if price levels and price elasticity have a role in the CPR models.

199.3 Using the CPR models please recalculate the Economic Combined Annual Consumption and Potential Annual Savings in Exhibit 2.1 page 18 of 58 of the CPR Summary Report, using the 20 year financial forecast as an input.

199.4 The 2007 Conservation Potential Review constitutes a Summary Report and over ten other reports. Please attach hard copes of pages 57 through 68 of the 2007 CPR The Potential for Energy Savings through Technology Adoption 2006 to 2026, Residential Sector.

199.4.1 Sections 4.3 and 4.4 of the abovementioned report define "natural" changes as naturally occurring retrofit activities. Please provide a detail definition. For example, does "natural changes" refers solely to changes in energy use due to stock rollover as appliances reach the end of their physical life and must be replaced by newer and likely more efficient appliances?

199.4.2 Was a financial forecast of BC Hydro's rates specifically used in determining natural conservation for:

199.4.2.1 Heating and cooling?

199.4.2.2 Appliances?

199.4.3 Page 58 of the abovementioned report states that heating and cooling retrofits experience a net per unit space heat reduction of 3 percent and 2 percent for pre and post 1976 units respectively. Please compare these figures with the savings BC Hydro estimated for retrofits during the RIB proceeding (Exhibit B-7, BCUC IR 2.59.2 and IR 2.73.1).

199.4.4 Page 61 of the abovementioned report states that for existing and retrofitted dwellings, the domestic hot water (DHW) UEC is assumed to decrease by 0.2 percent per year based on data from NRCan. Should this assumption on DHW UEC vary with the price of electricity? Please explain your answer.

199.4.5 Page 67 of the abovementioned report states that "The only change in fuel shares assumed in the study period is the relative growth in electrically heated versus non-electrically heated dwellings, as discussed in Section 4.6 above. No changes are assumed in their fuel shares for any other end uses." Should this assumption vary with BC Hydro forecast retail electricity prices?

199.5 Please attach hard copies of the relevant sections of "Potential for Electricity Savings through Technology Adoption Reports" that pertain to natural conservation, saturation trends, stock growth and fuel shares for the Commercial and Industrial Sectors.

199.5.1 Please explain if natural conservation and fuel shares are impacted by a forecast of BC Hydro's retail rates for the Industrial and Commercial sectors.

200.0 Reference: DSM Plan and Action Item
Exhibit B-1-4, Appendix K, 2007 CPR Summary Report, p. 14 of 58

It is stated that: "In the case of energy-efficiency upgrades, the consultants then used a formula to produce a value for cost per year per kilowatt-hour of saved electric energy, referred to as the Cost of Conserved Energy (CCE)."

200.1 Please provide the formula used and an example of the calculation used for an envelope upgrade or other such project as BC Hydro feels would be expository.

201.0 Reference: DSM Plan and Action Item
Exhibit B-1-4, Appendix K, 2007 CPR Summary Report, p. 15 of 58

Cost effective for the purposes of the study means a cost of conserved energy (CCE) of 13 cents per kWh or less.

201.1 In what unit is the 13 cents expressed? E.g., real, nominal, levelized?

201.2 It is stated that the 13 cent screen is increase by 50 percent above the reference price of 8.8 cents based on the results of the 2006 Call in order to "capture potential future opportunities above current costs". Please explain in detail the meaning of the quoted phrase. Please provide the empirical basis for the 50 percent figure.

201.3 Please re-estimate the Economic Combined Annual Consumption and Potential Annual Savings (Exhibit 2.1 at page 18 of 58 of the Summary), using energy economic screen of 8.8¢ and 8.27¢/kWh.

201.4 The capacity screen is 50 percent above a value of $115/kW/yr. Please provide the derivation of the $115.

201.5 It is stated that achievable potential recognizes that it is difficult to induce customers to purchase and install all the technologies that are economic (less than or equal to 13 cents). Since the TRC is not impacted by the level of incentives which are merely transfer payments, shouldn't the Upper Achievable potential be calculated assuming that incentives for each program are paid up the point the TRC is 1 which in many cases will result in participating customers being paid the full capital costs of the upgrade, which in turn would induce significant added customer participation and achieve the goal of achieving all cost-effective DSM?

202.0 Reference: DSM Plan and Action Item
Exhibit B-1-4, Appendix K, 2007 CPR Summary Report, p. 24 of 58

"For the Residential sector, the consultants developed detailed profiles of new buildings for each type of dwelling. They estimated the growth in building stock and estimated the amount of electricity used by both the existing building stock and the projected new buildings and appliances. In doing so, they incorporated the energy savings that would be expected to occur naturally due to improvements to thermal characteristics of existing homes and appliances over the study period. As with the Base Year calibration, the consultants' projection closely matches BC Hydro's own December 2006 forecast of future electricity requirements."

202.1 Please provide a table showing the annual values for: (a) natural energy savings; (b) the consultants' projections of load; (c) BC Hydro's December 2006 forecast of future electricity requirements, with references; and (d) BC Hydro's forecast of the amount of natural conservation.

202.2 Please provide the same table for the commercial sector.

202.3 Please provide the same table for the industrial sector.

202.4 Please provide the same table for total sales.

203.0 Reference: DSM Plan and Action Item
Exhibit B-1-4, Appendix K, 2007 CPR Summary Report, p. 37 of 58

203.1 Does BC Hydro's industrial load forecast explicitly account for industrial self-generation? If so, how and in what amounts? Please provide references to the 2008 Load Forecast.

204.0 Reference: DSM Plan and Action Item
Exhibit B-1-4, Appendix K, 2007 CPR Summary Report, p. 44 of 58

204.1 Please list the 25 and 15 behaviors in the respective Residential and Commercial sectors that affect the major end uses.

205.0 Reference: DSM Plan and Action Item
Exhibit B-1-4, Appendix K, 2007 CPR Summary Report, p. 49 of 58

205.1 Please define "lifestyle measures" and list the 21 lifestyle measures that could reduce electricity end use.

206.0 Reference: DSM Plan and Action Item
Exhibit B-1-4, Appendix K, 2007 CPR Summary Report, pp. 53-55

206.1 In reference to fuel switching it is stated that the 50 percent adder is not included in the Economic screen value because the methodologies are different. Please explain this in more detail, and in particular, when considering the perspective of society, why shouldn't the 50 percent adder be included?

206.2 Please calculate Exhibits 9.1 and 9.2 using a value of 13 cents per kWh.

206.3 Why isn't it possible the pay an incentive for fuel switching, must as other DSM programs pay an incentive, in order that the potential savings from fuel switching are not zero? If a significant incentive were paid, what would be the likely impact on RIM?

207.0 Reference: DSM Plan and Action Item
Exhibit B-1-4, Appendix K, 2007 CPR Summary Report, pp. 57, 58 of 58

207.1 Please describe BC Hydro's position with respect to the 14 recommendations.

207.2 Recommendation 10 of the Summary Report states:

"BC Hydro should consider undertaking more study to examine the conservation implications of implementing measures on a full-cost basis. As shown in the CPR, energy conservation appears to be achieved more quickly when measures are implemented on a full-cost basis. However, it is not clear that this benefit outweighs the increased level of waste resulting from replacing equipment long before the end of its useful life."

The statement implies that increasing incentive levels will increase program participation and energy savings. Please discuss.

207.2.1 Since it appears that there is a link between incentive levels and savings potential, were the members of the study group aware of the incentive levels for individual programs when assessing the upper and lower achievable potential? If not, please explain how they made a reasoned evaluation of the upper and lower achievable amounts?

207.2.2 How does the assessment of BC Hydro's DSM programs take into account the increased level of waste from replacing equipment before the end of its useful life? How is this waste reflected in the TRC or RIM measures?

208.0 Reference: DSM Plan and Action Item
Exhibit B-3, BCUC IR 1.167.1
Voltage Optimization

208.1 Please provide summaries of all reports regarding BC Hydro's implementation of voltage optimization on a trial basis.

208.2 Please provide all benefit costs analyses relevant to BC Hydro directly, or other utilities of which BC Hydro is aware.

208.3 Please explain the benefits of voltage optimization for (1) electrically heated dwellings, (2) indoor lighting loads, (3) outdoor lighting loads and (4) motor loads.

208.4 Has BC Hydro taken into account cross-over effects such as increased heating loads (e.g., less waste heat from indoor lighting)when calculating TRC or other cost-benefit analyses?

209.0 Reference: DSM Plan and Action Item
Exhibit B-3, BCUC IR 1.170.1
DSM Evaluation

209.1 Please describe the "estimation process" that separately quantifies total DSM savings and savings from DSM initiatives other than rates. How does this process quantify energy use reductions resulting only from real general (not rate structure related) increases in the price of electricity?

210.0 Reference: DSM Plan and LTAP Action Item
Exhibit B-3, BCUC IR 1.115.2, BCOAPO IR 3.69(b)
Exhibit B-1, Chapter 1, Introduction and Context, Section 1.1.2 Orders Sought, pp. 1-2 and 1-3
Appendix K, pp. 101-114, BC Hydro F09-F10 RRA, Exhibit B-10, Evidentiary Update

In the response to BCUC IR 1.115.2, BC Hydro referred to BCOAPO IR 3.69(b) from the F09/F10 RRA proceeding and noted that the total DSM amortization in the RRA Evidentiary Update was correct but the split between existing assets and additions was incorrect. This change resulted in the Amortization on Existing Assets to become ($41.6 million) in F09 and ($41.3 million) in F10. The Amortization on Additions was also changed in accordance with the response to BCOAPO IR 3.69(b) to have zero amortization for F09 and ($11.2 million) for F10.

BCUC IR 1.115.2 requested the completion of a table where the DSM amortization of the opening balance is over ten years while the amortization of the F09 and F10 additions are alternatively over five to ten years.

BC Hydro completed the requested table with the Amortization on Existing for F09 and F10 shown as requested and with the Amortization on Additions for F10 increasing to ($12.5 million) based on a 9 year amortization of ($11.2 million*10/9) and by a similar manner as the amortization period shortened to 5 to 8 years.

In the second paragraph of the response to BCUC IR 1.115.2, BC Hydro states that "it is assumed that the F09 opening balance of the DSM regulatory account is amortized over periods of five through nine years going forward..." Please explain the relevance of that statement when the table has the F09 Amortization on Existing fixed at ($41.6 million) for each amortization period of 5 to 10 years.

211.0 Reference: Mica Unit 5 and 6 LTAP Action Items
Exhibit B-3, BCUC IR 1.134.1

211.1 Please explain in detail the scope and nature of an expenditure Determination application, including the specific order that will be sought with respect to Mica Unit 5 and Unit 6.

212.0 Reference: Mica Unit 5 and 6 LTAP Action Items
Exhibit B-3 BCUC IR 1.134.1

212.1 Please provide schedules showing the current best estimates as to timing and annual costs for both the entire Mica 5 and entire Mica 6 projects.

212.2 Please explain, in relation to these schedules, the urgency in advancing the request for Definition phase expenditures and closing the evidentiary process (Procedural Conference Transcript Volume 2 page 79 lines 2 to 7).

212.3 Given that BC Hydro will only be filing an "expenditure Determination application", if the 2008 LTAP is approved and the Mica Definition Phase expenditures are also approved, will there be a detailed public examination of the timing, the need for, and costs related to Mica?

213.0 Reference: Burrard Technical Analysis
Exhibit B-3, JIESC 1.8.8
Burrard as RMR

213.1 Assuming ILM were delayed until the end of F2020, in each year how many hours would it be necessary to operate Burrard to support the transmission system, and for each of those hours what would the committed capacity be?

213.2 The last paragraph of the response to BCUC IR 1.28.1 states "The results are summarized in Figure 2 below and are compared with the existing ILM network N-1 rating of 5000 MW. It should be noted that 5L83 cannot be deferred for any of the cases shown below without committing Burrard capacity as RMR and incurring the associated incremental operating costs." Please provide the referenced incremental operating costs in nominal, real, and real NPV dollars until the end of the forecast and provide the calculation.

213.2.1 Please explain in detail the annual deferral benefit savings of $7 million and the additional US import costs. Please show them annually and as a real NPV amount.

213.2.2 Please provide BC Hydro's load duration curve in electronic spreadsheet form and graphically.

213.2.2.1 Please calculate the number of hours that load is (1) within 150 MW of the system peak (2) within 300 MW of the system peak (3) within 450 hours of the system peak (4) within 600 hours of the system peak (5) within 750 hours of the system peak and (6) within 900 MW of the system peak.

213.3 Please provide some discussion regarding the exact nature of the other considerations (e.g., Burrard out-of-merit dispatch, import costs, etc.) and their potential costs. When highlighting the potential costs of these other considerations, please also discuss the expected frequency with which these would be incurred in any given year.

213.4 Please explain in detail why the DGC of BGS is committed as RMR only until ILM is reinforced and not thereafter and the consequences of using BGS as RMR until 2020. Has BC Hydro or BCTC prepared any reports or benefit/cost analyses of the impacts of longer term use of at least some of the Burrard units as RMR? If yes please provide the documents.

214.0 Reference: Burrard Generating Station Portfolio Analysis
Exhibit B-3, BCUC IR 1.991

BC Hydro describes its communications with Metro Vancouver staff and with the City of Port Moody and attaches a newspaper article which describes the views of a Metro Vancouver official.

214.1 Please provide documentation of the opinions on Burrard by the City of Port Moody officials and include in the documentation the City's June 24, 2008 consideration of the Burrard Thermal Liaison Committee's recommendation.

215.0 Reference: Burrard Generating Station Portfolio Analysis
Exhibit B-3-2, IPPBC 1.7.1

215.1 Please explain how BC hydro's "social license" for Burrard would be affected if it planned to rely on 4,000 GWh/year rather than 3,000 GWh/year from Burrard.

215.2 BC Hydro states that it is "operationally feasible" to plan to rely on Burrard for 3,000 GWh/year. Is it also operationally feasible to rely on it for 4,000 GWh/year? If not, please explain.

216.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-1-7, pp. 4-6

216.1 Further to Table 3, please explain why the effluent discharge for the FNG case is so much higher than for the FNGU cases.

216.2 Please identify any material problems that are caused by raw water usage or effluent discharge for FNG, in terms of regulatory permits, cost or operations.

216.3 Please expand Table 5 to include FNGU Case 3.2 without duct firing. Will this be the normal operating mode?

217.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-1-7, pp. 13, 14, 16

217.1 With reference to Figures 1 and 2, what is the "largest single contingency assumed to be unavailable" (N-1) in Figure 2?

217.2 Please explain why the N-1 scenario for Figure 2 does not reduce available supply, rather than increase load.

217.3 Please provide a figure for the N-1 scenario that is based on forecast load and the supply that would be available under N-1 conditions.

218.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-1-7, p. 19

218.1 BC Hydro states that approximately 35 MW of additional capacity will be available from TMR, but that this is of no additional value for providing firm service. Please explain if the need to run TMR generation on the Alberta side in some way limits the firm capacity that AESO can or will provide to BC Hydro, and how any such impediment could be removed.

218.2 BC Hydro further states that "the interconnection is setting the N-1 condition (no room for firm capacity over the size of FNGU)". As it is not obvious why the size of FNGU is directly related to the capacity of the interconnect, please explain the statement.

218.3 What is the current physical capacity of the interconnect with the Alberta system? Could this interconnect be expanded by a small amount at modest cost? What would be the amount of the small increase, and what would it cost?

218.4 Please discuss any contractual, regulatory or other similar limits on the capacity of the interconnect.

219.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-1-7, pp. 5, 17, 20, 23

219.1 Please confirm that Figures 7 and 9 indicate that FNGU Case 2 and 3.2 are approximately equivalent with respect to meeting load under N-1 conditions through 2011.

219.2 Please confirm that Figures 7 and 9 indicate that FNGU Case 2 and 3.2 are approximately equivalent with respect to meeting load under N-1 conditions after about 2015.

219.3 Please confirm that FNGU Case 3.2 Net capacity of 75.5 MW under winter peak conditions is capable of meeting the New Inquiries & Reference Forecast until 2015.

219.4 Please explain BC Hydro's contingency plan for meeting the additional load after 2015.

219.5 Please outline the schedule for developing the plans and constructing the facilities to provide the supplies in excess of 75.5 MW.

220.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-1-1, pp .6-49, 6-50
Exhibit B-1-7, p. 28

220.1 BC Hydro states "The only portfolio of resources that BC Hydro is aware of that can provide this requirement on a firm basis is the combination of the AESO Option A1 transmission upgrade and the FNGU Case 3.2". Please clarify if BC Hydro seeks Commission approval of FNGU Case 3.2 in this LTAP filing.

220.2 Considering the relatively small differences in load serving ability of Case 2 and Case 3.2 and the inability of Case 3.2 to meet potential additional load growth after about 2015, please explain why the relative costs of the options were not identified as factors to be taken into consideration when comparing the various options?

220.3 Considering that Figure 9 indicates that FNGU Case 3.2 will not be able to supply the objective Low scenario load under N-1 conditions until 2012, please explain why a further year or two of delay should be considered serious enough to rule out other alternatives.

220.4 For FNGU: Case 2, please outline the construction schedule, and identify the period(s) when no power would be available from FNG.

220.5 Please repeat the previous question for FNGU: Case 3.2.

221.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-1-7, p. 5

221.1 Please provide estimates of the incremental capital costs for each of FNG, FNGU: Case 2 and FNGU: Case 3.2, and include the level of accuracy of each estimate.

221.2 What are the annual depreciation amount and the current net book value of FNG?

221.3 Please provide estimates of the annual capital charges for each of FNG, FNGU: Case 2 and FNGU: Case 3.2.

221.4 Please provide estimates of the annual OM&A expenses for FNG, FNGU: Case 2 and FNGU: Case 3.2.

221.5 Please compare the annual costs to ratepayers of FNG, FNGU: Case 2 and FNGU: Case 3.2.

222.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-1-7; pp. 5, 24-27

222.1 As FNG has a capacity of 47.8 MW, please confirm that FNG plus a CCGT with a capacity of 27.7 MW (75.5 – 47.8) would provide the same amount of capacity as FNGU: Case 3.2.

222.2 Further to page 25, please provide an estimate of the capital cost and in-service date of a new greenfield CCGT with a capacity of approximately 27.7 MW.

222.3 Please compare the annual costs to ratepayers of the alternative of retaining FNG and the construction of a smaller new CCGT.

222.4 Please discuss whether the difference in in-service dates between such a smaller new CCGT and FNGU: Case 3.2 would be material in the circumstances.

223.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-1-7; pp. 5, 24-27

223.1 Further to Section 2.10.3.2, please provide descriptions of the six bioenergy projects, including the MW of capacity that would be expected to be available from each.

223.2 Assuming FNG remains in service and AESO Option A1 upgrade goes ahead, please discuss the ability of the bioenergy projects to provide a sufficient amount of capacity that has adequate reliability and dispatchability.

223.3 What does BC Hydro expect would be the cost to ratepayers of power from the bioenergy projects? Please explain the basis of the estimate.

223.4 Assuming the bioenergy projects are in effect base loaded, what would be the expected annual cost of power from these projects?

223.5 What would be the expected net annual savings when the reduced fuel consumption at FNG and the reduced power purchases from the AESO are taken into consideration?

223.6 Please expand Table 6 on page 6 to include the case where the bioenergy projects are base loaded, with FNG treated as dispatchable generation.

223.7 Please provide an overall assessment of the costs and benefits of the alternatives of retaining FNG and obtaining the additional power from either a smaller new CCGT or from bioenergy projects, compared to FNGU: Cases 2 and 3.2.

224.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-1-7, p. 18
FNGU Alberta Transmission Option

224.1 Does BC Hydro have any preliminary indication, or has it approached the AESO for an indication, of the cost of arranging additional capacity supply from the Northwest Alberta Area Upgrade project?

225.0 Reference: Fort Nelson Generating Station Upgrade
Exhibit B-3, EnCana IR 1.9.1
FNGU Development Load Times

225.1 The IR requested lead times required to develop oil and gas production such as that reflected in the three load growth scenarios. BC Hydro replied that since the information was project specific it was not able to provide the requested information. Has BC Hydro approached the proponents of the three projects in order to understand lead time? Since, if the lead time for the projects were in excess of the lead times for FNGU, BC Hydro would be able to perform the upgrades after the projects were committed to by the proponents, and thereby not risk constructing assets that turn out not to be required, wouldn't it be prudent for BC Hydro to acquire such information?

226.0 Reference: Portfolio Analysis
Exhibit B-3, BCUC IR 1.96.1

226.1 In describing the results of the unconstrained gas scenarios modeled in response to this IR, BC Hydro states that imports supply up to 3,700 GWh of average imports in the mid-load/mid Option A DSM; and up to 8,900 GWh/year of expected imports in the high-load/low Option A DSM. Please clarify whether these are net imports after taking into account non-firm energy available from clean domestic IPPs under average water years in each portfolio.

227.0 Reference: Portfolio Analysis
Exhibit B-3, BCUC IR 1.98.1

With respect to the Province's renewable energy target, BC Hydro states: "The 90 per cent clean or renewable target is with respect to the generation source and does not place requirements on the use of the electricity or its associated attributes." BC Hydro also states: "…the target is independent of whether the generation results in a surplus of energy above the amount required to meet domestic load or whether there is a shortfall that needs to be met by imports." In response to IR 1.92.1, BC Hydro indicated that: "The REC sales in any given year are calculated by multiplying the net positive of electricity exported by the corresponding REC price forecast shown in Figure 4-7 in the 2008 LTAP (Exhibit B-1). Three REC sales values are obtained by using a low, mid, and high REC price scenario."

227.1 Why has BC Hydro limited itself to the sale of RECs for net positive exports? BC Hydro does not seem to consider the sale of RECs associated with exports is inconsistent with the 90 percent target set out for total generation in the Energy Plan? Would the sale of additional RECs not be in rate payer interests if it reduces the cost of energy in B.C.? Is there another policy in the Energy Plan that suggests the sale of RECs associated with energy produced for domestic consumption is prohibited? Please clarify.

228.0 Reference: Portfolio Analysis
Exhibit B-3, BCUC IR 1.94.4

228.1 If the market heat rate is being used to compare with plants in B.C., should it not include the cost of wheeling and losses from Mid-C to the BC Border and would the addition of this not increase the market heat rates, all things being equal? Please provide a simple estimate of the percentage impact of including wheeling and losses in the market heat rate calculations for B.C.

229.0 Reference: Elasticity Analysis
BCUC IR 1.148.1
Attachment 1 Avista 2007 Electric Integrated Resource Plan, p. 2 of 8

"It is difficult to separate the interrelated impacts of rising electricity and natural gas prices, rising incomes and conservation programs. We only have data on total demand and must derive the impacts associated with consumption changes. The company has offered conservation programs to its customers since 1978. The impact of conservation on electrical usage is fully imbedded in the historical data; therefore, we concluded that existing conservation levels (5 aMW) are imbedded in the forecast."

229.1 Does BC Hydro consider that it faces the same issues as Avista in that it only has data on total demand and must derive the impacts associated with consumption changes?

229.2 Has BC Hydro incorporated the impact of rising income into the evaluation of DSM savings?

229.3 According to Appendix K, page 9 of 213, BC Hydro's DSM activities since 1989 have largely focused on influencing individual consumers with targeted programs. Please provide the estimates of DSM savings that are imbedded in the forecast.

230.0 Reference: Elasticity Analysis
Exhibit B-3, BCUC IR 1.7.1, Attachment 1, pp. 8, 9 of 9

The following questions seek to understand the impact on the economic potential for DSM, and the associated rate impacts, if own price elasticity should take on higher values than those assumed by BC Hydro, and if real rate increases of greater than zero persisted in the last ten years of the forecast.

230.1 Please prepare sets of tables for each of 2010, 2016, 2020, and 2028, showing the impact on the Annual 2008 Load Forecast in terms of annual induced energy savings, if it is assumed that: (1) company-wide own price elasticity takes on values of -.05, -.1, -.2,.-3, -.4, -.5, and -.6; and (2) assuming the annual real price increases as described for the first ten years, and in the last ten years of the forecast assume real annual price increases of 0, 1, 2, 3, and 4 percent. Please prepare separate tables for each of the reduced sales, and resulting total sales including the reduction, in the format shown below:

Year: 2010
Reduction in GW.h Sales (excluding losses)

	Annual Real Rrate Increase in Last Ten Years of Forecast				
Price Elasticity	0%	1%	2%	3%	4%
0.1					
0.2					
0.3					
0.4					
0.5					
0.6					

Year: 2010
Total Sales after Reduction (GW.h)

	Annual Real Rrate Increase in Last Ten Years of Forecast				
Price Elasticity	0%	1%	2%	3%	4%
0.1					
0.2					
0.3					
0.4					
0.5					
0.6					

230.2 What impact will any increase in price-induced savings have on the Economic Potential in terms of energy savings, and RIM and TRC values? In general how will the annual revenue-requirements rate increases be impacted if both higher elasticity and higher real price increases occur?

231.0 Reference: Elasticity Analysis
Exhibit B-3, BCUC IR 1.144.1
Exhibit B-1-1, Appendix E, pp. 5-7 of 28

231.1 Please provide information on the price elasticity assumptions used in the Annual 2008 Load Forecast in the same format as Table 1 of Appendix E.

231.2 Please explain BC Hydro's basis for asserting that "this level of consumer response would not be achieved based in the impact from rates alone". Does BC Hydro assert, for instance that long run price elasticities for the residential class of -.27 cannot occur in the absence of its programs and assumptions on codes and standards? If so please provide the empirical basis for this assertion.

231.3 BC Hydro states that "The use of the suggested elasticities as a representation of the consumer response resulting from the impact of rates alone would cause a significant double counting of DSM savings within the forecast." Assuming that the elasticity estimates are what they are defined to be, which is the percent change in consumption caused solely by a one percent change in the real electricity price, doesn't this mean that the "double counting" referred to would be an overestimation of the savings resulting from DSM programs?

232.0 Reference: Elasticity Analysis
Exhibit B-3, BCUC IR 1.146.2

232.1 Please provide an electronic spreadsheet containing the following annual data:

(a) From 1980 to 2005: electricity use per residential account, the average nominal price of electricity (residential), BC CPI, the real price of electricity,

(b) From 1990 to 2005: electricity use per residential account, the average nominal price of electricity, BC CPI, the real price of electricity, and nominal and real natural gas commodity prices (average quarterly price charged by Terasen Gas annualized).

232.2 Please prepare a summary table in the form of the response to BCUC IR 1.146.2 showing for the three time periods, the total percentage change in the real price of electricity, the total percentage change in real residential use per account, and the percentage total real change in the price of natural gas (where applicable).

233.0 Reference: Elasticity Analysis
Exhibit B-3, BCUC IR 1.150.1

233.1 What is the impact on savings attributable to DSM which would result from a higher estimate of price elasticity in so far as it is coupled only with a general real increase in rates, and not a change in rate structures?

234.0 Reference: Elasticity Analysis
Exhibit B-3, BCUC IR 18.1

234.1 Please provide the entire document for each study listed. For the UtiliPoint document, please provide the entire document including all appendices.

235.0 Reference: BRPs and CRPs
Exhibit B-3, BCUC IR 1.117.1
Exhibit B-1, p. 6-58
Exhibit B-3 BCUC IR 1.140.1

The IR asked if BC Hydro planned to the BRP or the CRP. BC Hydro referred the answer to Exhibit B-1. At page 6-58 of Exhibit B-1 BC Hydro states:

> "In a similar fashion, BC Hydro requests the BCUC's approval to submit the CRP to BCTC in either a NITS application or update so that BCTC will advance or maintain the required transmission facilities that permit the CRP resources to be utilized. Without BCTC formally including the CRPs in its planning processes and ensuring the CRP transmission requirements are being maintained, BC Hydro's CRPs would be ineffectual.

Attachment J to BCTC's OATT states:

> "The Transmission Provider will treat such applications as one service request. If there is sufficient ATC to meet Network Customer's service request which includes the Contingency Resource Plans, the Transmission Provider will reserve the transmission capacity for the Network Customer's service request in accordance with the queue priority of the Network Customers' NITS Applications. ***If there is insufficient ATC to meet the network Customer's service request, the Transmission Provider will conduct transmission studies in accordance with the Tariff and identify Network Upgrades for each load forecast scenario and for each resource plan contingency separately".*** (Emphasis added)

235.1 Please reconcile the highlighted statement from OATT with BC Hydro's statement that BCTC will advance or maintain the required transmission facilities that permit the CRP resources to be utilized.

235.2 Is it BC Hydro's position that it acquires the base "generation" resource while BCTC acquires the CRP (high load forecast) transmission resources?