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VIA E-MAIL
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July 10, 2008

BC HYDRO – 2008 LTAP
EXHIBIT A-2

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")

Attached please find Commission Information Request No. 1. Please provide ten hard copies and an electronic copy in your response. Pursuant to Commission Order No. G-96-08, BC Hydro is to respond to the Information Request by Thursday, August 21, 2008.

Due to the delay in the filing of the 2007 Conservation Potential Review and other documents (Exhibit B-1-4), staff intend to pursue Information Requests with respect to those documents in the Addendum in the next round Information Request No. 2.

Yours truly,

Original signed by:

Constance M. Smith
for: Erica M. Hamilton

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

REQUESTOR NAME: British Columbia Utilities Commission
INFORMATION REQUEST ROUND NO: 1
TO: BRITISH COLUMBIA HYDRO & POWER AUTHORITY
DATE: July 10, 2008
PROJECT NO: 3698514
APPLICATION NAME: 2008 Long Term Acquisition Plan (2008 LTAP")

1.0 Reference: LTAP Planning Cycle and Update Process
Exhibit B-1, Chapter 1, Introduction and Context, pp. 1-1, 1-2

BC Hydro proposes two modifications to the LTAP filing cycle. It proposes LTAP filing dates be made two years following receipt of the Commission's decision on the previous LTAP application, and it proposes to eliminate the IEP/LTAP nomenclature and refer to all future long-term resource plans as LTAPs. BC Hydro clarifies its proposal by stating that it is not advocating for the elimination of an IEP-type analysis in future LTAPs.

In the 2006 IEP/LTAP Application the 2006 LTAP was described as an action plan (F2006 to F2015), supported by the 20-year 2006 IEP horizon, which itemized the actions BC Hydro proposed to take in the next ten years to meet the future load/resource balance.

On page 1-1 of the 2008 LTAP, BC Hydro describes the 2008 LTAP as a plan that covers the next ten years (F2009 to F2019) and on page 6-1, it presents the 2008 LTAP as a plan which identifies the steps BC Hydro proposes to take during the next two to three years.

1.1 Notwithstanding the IEP-type analysis accompanying the 2008 LTAP, given the time-frame used in the 2008 LTAP described above, is it BC Hydro's position that the "long-term resource plan" within the meaning of Sections 44.1(2) and 44.1 (4) of the amended *UCA* is shortened from 20 years to ten years and the "long term acquisition plan" is shortened from ten years to "two to three years"? If not, please explain BC Hydro's view.

2.0 Reference: LTAP Update Process
Exhibit B-1, Chapter 1, Introduction and Context, p. 1-5
Planning Objectives

BC Hydro has not updated its planning objectives for the purposes of the 2008 LTAP.

2.1 Given the criterion under Special Direction 10 § 3 (Appendix B2), should achieving self-sufficiency be included as a new planning objective?

2.2 Please comment which planning objective(s) the following new initiatives described in the 2008 LTAP are designed to achieve: (a) the new DSM residential Low Income program; and (b) for the years after 2015 the removal of 2,500 GWh/year non-firm market allowance and the 400 MW market reliance.

3.0 Reference: LTAP Update Process
Exhibit B-1, Chapter 1, Introduction and Context, Section 1.2.1, LTAP Update Process, p. 1-5

3.1 At line 12 it is stated that throughout the 2006 IEP/LTAP there was recognition that reliability is a minimum constraint rather than an objective to be traded off against other objectives. On what basis was the recognition made? Please provide references to the prior application or decision.

3.2 How are the reliability minimums determined?

4.0 Reference: Order Sought
Exhibit B-1, Section 1.1.2, Order Sought; Exhibit B-1-1, Appendix A, Draft Order

In the 2008 LTAP, BC Hydro seeks Commission approval, determinations and endorsements of various items of its proposed action plan.

4.1 In BC Hydro's view, is there a difference between accepting, endorsing or approving a plan or action? Please explain why certain items are specifically sought for endorsement as opposed to determination or approval.

5.0 Reference: Order Sought
Exhibit B-1, Section 1.1.2 Order Sought
Proposed Actions in 2008 LTAP

5.1 Please provide an expenditure schedule in tabular format for the steps BC Hydro proposes to take in the next two to three years to implement the 2008 LTAP and the portion of expenditures between F2009 and F2019 which are or will be included in other BCUC proceedings. An example of the format of the expenditure schedule is provided below.

Order Sought in 2008 LTAP	**F2009**	**F2010**	**F2011**	**Total**	**Expenditures (F2009 – F2019) Not Sought in 2008 LTAP**
DSM Implementation Plan	$112.1 m	$138.2 m	$167.7 m	$418.0 m	$? for rate structure $? for information technology
Definition Phase for CF DSM	$0.6 m		$0.0	$0.6 m	$? Implementation Phase Plan
Burrard – Short Term Reliability	$0.0 m	$1.6 m sustaining capital	$0.0 m	$1.6 m	$55-$127 million for the years 2010 to 2012
Definition Phase for Mica Units	$ 29.9 m			$29.9 m	$? range

Stage 2 (Project Definition Consultation) for Site C	$ 41.0 m		$0.0 m	$0.0 m	$? range
Definition Phase for Clean Power Call	$2.0 m		$0.0 m	$0.0 m	$? range
Bioenergy Call – two phases	$0.0 m				$?
Definition and Implementation Phases of the FNGU	$59.0 m			$59.0 m	$? range
TOTAL sought in 2008 LTAP					

6.0 Reference: Alignment with 2007 Energy Plan
Exhibit B-1, Chapter 1, Introduction and Context, Section 1.2.3, B.C. Government Legislation and Policy, p. 1-7

6.1 Does BC Hydro interpret the objective of electricity self-sufficiency as a matter for BC Hydro, or for the Province as a whole?

7.0 Reference: Alignment with BCUC Decisions
Exhibit B-1, Section 1.2.4, BCUC 2006 IEP/LTAP Decision, p. 1-14

7.1 Further to the Undertaking No. 7 by BC Hydro in the Residential Inclining Block Rate proceeding (Exhibit B-28 pages 1 to 7 of 7), please provide the financial forecast of BC Hydro's rates in both real and nominal terms for twenty years.

7.2 Where there are differences between those numbers filed in Exhibit B-28 of the RIB proceeding and used as inputs to the 2007 Load Forecast and the numbers as contained in the above report, please highlight the differences and comment on the effects as a result of those differences.

8.0 Reference: Natural Gas Price Forecast
Exhibit B-1, Chapter 1, Introduction and Context, Section 1.2.6 Power Industry Market Trends, p. 1-17

8.1 Please confirm that Global Energy both prepared the price forecasts, and then assigned probabilities to their own forecasts.

8.2 Please discuss the relative merits of the approach taken vis-à-vis an approach where each of the three forecasts is defined: (1) to be equally likely (2) to have a mid forecast designed to be 50 percent likely and high and low forecasts to be 25 percent likely; and (3) the high and low forecasts are designed to yield equal probabilities of (say) 10 percent or less with the mid forecast designed to the residual probability.

9.0 Reference: 2007 Load Forecast: Trends and Key Uncertainties
Exhibit B-1, Section 2.2.2, Key Trends, p. 2-6
Exhibit B-1-1, Appendix D, p. 47 of 103 Industrial Forecast

The 2007 Load Forecast for the Industrial sector reflects the impact on recent trends such as an appreciation in the Canadian dollar, a slow down in the U.S. housing starts and lower demand for pulp and paper.

9.1 The forecast methodology for the Industrial sector includes the use of forecast GDP in a regression model to develop the long-term sales forecast for the larger transmission non-forestry sectors. Has BC Hydro attempted to use a CDN:USD currency index or trade weighted index of the Canadian dollar in addition to GDP when building the forecast model? If not, why not? If so, why did it reject that approach?

10.0 Reference: 2007 Load Forecast: Methodology
Exhibit B-1, Chapter 2, Load Resource Balance, Section 2.1.1,
2007 Load Forecast Methodology Overview, p. 2-2

10.1 At line 13 it is stated that Electric Plug-in Vehicles ("EPV") have not been specifically factored into the load forecast. Please explain the use of the word "specifically" – have EPV's been factored in any manner?

11.0 Reference: 2007 Load Forecast: Methodology
Exhibit B-1, Chapter 2, Load Resource Balance, Section 2.2.1
2007 Load Forecast Methodology Overview, p. 2-4

Directive 17 from the 2006 IEP/LTAP Decision is quoted as:

> "17. The BCUC's determination in section 6.2 of the Decision directed BC Hydro to file financial forecast of BC Hydro's rates in both real and nominal terms, for a minimum of ten years, but preferably 20 years. The BCUC Panel further directs BC Hydro to rely on the report for assumptions regarding retail prices in each of the Conservation Potential Review (CPR), the load forecast, and DSM evaluation methodologies."

11.1 Was the 20 year financial forecast used in the 2007 CPR? Please provide the forecast of BC Hydro rate increases used in the 2007 CPR.

11.2 Please provide any DSM evaluations which have been undertaken that employed the 20 year financial forecast.

12.0 Reference: 2007 Load Forecast: Methodology
Exhibit B-1, Chapter 2, Load Resource Balance, Section 2.2.1
2007 Load Forecast Methodology Overview, p. 2-5

12.1 It is stated that Highland Valley Copper's contribution to demand is disproportionately larger than their contribution to GDP. Please provide HVC's load as a percent of BC Hydro's total load on both a capacity and energy basis (for, say, 2007), and also provide HVC's percentage

contribution to provincial GDP on both a direct and direct plus indirect basis, using a GDP multiplier that BC Hydro feels is reasonable. Does BC Hydro make any other offsetting adjustments to account for industries whose contribution to GDP is disproportionately larger relative to their electricity demand? If not, why not.

12.2 Regarding the unbilled accrual, it is stated that the "…modifications to include accrued sales would involve extensive computations to develop a revised history." Please reconcile this with the statement of BC Hydro's witness in the 2006 IEP/LTAP proceeding that the monthly accrual calculation was more or less automatic.

13.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28, pp. 1, 9 of 103

13.1 What is the date of the document?

13.2 Please provide the substation forecast that is consistent with this document. If there are differences please reconcile the documents in tabular format.

14.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28, p. 14 of 103

14.1 Please confirm that the temperature used in preparing the substation peak forecast is different, and lower, than the temperature used for the system peak forecast.

14.2 If confirmed, please explain why different temperatures are used for the substation and system peak forecasts.

15.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28, p. 26 of 103

15.1 Regarding the forecast band resulting from simulation and historical forecast accuracy, BC Hydro states: "There appears to be a decrease in the variance in the long-term projections over successive forecasts. This decrease is closer to the prospective range of the current forecast uncertainty bands which is about 4.4% 10 years into the future." This is in apparent reference to the parenthetical values in Table 5.1. Does BC Hydro agree that the same information indicates that the band should be asymmetric since all variances are negative?

16.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28, p. 28 of 103

16.1 Please provide a table showing usage per residential account from 1990 to 2028 on an actual and weather normalized basis as well as the number of accounts.

17.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28, p. 30 of 103

17.1 In light of the RIB application, please explain why increased electric space heating market share was assumed.

17.2 Housing units are expected to be smaller yet appliances are expected to be larger in size and more numerous. Please explain why these assumptions are consistent. Are these merely assumptions or does BC Hydro have empirical evidence or third party analyses justifying these assumptions? Please provide any studies or empirical evidence relied on.

18.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28, p. 33 of 103

18.1 Please provide a list of all studies (and their executive summaries) conducted by or for BC Hydro since 1978 that performed statistical/econometric estimations of price elasticity and or cross price elasticity related to BC Hydro or B.C.

19.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28, p. 34 of 103

19.1 Please provide a table in the same format as Table 6.1 for peak demand and show sales and losses separately.

20.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28
pp. 42-45 of 103

20.1 Please confirm that the forestry sector is the only sector in which a more specific approach has been used to enhance the methodology.

20.2 Please prepare in tabular format, for all years of the Load Forecast, a table showing by customer, sawmills and pulp mills that have publicly announced shutdowns since the forecast was produced, and show the associated demand and energy including losses.

20.3 Please provide documentation showing that economists expect the slowdown in the US housing market will last into 2009.

20.4 Please explain the phrase "customers with self generation will continue reducing sales in response to new rates" found at page 45.

21.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28
pp. 46-47 of 103

21.1 Please provide the annual energy and demand associated with the three large potential mining projects. Have the projects been announced to the public by the owners?

21.2 Have the closures of the two coal mines been announced by the companies?

21.3 What was the expectation regarding Highland Valley Copper in the 2006 IEP/LTAP?

21.4 Regarding the use of regression analysis with customer specific adjustments for industrial distribution: over the medium to long term, what assurance does BC Hydro have that such adjustments are not already included in the regression results and thus may be double counted?

22.0 Reference: 2007 Load Forecast Methodology
Exhibit B-1-1,Appendix D, Commercial Forecast, pp. 38 & 69 of 103

22.1 Does BC Hydro have research results to compare the relative sensitivity of Residential and Commercial customers to weather? If one of the factors leading to higher than forecast commercial sales is substantially warmer summers or colder winters than normal, is BC Hydro applying weather normalization to Commercial customers' sales in the 2007 Annual Load Forecast?

23.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28
pp. 68-73 of 103

23.1 Are each of historical commercial and residential sales normalized for cooling effects? Please answer with reference to the statement on page 73 regarding the inclusion of HDD and CDD in regional models, and the statement at page 80 in the first paragraph of the "Analysis for 10 year Historic Data".

23.2 Please provide the complete derivation of equation A1.6 on page 71.

24.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28
pp. 74-76 of 103

24.1 Please re-estimate Model A1.10 on page 74 including a time trend.

24.2 Please confirm that Model A1.11 was estimated by OLS in log-linear form. Is the DW statistic valid in this case?

24.3 Please estimate Model A1.12 including a time trend.

25.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28, p. 82 of 103

25.1 If the extrapolation of average temperature was made for 20 years and showed an increase of 0.24 degrees C, what impact would this have on the forecast in the 20th year?

26.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28, p. 87 of 103

26.1 Please comment on the following statement: BC Hydro's energy load forecast methodology produces an expected energy forecast since it uses 10 year expected degree days, while the peak forecast is an extreme forecast since it use the lowest average daily temperature which occurred in the last 30 years.

27.0 Reference: Load Forecast Methodology
Exhibit B-1-1, Appendix D, Electric Load Forecast 2007/2008-2027/28
pp. 98-103 of 103

27.1 Please provide each of the Tables on these pages as fully functioning spreadsheets.

28.0 Reference: Existing and Committed Resources
Exhibit B-1, Chapter 2, Load Resource Balance, Section 2.3.2
Heritage Thermal – Burrard Generating Station, p. 2-11

28.1 Assuming Burrard is available at its full capacity of 900 MW, and assuming DSM Option A, is it possible to defer ILM assuming N-1 Transfer capability of 5000 MW. If yes, for how many years can ILM be deferred? Please provide the load resource balance for LM/VI under these circumstances.

28.2 Assuming Burrard is available at it full capacity of 900 MW, and assuming DSM Option B, is it possible to defer ILM assuming N-1 Transfer capability of 5000 MW. If yes, for how many years can ILM be deferred? Please provide the load resource balance for LM/VI under these circumstances.

29.0 Reference: IPP supply and Attrition Rate for Past Calls
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.3.5
Existing (Pre F2006) IPP Supply Contracts and Alcan EPA, pp. 2-12 to 2-13

29.1 In Footnote 23, BC Hydro states: "BC Hydro assumes these eight sites will contribute 400 GWh of energy or 50 MW of dependable capacity in F2012, including attrition, to the Load/Resource Balance. A higher attrition factor has been used for these sites (76 per cent attrition factor)". Please explain the rationale for the higher attrition factor and what was assumed in the 2006 IEP/LTAP.

29.2 BC Hydro states: "BC Hydro has assumed that three existing biomass contracts will not be renewed upon EPA expiry (between F2014 and F2022) due to pricing and fuel supply risks." Please discuss BC Hydro's rationale in more detail, and discuss whether this statement may also apply to the likelihood of contracts from the Bioenergy calls.

29.3 BC Hydro states: "Energy and capacity from the Alcan 2007 EPA are included in the supply stack, amounting to 900 GWh of firm energy and 200 MW of dependable capacity in F2012." Please confirm whether these assumptions are consistent with the Commission decisions with respect to the 2007 Alcan EPA, which stated in part at page 42: …the Commission Panel accepts a FELCC of 757 aMW for the purposes of BC Hydro's economic evaluation, which is still greater than the Tier 1 Electricity quantity of 730 aMW established in the 2007 EPA…"

30.0 Reference: IPP supply and Attrition Rate for Past Calls
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.3.7,
Attrition Rate for Past Calls, p. 2-14

30.1 BC Hydro includes the VICFT in its estimates of past attrition rates. As that project was cancelled by BC Hydro rather than the project proponent, please provide a new version of Table 2-5 excluding the VICFT from the calculation of total historical attrition rates.

31.0 Reference: Existing and Committed Resources
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.3.8, SOP, p. 2-14

31.1 Please provide a summary of the derivation of the SOP volumes in the SOP Application for the record in this proceeding.

31.2 Are the assumed volumes consistent with the FELCC methodology proposed in Appendix F12 of the 2008 LTAP Application?

32.0 Reference: Existing and Committed Resources
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.3.10, Energy, p. 2-16

32.1 Table 2-7 shows a reduction of 700 GW.h in existing clean or renewable IPPs. In Section 2.3.5, BC Hydro identified a reduction of only 400 GW.h by F2012. Please summarize in detail all of the factors contributing to the 700 GW.h reduction in Table 2-7.

32.2 In Section 2.3.6, BC Hydro identified about 400 GW.h of small hydro from the F2006 Call that had been added to the firm energy stack. Table 2-7 shows a 300 GW.h increase. Please explain.

33.0 Reference: SD 10 Impact on Resource Requirements
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.3.11, SD 10 Impact on Resource Requirements, pp. 2-17 to 2-18 AND Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.9.4 Long Portfolio Impacts / Exposure to External Markets, Table 5-48, p. 5-93

33.1 BC Hydro states: "The 2,500 GWh/year non-firm/market allowance has been removed from the 2008 LTAP energy load/resource balances after 2015. The 2,500 non-firm/market allowance consists of three components: (1) Heritage hydro non-firm energy, (2) imported non-firm energy and (3) domestic IPP non-firm energy. SD 10 precludes reliance on Heritage hydro nonfirm energy. SD 10 also provides that external markets cannot be relied upon after 2015 for purposes of meeting BC Hydro's mid-level energy and peak forecasts. The third component - domestic IPP non-firm energy - has been included in the load/resource balance pursuant to FELCC studies as described above and in Appendix F12." Please provide a summary comparison of the net change of relying on FELCC in the 2008 LTAP compared to the reliance on contractual firm energy and a 2,500 non-firm allowance in the 2006 IEP/LTAP.

33.2 BC Hydro states: "The 400 MW market reliance for has been removed from the capacity load/resource balances after 2015, as the 400 MW relies on external markets and is not a domestic resource. Reliance on the estimated market for capacity in the 2008 LTAP is reflected in the contingency resource reliance on the CE." Please discuss in more why BC Hydro had interpreted SD10 to exclude reliance on external capacity for reserves, when reserves are rarely required. Please discuss whether this is explicit in the policy or subject to interpretation. Please discuss whether a different interpretation may be reasonable given the Energy Policy also notes the continued value of trade for optimizing the system. Can BC Hydro point to any explicit government policy concerning the continued reliance on external reserves?

33.3 Please provide a summary of the portfolio modeling results for the Base 11 Scenarios in Table 5-48 assuming continued reliance on 400 MW of external reserves in the portfolio construction (i.e., within the System Optimizer Model runs used to produce the portfolios).

34.0 Reference: Load/Resource Balance
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.4
The Load/Resource Balance, p. 2-18

34.1 On Figure 2.5 please describe the "DSM in the Operating Period".

34.2 Please provide the data underlying Figures 2-5 and 2-6 in tabular and electronic spreadsheet form.

35.0 Reference: Load Resource Balance
Exhibit B-1, Section 2.4, Energy Load/Resource Balance, Figure 2-5
Non-firm/Market Allowance

35.1 On page 2-17, the BC Hydro states that the 2,500 GWh/year non-firm/market allowance has been removed from the 2008 LTAP energy load/resource balances after 2015. Is the reference to 2015 the calendar year or the fiscal year? Please explain why it is included in F2016 in Figure 2-5.

36.0 Reference: Load/Resource Balance
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.4,
The Load/Resource balance, pp. 2-18 to 2-19

36.1 Please describe whether and how the energy load/resource balance in Figure 2-5 incorporates the government's requirement for 3,000 GW.h of insurance by 2026.

36.2 How does BC Hydro define this insurance requirement and how has it been addressed in the portfolio analysis?

36.3 Please explain the non-firm / market allowance to F2016 in light of the discussion of the allowance in previous sections.

37.0 Reference: Fort Nelson Load Resource Balance
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.5.1
Fort Nelson, pp. 2-20, 21

37.1 In Figure 2-7 why is the Low Scenario peak demand higher than the Reference forecast?

37.2 At line 11 it is stated that "There is a possibility of a significant increase in industrial demand in the region which, absent new supply resources, BC Hydro will not be able to serve." At line 16 of page 2-2 of Exhibit B-1 it states: "Similarly, with respect to the possibility of load reductions due to industrial customer attrition, BC Hydro includes into its forecast verifiable information regarding specific customer loads. The closure assumption concerning Highland Valley Copper, for example, is based on public domain information provided by the customer." Are the load increases in Fort Nelson based on public domain information supplied by the customers? If so please provide the information. If not, should the expenditures proposed by BC Hydro be based on information that is not as verifiable as in the HVC case?

37.3 Please provide the data underlying Figure 2-8 in both tabular and fully functioning spreadsheet form.

37.4 Please provide the same information as portrayed in Figure 2-8 in graphical, tabular and fully functioning spreadsheet form assuming N instead of N-1.

38.0 Reference: Fort Nelson Load/Resource Balance
Exhibit B-1, Section 2.5.1, Fort Nelson, p. 2-20
Reference Forecast and Scenarios, Exhibit B-1-1, Appendix N1, pp. 16, 17 of 84

Fort Nelson's medium to long-term customer load growth potential is for up to an additional 60 MW to 70 MW by 2013. This represents a 200% increase from the current load. This load growth is being driven by the development of new industries, primarily in the oil and gas sector. Much of the new load is load that the potential customers could meet by either gas or electric drive systems.

38.1 Please confirm that much of the new load is load that potential customers could meet by either gas or electric drive system.

38.2 What was the cumulative increase in load in the last five years (2002 to 2007)? What was the cumulative increase in load in the last ten years?

38.3 Figure 2-7 shows three scenarios of future load growth in addition to the Reference Forecast for the region. Please provide the underlying assumptions to the four scenarios.

38.4 Each of the scenarios was developed using a bottom-up forecasting methodology based on information gathered in confidence from potential customers and assessed by BC Hydro. Does BC Hydro have a top-down approach such as a macro view of how sustainable the oil and gas industry is in the short-, medium- and long-term? Please explain how BC Hydro assesses the likelihood of the customers' projects proceeding.

38.5 Has BC Hydro assigned probabilities to the scenarios in Figure 2-7 on page 2-20 to reflect the significant uncertainty with respect to future customer demand in the region (X-reference: Appendix N, p. 15 of 84)?

39.0 Reference: Fort Nelson Resource Plan
Exhibit B-1-1, Appendix N, Section 1.5.5.2, Contract Sales

39.1 How many times in the last ten years have sales arrangements been made for exports to Alberta from the excess FNG production? Please provide details of the energy sales and sales of the reliability-based service TMR.

40.0 Reference: Fort Nelson Resource Plan
Exhibit B-1-1, Appendix N, Section 1.5.7.1, B.C. Lower Mainland Price

40.1 Are the electricity prices depicted in Figure 1-8 identical to those forecast prices in Figure 4-6 in Exhibit B-1? If not, please explain the differences.

41.0 Reference: Lower Mainland Load/Resource Balance
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.5.2,
Lower Mainland/ Vancouver Island, pp. 2-22, 23

41.1 At line 7 the phrase "no new DSM" is used. Please explain this phrase and the underlying assumptions regarding EE2, EE3, EE4, and EE5.

41.2 Please provide Figures 2-9 and 2-10 in tabular and fully functioning spreadsheet form.

41.3 Please provide Figures 2-9 and 2-10 in graphical, tabular and fully functioning spreadsheet form and showing the load forecast reduced by each of DSM Option A and Option B.

41.4 Why is the next Call not shown as impacting the resource stack? Please include the impact in the next call if it serves to increase coastal generation.

42.0 Reference: Lower Mainland Load/Resource Balance
Exhibit B-1, Chapter 2, Load and Resource Balance, Section 2.5.2, Lower Mainland / Vancouver Island, pp. 2-21 to 2-23

42.1 Please provide versions of Figures 2-9 and 2-10 showing the LM/VI Load Resource Balances after DSM. Please highlight the required timing of 5L83 with DSM.

43.0 Reference: DSM ROU
Exhibit B-1, Section 3.2.1.1, Codes and Standards, Table 3-1
Building Code

Table 3-1 lists the codes and standards included in Options A and B, together with the level of Government responsible.

43.1 In April 2008, Commission Order No. G-1-08 granted a CPCN for the construction and operation of a sustainable development certified by the Canada Green Building Council's Leadership in Energy and Environmental Design (LEED ™). In BC Hydro's view, would savings in electricity, if any, be counted towards DSM savings? If they are not counted towards DSM, are the savings considered as natural conservation in the Load Forecast?

43.2 If a LEED ™ building contributes to DSM, how are savings reflected in the DSM Plan and annual Load Forecast?

44.0 Reference: DSM ROU
Exhibit B-1, Section 3.2.2, Option A and Option B, pp. 3-7, 3-8

The Application states that Options A and B were used in the 2008 LTAP portfolio analysis because they represent feasible DSM options within the constraints established by government policy and resource planning requirements.

44.1 Please provide examples of the constraints described above.

45.0 Reference: DSM ROU
Exhibit B-1-1, Appendix F17, Table 3, Inclining Block Rate

45.1 Table 3 shows the Residential consumption threshold for Option A at 1,350 kWh/month and for Option B at 800 kWh/month. Given the recent proceeding on the RIB application where BC Hydro applied for a bi-monthly Step-1 threshold of 1,600 kWh, is BC Hydro choosing Option B for the Residential rate structure?

46.0 Reference: Summary of DSM Option A and Option B
Exhibit B-1, Chapter 3, Resource Options, Section 3.2.2
Summary of DSM Option A and Option B, p. 3-7

46.1 It is stated that Policy Action Number 3 called on utilities "to pursue all cost-effective investments in demand side management". Please provide an estimate of the maximum demand and energy saving from all cost-effective demand side management available. If this necessitates assuming increased incentives or activity levels please do so. Has BC Hydro pursued ***all*** cost effective DSM?

47.0 Reference: DSM ROU
Exhibit B-1, Chapter 3, Demand Side Management, Section 3.2.1.2
Rate Structures Energy Savings and Avoided Energy

The response to BCUC IR 1.79.6.1 in the F2009/F2010 Revenue Requirements Application showed in F2009 a reduction of energy sales of 88 GWh. If the DSM expenditures were all expensed there would be a corresponding cost of energy savings of $2.2 million (see below).

($ million)	F2009	F2010
Increase in Revenue Requirements:		
Cost of Energy	(2.2)	6.5
Finance Charges	(2.4)	(7.6)
Return on Equity	(2.3)	(6.4)
Regulatory Accounts	105.0	111.5
Total	98.1	104.0
Increase in Revenue at Current Rates	(4.6)	(4.5)
Required Rate Increase	10.17%	8.09%
Reduction in Energy Sales (GWh)	88	86

The response to BCUC IR 2.55.2 in the Residential Inclining Block ("RIB") Rate Application indicated that a 204 GWh/year reduction in energy consumption would result in $21 million (real $F2010) of energy cost savings.

47.1 Please reconcile the unitized $/GWh savings in the two responses above ($2.2 million /88 GWh = $25,000/GWh; $21 million /204 GWh = $102,941/GWh).

47.2 What is the All Ratepayers Test ratio for an accounting change to fully expense DSM expenditures into rates?

47.3 Is demand side management conservation via price signals more cost effective than program spending (i.e., Power Smart)?

48.0 Reference: DSM ROU
Exhibit B-1, Chapter 3, Demand Side Management, Section 3.2
Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. ("Terasen Utilities")
Energy Efficiency and Conservation Programs Application, p. 35, Table 3.5,
Summary Information Other Utilities DSM Activity

Table 3.5 - Summary Information Other Utilities DSM Activity

Company Name	Utility Type	2007 DSM Annual Budget ($ in millions)	Start DSM year	DSM Funding Treatment	Company Same as DSM	Customer Base	FTE DSM Employees	Total Employees	2006 Assets (base (i.e. in millions)	2006 Total Revenues ($ in millions)	% Spent on DSM of Revenue	DSM Spend per customer	2006 Annual Sales Volume (PJs)
Pacific Gas and Electric Company ("PG&E")	Combined	278.0	mid-1970's	Public Purpose Fund	Yes	4,200,403	350	20,000	34,800	12,530	2.23%	$66.43	426.6
Manitoba Hydro	Combined	9.0	1989	DSM costs are treated as capital and amortized over a fixed time period	No	250,000	50	3,200	11,000	617	1.74%	$34.88	147.2
Southern California Gas Company ("SoCal Gas")	Natural Gas	66.5	mid-1990's	Public Purpose Fund	Yes	5,600,000	30	3,000	8,300	4,100	1.35%	$10.31	846.5
BC Hydro and Power Authority ("BC Hydro")	Electric	62.9	late-1980's	DSM costs are treated as capital and amortized over a fixed time period.	Yes	1,704,873	131	4,200	12,484	4,311	1.21%	$30.68	100.5
FortisBC	Electric	2.5	1989	DSM costs are treated as capital and amortized over a fixed time period.	Yes	154,000	5	570	791	208	1.19%	$16.06	1 : .1
Northwest Natural Gas Company ("NW Natural")	Natural Gas	11.0	1990	Public Purpose Fund	No	638,000	1	1,211	1,957	1,009	1.10%	$17.30	125.8
Union Gas	Natural Gas	17.0	1997	DSM costs are recovered through rate base	Yes	1,300,000	45	2,200	4,600	2,100	0.81%	$13.08	1,368.0
Enbridge Gas Distribution ("Enbridge")	Natural Gas	22.0	1995	DSM costs are recovered through rate base	Yes	1,650,000	45	1,981	3,321	3,016	0.73%	$13.33	445.0
Kelowna Gas Partnership ("Gaz Metro")	Natural Gas	4.5	1998	as O&M	Yes	167,000	6	1,500	2,700	3,000	0.44%	$26.95	221.8
Inland Gas Utilities	Natural Gas	4.3	1991	Program costs as O&M, program incentives are amortized over fixed time period	No	811,334	4	1,237	2,500	1,598	0.26%	$4.80	200.0
Puget Sound Energy ("PSE")	Combined	6.1	early-1990's	DSM costs are recovered via a rider on customer bill	Yes	710,000	65	2,400	7,061	2,909	0.21%	$6.02	205.1
SaskEnergy	Natural Gas	1.6	2001	as O&M	No	335,000	4	1,000	1,529	1,374	0.11%	$4.82	125.0
ACTO Gas	Natural Gas	Part of marketing budget	2001	as O&M	No	359,200	8 - 12	1,700	7,588	2,880	n/a	n/a	218.0

48.1 The Terasen Utilities included the preceding Table 3.5 in their Energy Efficiency and Conservation Programs Application ("Terasen Utilities-Table 3.5"). Please provide a similar comparison of DSM Activity by other relevant utilities.

48.2 The DSM Funding Treatment listed in Terasen Utilities -Table 3.5 for Puget Sound Energy shows that DSM costs are recovered through a rider on customers' bills. What is BC Hydro's view of recovering DSM through a rider on customers' bills as opposed to BC Hydro's current treatment of amortizing DSM costs over a fixed time period?

48.3 Please explain the treatment of DSM cost recovery that is allowed under Generally Accepted Accounting Principles ("GAAP"). Is DSM cost amortization over multiple years allowed under GAAP?

49.0 Reference: DSM ROU
Exhibit B-1, Chapter 3, Resource Options, Section 3.2.1.3, Programs, pp. 3-5 to 3-10

49.1 Please explain what is meant by Load Displacement. Does this include customer-based generation?

49.2 Please explain how the inclusion of customer-based generation in a definition of DSM is consistent with Energy Policy 1 which states: "Set an ambitious conservation target to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020." [Emphasis added] Discuss this also in light of other government policies to support customer-based generation including net metering and the Standing Offer Program.

49.3 How does BC Hydro determine when it is appropriate to offer additional incentives for customer-based generation versus reliance on the incentives already provided by electricity prices (including the inclining block rate), net metering, and the standing offer program?

49.4 If there are targets for customer-based generation in BC Hydro's DSM programs, please explain what steps BC Hydro took to ensure there was not any double counting between the savings attributed to the DSM programs and the additional supply attributed to the SOP.

49.5 Please provide new versions of Tables 3-4, 3-5, 3-6, 3-7, and 3-8 with the contribution from customer-based generation separated from other programs.

50.0 Reference: DSM ROU
Exhibit B-1-1, Appendix F17, Demand Side Management Resource Options, Table 4: Programs in DSM Options A and B

50.1 Residential load displacement appears to represent <1% of total savings but >20% of the total ratepayer costs for residential programs. Please explain the rationale for pursuing such programs.

50.2 Please explain why Option B has smaller savings associated with Residential Behaviour Programs but the same overall cost.

50.3 Please provide a new version of Table 4 in which programs are ordered from lowest cost (i.e., Total Ratepayer Cost / Total Savings). Please provide an accompanying chart that shows the cumulative savings (Y Axis) against cumulative costs (X Axis) of programs for the each of the residential, commercial and industrial sectors.

51.0 Reference: Small Hydro ROU
Exhibit B-1, Chapter 3, Resource Options, Section 3.3.2.2, Results, pp. 3-13, 14

51.1 Please provide Tables 3-10 and 3-11 excluding sites located in fish bearing portions of streams.

52.0 Reference: Wind ROU
Exhibit B-1, Chapter 3, Resource Options, Section 3.3.4.2, Results, p. 3-20

52.1 At line 4 it states that the costs for wind turbines have increased to meet increased demand. Since the wind bundles do not generally appear for several years, are BC Hydro's cost assumptions based on wind turbine prices that reflect supply/demand equilibrium. If not, wouldn't it be appropriate to do so? Why or why not?

53.0 Reference: Wind ROU
Exhibit B-1-1, Appendix F3, Wind Integration Cost Assessment, pp. 3, 4 of 17

53.1 Please recalculate the mid-mid scenario assuming wind integration costs of $0 and $20 and show the resulting resource stack relative to the $10 assumption.

54.0 Reference: Natural Gas-Fired Generation ROU
Exhibit B-1, Chapter 3, Resource Options, Section 3.3.7.1, Methodology, p. 3-24

54.1 Please provide a summary table comparing the cost of the small cogeneration projects noted beginning at line 4, escalated at CPI and the MMK escalation. If MMK had been used, how would this have affected the results?

55.0 Reference: Waneta Expansion Project
Exhibit B-1, Chapter 3, Resource Options, Section 3.3.10, Waneta Expansion Project, p. 3-30

55.1 What is the dependable capacity of WAX in December-January?

56.0 Reference: Summary of Resource Options Update
Exhibit B-1, Chapter 3, Resource Options, Section 3.3.14, pp. 3-35 to 37

56.1 Please provide Tables 3-21 and 3-22 in fully functioning spreadsheet format and including dependable capacity.

57.0 Reference: Load/Resource Balance
Exhibit B-1-1, Appendix F12, Effective Load Carrying Capability/Firm Energy Load Carrying Capability of Intermittent Resources, Section 1.2.2.2, Wind FELCC – Existing and New Resources, p. 6 of 17

57.1 BC Hydro states: "No additional FELCC analysis was undertaken in the 2008 LTAP for 2006 CFT wind projects or any new wind projects identified in the 2008 Resource Options Update. The FELCC contribution of the three wind projects awarded contracts in the F2006 CFT Large Project stream was assumed to be equal to their contractually firm energy." Why? How does BC Hydro account for potential diversification benefits across different sites in this approach?

57.2 How does BC Hydro's approach to wind take into account potential diversification effects from a combination of wind and hydro in a portfolio?

57.3 Please explain whether and how BC Hydro's estimate of FELCC for particular resources may vary with the overall composition of different portfolios.

58.0 Reference: Alignment with 2007 Energy Plan, UCA Amendments, and BCUC Decisions
Exhibit B-1-1, Appendix F12, Effective Load Carrying Capability/Firm Energy Load Carrying Capability of Intermittent Resources, Section 1.2.3.2, Wind ELCC – Existing and New Resources, p. 11 of 17

58.1 BC Hydro states: "The ELCC of wind resources are treated the same as in the 2006 IEP/LTAP. The ELCC for on-shore and off-shore projects will be assumed to be 21 per cent and 29 per cent of installed capacity respectively." How does BC Hydro account for potential diversification benefits across different sites in this approach?

58.2 How does BC Hydro's approach to wind take into account potential diversification effects from a combination of wind and hydro in the portfolio?

58.3 BC Hydro's approach seems to adjust for individual projects but should ELCC not also be a function of the combination of projects in the portfolio (location and type) and therefore potentially vary under different portfolios?

59.0 Reference: Resource Options (General)
Exhibit B-1, Appendix F12, Effective Load Carrying Capability/Firm Energy Load Carrying Capability of Intermittent Resources, 1.4 Extract from the 2007 Standing Offer Program (SOP application), p. 15

59.1 BC Hydro states that it analyzed FELCC from the SOP assuming existing and committed resources. BC Hydro's filing indicated it assumed a firm energy contribution from Burrard of 6,100 GW.h in the SOP analysis. Does the proposed reduction in the firm energy contribution of Burrard to ~3,000 GW.h in the 2008 LTAP alter in any significant way the results of the SOP analysis?

60.0 Reference: Financial Assumptions
Exhibit B-1, Chapter 3, Resource Options, Section 3.5.1, Cost of Capital, p. 3-42

60.1 Is the 6% nominal cost of debt an embedded or marginal debt rate and is this consistent with the Commission's determination in the 2006 IEP/LTAP decision?

60.2 The 2008 LTAP states that a nominal discount rate of eight per cent was utilitzed in the ROU. Please provide BC Hydro's assumptions on IPPs capital structure.

61.0 Reference: Financial Assumptions
Exhibit B-1, Chapter 3, Resource Options, Section 3.5.1, Cost of Capital, p. 3-42

As part of the BCTC ILM CPCN Proceeding, in response to BCUC IR 3.216.3 (Exhibit B1-12 in that Proceeding), BC Hydro filed examples of estimated changes in debt and (Deemed and GAAP) equity levels over time under different scenarios for future annual capital expenditures. Please re-file this evidence in this proceeding.

61.1 Please provide a detailed explanation of the derivation of the debt and equity levels and file the spreadsheets used to produce the tables filed with BC Hydro's response to BCUC IR 3.216.3.

61.2 In the tables that accompany BC Hydro's response to BCUC IR 3.216.3, in some scenarios the sum of BC Hydro's debt and deemed equity (for rate setting purposes) is greater than the sum of BC Hydro's debt and GAAP equity. Please explain why a WACC based on 80% debt and 20% equity would not be more appropriate given the results in the tables filed by BC Hydro.

62.0 Reference: Directive Concordance

62.1 Please prepare a concordance table for the directives contained in the 2006 IEP/LTAP decision.

63.0 Reference: Biomass ROU
Exhibit B-1, Section 3.3.3., Methodology, p. 3-15
Woodwaste

63.1 When will the new guidelines being developed by the B.C. Ministry of Forests and Range be available? Please file a copy when it becomes available.

64.0 Reference: Biomass ROU
Exhibit B-1, Section 3.3.3.1, Table 3-12
MSW

64.1 Page 3-15 of the Application states that MSW data consist of three proposed projects. Please reconcile this statement with the one MSW project shown in Table 3-12.

65.0 Reference Site C ROU
Exhibit B-1, Section 3.3.9.2, Site C Stage 1 Report Costs, Table 3-19

65.1 Does OIC 787 (Appendix L3) affect the analysis in Table 3-19? Please provide an update if there are changes.

66.0 Reference: Greenhouse Gas Offset Price Forecast
Exhibit B-1, Section 4.2.1, Introduction, p. 4-2

"The 2006 IEP/LTAP recognized the potential for government-imposed costs associated with GHG policy. In the intervening two years, the B.C. Government and a number of U.S. states have implemented mandatory targets for GHG reduction. The Canadian Federal Government is currently in the process of introducing regulations under the *Canadian Environmental Protection Act* (**CEPA**) to set mandatory GHG reduction targets and the U.S. Congress also plans to legislate GHG reduction goals. These legislative initiatives are expected to establish and influence the market price for GHGs through such regulatory mechanisms as emissions trading and GHG offset programs."

66.1 In order to put into context the Natsource GHG price forecast, please provide information, in tabular and chart format, on the growth of GHG emissions (Megatonnes) in B.C. and Canada: (a) historically (1990 to 2007); and (b) projections of GHG emissions (Megatonnes) with and without emission reduction targets established by the respective Federal and Provincial regulatory policies (until 2050). Please list the government initiatives (e.g., March 2008 Regulatory Framework as indicated on p. 4-4; *GGRTA* on p. 4-5) used in the 'with targets' scenarios.

67.0 Reference: Greenhouse Gas Offset Price Forecast
Exhibit B-1, Section 4.2.2.2, Province of British Columbia pp. 4-4 – 4-7
B.C. Government Legislative Developments

67.1 The Province of British Columbia released on June 26, 2008 its Climate Action Plan. One of the main conclusions of the report is that the Province's climate action initiatives that are already announced would take British Columbia approximately 73% of the way to the Province's 33% 2020 reduction target. Please confirm that the climate action legislation as noted in the Climate Action Plan (and attached to this IR) has been considered in the 2008 LTAP.

Highlights

Reaching Our Target

Independent economic modelling estimates that the climate action initiatives announced since 2007 will take us approximately 73 per cent of the way to our 2020 33 per cent greenhouse gas reduction target.

The Climate Action Team will make recommendations at the end of July, 2008, for how to fill the remaining gap needed to reach our target. The Team will also recommend interim 2012 and 2016 targets, which must be set by law by the end of 2008.

The government has recently passed a number of significant pieces of climate-action legislation that define the British Columbia approach to reducing green-house gas emissions and preparing for the new low-carbon realities of the future. This legislation includes:

- **The Greenhouse Gas Reductions Targets Act, to set GHG reduction targets for the Province.**
- **The Greenhouse Gas Reduction (Cap and Trade) Act, to enable the implementation of a cap and trade system in conjunction with regional partners.**
- **The Greenhouse Gas Reduction (Vehicle Emissions Standards) Act, to enable the adoption of vehicle emissions standards that will increase automobile fuel efficiency.**
- **The Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, to regulate landfill gas.**
- **The 2008 Utilities Commission Amendment Act, to encourage more low-carbon energy generation projects.**
- **The Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act, to encourage the development of renewable forms of energy and decrease the carbon content of fuels.**
- **The Local Government (Green Communities) Statutes Amendment Act, 2008, to encourage the development of more sustainable, healthy communities.**
- **The Carbon Tax Act, to encourage low-carbon economic development while reinvesting every penny of carbon tax revenue into targeted tax cuts for individuals and businesses.**

68.0 Reference: Greenhouse Gas Offset Price Forecast
Exhibit B-1, Section 4.2.2.2, Province of British Columbia, p. 4-7

68.1 Page 4-7 mentions that for the Province's forthcoming climate change legislative and regulatory program to be harmonized with the Canadian Federal Government's GHG policies and Regulatory Framework, it will need to enter into an equivalency agreement with the Government of Canada. Please explain in detail what an equivalency agreement is and the timeframe for the development of such an agreement.

69.0 Reference: Greenhouse Gas Offset Price Forecast
Exhibit B-1, Section 4.2.2.3, U.S. – Federal Government and State Initiatives

The evolving interrelationship between the GHG policies of Canada and the U.S. at the Federal level is expected to significantly influence GHG prices faced by utilities in B.C. Attached is a press release on the Montreal Climate Exchange.

69.1 Is this Exchange a result of one of the Federal Government's intentions to establish a carbon emissions trading market (X-reference: Appendix G-1 page 7 of 79)?

69.2 Would the Federal level trading market preempt regional level (e.g., WCI/WECC) policies? Please comment on the Montreal Climate Exchange market participants' activities to date and if the Exchange's activities would influence the GHG offset price in the WCI/WECC region.

THE MONTRÉAL CLIMATE EXCHANGE IS ESTABLISHED

A partnership between
the Montréal Exchange and the Chicago Climate Exchange®

July 12th 2006 (Montréal and Chicago) – The Montréal Exchange (MX) and the Chicago Climate Exchange (CCX®) announced today the establishment of the Montréal Climate Exchange (MCeX), the first environmental products market in Canada. The new exchange combines the special expertise of the MX, Canada's financial derivatives exchange, with that of CCX, which operates the only global greenhouse gas emissions trading system. CCX is a world leader in building and operating environmental markets.

The two exchanges have finalized the preliminary agreement announced in Montréal on December 7 2005, during the landmark 1st meeting of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC, MOP-1).

"The Montréal Climate Exchange will accelerate the development of a structured environmental market in Canada," said Mr. Luc Bertrand, President and CEO of MX. "Since our first announcement, last December, we have received a multitude of requests for information. There is no doubt that people are interested. The Canadian industrial and financial communities are ready to welcome market-based solutions, and the Montréal Climate Exchange will provide those solutions."

MX will bring to the new climate exchange its expertise in leading-edge trading systems, clearing, market regulation and financial risk management. CCX will contribute its experience in operating the Chicago Climate Exchange, the first and only exchange of its kind in North America and now the second largest live market in the world, as well as its subsidiary, the European Climate Exchange (ECX), now the largest exchange operating in the European Union emissions trading system. The Chicago Climate Exchange, and its founder Dr. Richard L. Sandor, are widely recognized as pioneers in the field of financial innovation and in development of emissions trading and other environmental financial products.

"Establishing the Montréal Climate Exchange will place Canada in a strong position to confront environmental challenges in a cost-effective market-based manner. MCeX is a significant advance in the global integration and expansion of environmental markets," said Dr. Richard L. Sandor, Chairman and CEO of CCX. "This new Exchange will combine the environmental and financial expertise of Chicago and Montréal to offer an attractive suite of environmental financial products and services to the Canadian market."

The mission of the Montréal Climate Exchange is to offer price transparency, environmental integrity, low cost, wide access and reliability to the many sectors of the Canadian economy involved in air quality and climate change concerns.

Mr. Bertrand pointed out that the Montréal Climate Exchange looks forward to emerging plans in Canada with regard to greenhouse gas emissions reduction, including the federal Government plan, expected in the fall. In this regard, he noted: "We are confident that our approach offers the wide flexibility and quality required to advance a variety of ideas and regulatory frameworks. Our partner, CCX, has already developed systems that operate in the disparate regulatory environments of the US and Europe. We feel we are well prepared to help develop a uniquely Canadian approach to benefit Canada as a nation and the world generally."

70.0 Reference: Greenhouse Gas Offset Price Forecast
Exhibit B-1, Section 4.2.3.1, Economic Modelling Activity Subsequent to the Natsource Report
Exhibit B-1-1, Appendix G1, p. 31-79 Likelihood of Different Scenarios

The analysis released by the Federal Government on March 10, 2008 provided estimates of prices on credits from $25/tonne in 2010-2012 and rising to $65/tonne in 2018-2020.

70.1 If the estimates from this Federal Government Economic Model were added as a fourth planning scenario in addition to (1) Price Cap, (2) Linked Market and (3) Made in North America Aggressive Targets, what would be the respective probabilities for these four planning scenarios?

71.0 Reference: Greenhouse Gas Offset Price Forecast
Exhibit B-1-1, Appendix G1, Table 6 Sensitivity Analysis

On page 31 of 79 of the Natsource report, the Price Cap Scenario was considered to be less likely than the Linked Markets scenario and the Made in North America-Aggressive Targets scenario. The Price Cap Scenario is given a 15% probability in the Application. On page 34 of 79 of the Natsource report, the "BC compliance instruments only" case is considered unlikely in view of the very high costs associated with meeting the BC target while limiting eligible offsets to those generated in BC.

71.1 Table 6 provides a range as well as the mid-point for the three "BC compliance instruments only" scenarios and the range and mid-point for the WCI/WECC Price Cap scenario. Please comment how useful the figures in Table 6 are considering that they are with respect to unlikely cases.

72.0 Reference: Greenhouse Gas Offset Price Forecast
Exhibit B-1-1, Appendix G2, Carbon Tax in British Columbia

72.1 Please provide the current CO_2 equivalent emissions as well as their respective percentage shares from all fossil fuels that form the carbon tax base.

72.1.1 Please provide the percentage share of estimated carbon tax revenue.

72.2 Please provide the percentage shares of fossil fuels and industrial processes' contributions to British Columbia' total current GHG emissions.

72.3 To the best of BC Hydro's knowledge, how many jurisdictions in North America are contemplating, or have in force, both carbon tax and cap-and-trade mechanisms to reduce greenhouse gas emissions.

73.0 Reference: GHG Price Forecast
Exhibit B-1, Chapter 4, Market Assessment, Section 4.2.3, GHG Price Forecast, p. 4-10

73.1 Please prepare a table that converts the cost in $ per tonne to cents per kW.h for GHG prices ranging from $10 to $100 in increments of $10 for a natural gas generator with efficiencies ranging from 30% to 80% in increments of 10%

74.0 Reference: Natural Gas Price Forecast
Exhibit B-1, Chapter 4, Market Assessment, Section 4.3.1, Global Energy Forecasts, pp. 15-16

74.1 Please provide all documents produced regarding the "structured review" described at line 20.

74.2 Please explain the "points of inflection" shown on Figure 4-2 (1) in 2009 for the low and high forecast (2) in about 2019 for the high forecast and (3) about 2016 for the mid forecast.

75.0 Reference: Natural Gas Price Forecast
Exhibit B-1, Chapter 4.0, Market Assessment, Section 4.3, Natural Gas Price Forecasts, p. 4-15
Global Energy Forecasts

It states that: "Following a structured review, Global Energy assigned probabilities to its three natural gas forecasts as follows: 1B (Base – 44 percent; 2 (High) – 53 per cent; and 5BPlus (Low) – 3 per cent."

75.1 It appears from the information presented there is little confidence placed in the "low case" forecast. In fact, it appears that only one forecast has a probability of greater than 50%. In BC Hydro's view, does this suggest that all forecasts should be redone with more current information?

76.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 1, Introduction, p. 6
Global Energy Forecasts

It states that: "The relative geographic position, and shear size and influence of the California economy and its utilities allow the CEC forecasts to form a logical basis for the extrapolation to the Province of British Columbia."

76.1 Does an extrapolation of this degree assume that there is unlimited capacity in the major pipelines transporting gas to markets in British Columbia, the Pacific Northwest and California? In this case, have the particular operating characteristics of the Westcoast pipeline and Northwest Pipeline Inc. been taken into account?

76.2 A number of pipelines are being constructed to increase capacity to trapped Rockies gas, has this been taken into account?

77.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 1, Introduction, p. 10
Global Energy Forecasts

77.1 It states that: "For the CEC Scenarios Analysis Project, Global Energy modeling developed Henry Hub prices in constant 2006 U.S. dollars for the years 2009 – 2020."

77.2 Why were Henry Hub futures prices used instead of AECO prices?

78.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 3.2, Base Case Price Forecast for the CEC Scenario Analysis Project (Forecast 1) "Current Conditions Extended into Future", p. 12

It states that: "Part of the update requested by the CEC was to use more recent NYMEX Henry Hub futures in the early years of the forecast."

78.1 Should the current forecast be updated with more recent NYMEX Henry Hub futures natural gas prices considering the current state of prices in the crude oil and natural gas markets?

79.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 3.2, Base Case Price Forecast for the CEC Scenario Analysis Project (Forecast 1) "Current Conditions Extended into Future", p. 12

79.1 Gas fired electricity generation plants that are planned to be built in the Pacific Northwest would have an impact on the sustained natural price forecast so the resource plans of the various utilities would have to be incorporated into the scenarios. Have the most recent resource plans of the various utilities been incorporated into the resource build out assumptions in the base case?

80.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 3.3, High Gas Price Forecasts for the CEC Scenario Analysis Project (Forecast 2-High) "High sustained Natural Gas Prices", p. 17

It states that: "The parameters selected for the High Gas Price forecast were based on Global Energy's estimate of sustainable oil prices for its base, high and low case prices. The generalized ranges for Global Energy's oil price forecasts were at the time (Fourth Quarter, 2006 – First Quarter, 2007):

High: $60 - $70/bbl ($65/bbl midpoint)

Base: $45 - $55/bbl ($50/bbl midpoint)

Low: $30 - $40/bbl ($35/bbl midpoint)

80.1 The current dynamic in the oil market may indicate that current prices are indicative of a long term trend to the high case being sustainable. What is your present forecast for oil prices under a high, base and low pricing scenario?

81.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 3.3, High Gas Price Forecasts for the CEC Scenario Analysis Project (Forecast 2-High) "High sustained Natural Gas Prices", p. 18

81.1 What is the average NYMEX oil to Henry Hub natural gas price ratios per year over the last ten years? Would these ratios have any relevance on which to develop a base forecast?

The forecast report states that: "Non-fundamental oil parameters also included were OPEC's cartel pricing providing scarcity and security bid adders (premiums) of approximately $15/bbl, and related non-commercial (speculative) trading premium at approximately $5/bbl."

81.2 How were these premiums determined? With oil at current levels have these premiums changed?

82.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 3.4, Low Gas Price Forecast for the CEC Scenario Analysis Project (Forecast 5BPlus-Low) "High Energy Efficiency and Renewables Throughout the West and Lower Gas Prices Including Production Curtailment",
p. 21

The forecast report states that: "Global Energy recommended to BC Hydro that it utilize the CEC low Price Forecast as one scenario in preparation of the 2008 LTAP."

82.1 Is this still Global Energy's position?

83.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 4.0, Comparison to More Recent Gas Price Forecasts, p. 27

The Base Case Price Forecast along with the High and Low Forecasts were made a year ago. Global Energy then compared the three CEC Henry Hub gas price forecasts with the NEB forecasts, EIA AEO forecasts (made January 2008) and Global Energy's independent forecast for Henry Hub gas prices completed in the fall of 2007.

83.1 Does this comparison still have significance in your view? Have any of these forecasts been updated and if so what is the result of that comparison?

84.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 5.0, Probabilities of Three Gas Price Forecasts, Section 5.4, Conclusions, p. 32.

84.1 The forecast report concludes that it was reasonable for BC Hydro to use the three CEC gas price scenarios, and their estimated probabilities, in developing its 2008 LTAP. Is this statement still valid today?

85.0 Reference: Natural Gas Price Forecast
Exhibit B-1-1, Appendix I, Global Energy Natural Gas Price Forecast, Section 5.0, Probabilities of Three Gas Price Forecasts, Section 5.5, Major Factors in the Probability Assessment, p. 33.

It states that: "High oil prices are one of the primary reasons why Global Energy's assessment of probabilities of the High versus Base forecast changed during 2007 and early 2008, making out assessment in favour of the High Case more likely."

85.1 In your view has the probability of the high case changed or should the high case be redone entirely?

86.0 Reference: Electricity Price Forecast
Exhibit B-1, Section 4.4.1, General, p. 4-18, 22
Electricity and Natural Gas Markets

One of the more significant changes in U.S. markets since the 2006 IEP/LTAP is the increasing number of U.S. states that have passed RPS legislation (page 4-22); many RPS standards were originally established as a way of reducing dependence on natural gas fuel supplies that will increasingly need to be imported from areas outside of North America (Exhibit B-1-1, Appendix H, p. 10 of 47). Furthermore, BC Hydro has decided that the potential benefits natural gas-fired generation brings are outweighed by the potential costs in the Clean Power Call process (X-reference: Exhibit B-1 p. 6-33).

86.1 Please put into context the assertion that WECC's electricity and natural gas markets have become closely inter-related since natural gas has become the predominant fuel for new electricity generation. Does BC Hydro believe that natural gas will continue to remain the predominant fuel for new electricity generation for the 2008 LTAP planning period?

87.0 Reference: Electricity Price Forecast
Exhibit B-1, Chapter 4, Market Assessment Section 4.4.1, General, p. 4-18

87.1 Why is it appropriate to use an hourly model to calculate prices for 20 years as described beginning at line 11?

88.0 Reference: Electricity Price Forecast
Exhibit B-1, Chapter 4, Market Assessment Section 4.4.3,
2008 Electricity Price Forecast, p. 4-21

88.1 Please provide the data behind Figures 4-5 and 4-6 in tabular form.

88.2 Please prepare a graph which combines Figure 4-6 and Figure 4-2.

89.0 Reference: Electricity Price Forecast
Exhibit B-1, Section 4.4.2, Incorporation of GHG Price Forecast, p. 4-20

The Application states that 360 tonnes CO_2e/GWh is the GHG intensity of a new, efficient CCGT.

89.1 Is the performance standard of 360 tonnes fixed for the next 20 years? If so, please explain why no technological improvement assumption is built in. If not, please provide the emerging standard.

90.0 Reference: Market Assessment for Clean or Renewable Electricity
Exhibit B-1-1, Appendix H, p. 6 of 47 Renewable Energy Credits
Exhibit B-1, Table 4-3 Out-of-country Renewable Energy Products

Global Energy concludes that most WECC state RPS legislation allows out-of-country renewable electricity products, with some states being more restrictive than others.

90.1 Please confirm that SD 10 criterion for self-sufficiency does not allow out-of-country renewable products for British Columbia. If confirmed, please describe if those states in Table 4-3 that have 'no restrictions' in importing renewable electricity products apply to jurisdictions that do not grant reciprocity.

91.0 Reference: Market Assessment for Clean or Renewable Electricity
Exhibit B-1, Table 4-4 REC Prices

Renewable Energy Credits ("RECs") are created by separating the attributes of renewable electricity generation from the physical electricity produced, thus making RECs a tradable commodity separate from the actual electrons. RECs may be "bundled" together with their associated electricity that is produced at the renewable electricity generation facility (Exhibit B-1-1, Appendix H, p. 8 of 47).

91.1 For those high and low figures (2007 US$/MWh) in Table 4-4, what would be the "bundled" amount?

92.0 Reference: Market Assessment for Clean or Renewable Energy
Exhibit B-1, Chapter 4, Market Assessment, Section 4.5.2
Use of Global Energy Analysis in 2008 LTAP Analysis, p. 4-25

BC Hydro states the portfolio analysis in Chapter 5 includes the estimated incremental revenue that would result from the sale of the clean or renewable electricity from the BC Hydro system.

92.1 Please explain whether BC Hydro assumes the sale of unbundled RECs from generation in BC that is not physically exported and, if so, whether the sale of these unbundled attributes is consistent with clean energy targets for energy consumed within the province.

92.2 Please provide examples of the detailed methodology and assumptions for estimating incremental revenues from the sale of unbundled RECs for two or three portfolios modelled by BC Hydro, including the amount of RECs sold for the portfolio, the calculation of revenue from the sale of RECs, and the treatment of the revenue in the portfolio analysis.

93.0 Reference: Risk Framework
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.2.2
Quantifying Uncertainty, p. 5-9

93.1 BC Hydro states: "Hydrology and spot market prices for gas and electricity are also key uncertainties for BC Hydro. These were incorporated into the planning criteria and portfolio modelling process rather than being incorporated explicitly into the quantitative portion of the Risk Framework." Please summarize how these uncertainties were incorporated into the planning criteria and portfolio modelling process.

94.0 Reference: Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.3.3
Natural Gas Plant Modelling, pp. 5-16 to 5-21

BC Hydro states: "As a result of Policy Actions No. 18 and 19 and the *Emissions Standards Act*, all natural gas fired generation will be required to offset 100 per cent of their GHG emissions (existing plants by 2016 and new natural gas plants immediately). In addition, as described in section 4.2.2.2, BC Hydro has assumed for purposes of the 2008 LTAP that all natural gas-fired generation will be required to pay the carbon tax on natural gas usage established in the 2008 Provincial Budget and by the *Carbon Tax Act*."

94.1 Please explain BC Hydro's rationale for assuming thermal generation would be subject to both offset AND carbon tax requirements. Has this been clearly established by government? Please explain particularly in light of the following comment in Section 4.2.2.2 of the Application: "Pursuant to section 84 of the *Carbon Tax Act*, the B.C. Cabinet may with respect to a fuel or combustible that is the source of GHG emissions, provide for a regulation that exempts from the payment of the tax, or that refunds of all or part of the tax paid, subject to compliance obligations under the *Carbon Tax Act* and the new offset requirements for electricity generation under the *Emissions Standards Act*.

94.2 Please provide examples of other sectors in B.C. that are expected to be subject to both offset (or cap and trade) requirements AND a carbon tax.

94.3 Please provide examples of other jurisdictions that both require full offsets AND tax emissions for thermal generation.

94.4 Please explain the derivation of the market heat rates in Figures 5-3 through 5-6 with specific examples of the calculations.

94.5 Please reproduce Figures 5-3 through 5-6 assuming thermal generation in B.C. is only subjected to one of the Carbon Tax or offset requirements, similar to jurisdictions outside B.C.

95.0 Reference: Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.3.3 Natural Gas Plant Modelling, pp. 5-16 to 5-21

BC Hydro states: "New natural gas plants had a minimum dispatch requirement to reflect the intent of self sufficiency in that they would need to be capable of running, including on an economic basis, if required. If the plants were never intended to run, they would never be built." BC Hydro then establishes minimum operating factors for SSGTs and CCGTS.

95.1 Please explain if/how BC Hydro's approach to modelling of natural gas plants accounts for the real option value of these plants over and above their expected value – that is the additional value of the flexibility these types of plants offer in the face of volatile hydro output and market prices.

95.2 If SSGTs or CCGTs were curtailed in favour of non-firm energy available from IPPs in B.C., would that be consistent with SD10 in BC Hydro's view and would that alter the treatment of these plants in the portfolio analysis?

96.0 Reference: Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.3.6 Resource Portfolios, p. 5-23

96.1 Please illustrate the effect of the minimum operating factors for gas generation on the portfolio construction and analysis for the Base 11 Scenarios in the Portfolio Analysis. Please reproduce Table 5-5 for the base 11 portfolios with new assumptions as follows:

96.1.1 Continue to assume the minimum operating factors for SSGTs and CCGTs but include only the GHG offset requirement for BC-based thermal generation (i.e., do not also include the carbon tax).

96.1.2 Eliminate the minimum operating factor constraints for SSGTs and CCGTs and include only the GHG offset requirement for BC-based thermal generation (i.e., do not also include the carbon tax). For each portfolio / scenario please include an indicator of the actual expected dispatch of thermal plants in B.C. (including the offset requirement but excluding the carbon tax) under (a) critical water conditions, (b) average water conditions, and (c) 80th percentile water conditions, and (d) 90th percentile water conditions. For each scenario please also include an indicator of what percentage of domestic energy is supplied by imports (versus firm and non-firm domestic energy).

97.0 Reference: Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.3.3 Natural Gas Plant Modelling, pp. 5-16 to 5-21

97.1 Please explain the treatment of natural gas-fired cogeneration in the Portfolio Analysis (i.e., minimum operating constraints, GHG offset requirements and GHG taxes).

98.0 Reference: Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.3.4 Clean Electricity Target, p. 5-21

BC Hydro states: "The 2007 Energy Plan Policy Action 21 (see Table 1-2) commits to 'ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation". Further, the 2007 Energy Plan states that 'Currently in B.C., 90 per cent of electricity is from clean or renewable resources.' BC Hydro understands this target to be based on actual generation output in which 90 per cent of the electricity actually generated in B.C. would be from clean or renewable resources and that market sales would not be netted against actual generation regardless of whether B.C. is a net importer or exporter. In this LTAP, it is assumed that the Provincial target of 90 per cent would apply to BC Hydro, and that BC Hydro would meet the 90 per cent target with its own portfolio of resources."

98.1 Please explain what BC Hydro means by "market sales would not be netted against actual generation regardless of whether B.C. is a net importer or exporter."

98.2 Does BC Hydro include any revenues from the sale of unbundled RECs from generation consumed in the province (and included in the estimate of this target) within its portfolio modeling or only the RECs associated with net exports?

98.3 Does BC Hydro consider this target also to apply to the 3,000 GW.h of insurance and would BC Hydro therefore be excluded from the sale of RECs associated with the export of any of that insurance?

99.0 Reference: Burrard Generating Station Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.4.2.2 RWDI Study – Maintain Burrard, pp. 5-32 to 5-34

99.1 Have BC Hydro or its consultants conducted any formal public opinion research or focus groups with the general public and/or opinion leaders concerning the various scenarios outlined by BC Hydro for Burrard operation?

99.2 Has any of this research examined the effect of information regarding the actual operation, role, value, and impact of the plant on opinions?

100.0 Reference: Burrard Generating Station Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.4.2.2
RWDI Study – Maintain Burrard, pp. 5-32 to 5-34

100.1 BC Hydro states "A sensitivity analysis of the above portfolios that included the three scenarios of incremental prices for sales of RECs in the WECC (described in section 4.5) was completed on the above. Please explain the linkage of these portfolios to REC sales and provide a worked example for the calculation of the portfolio PV under one scenario of Burrard operation and REC prices.

101.0 Reference: Burrard Generating Station Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.4.3.1
Rebuild Burrard - AMEC, Figures 5-10 and 5-11, pp. 5-37 to 5-42

101.1 BC Hydro's analysis seems to suggest that CCGTs have a lower cost of capacity than SCGTs at virtually all capacity factors. Please reconcile these results with the following statement on p. 5-20 of the Application: "CCGTs are more capital intensive and therefore are expected to operate at higher capacity factors than SCGTs. For a base load CCGT type gas plant, the facility would only be built if there was an expectation that it would operate on a consistent basis with a relatively high average capacity factor. If a plant was expected to operate infrequently, one would instead rely on a SCGT type peaking plant. While SCGTs are low efficiency, they are capable of long term sustained dispatch and could be counted on for high capacity factor operation. The economic result in the perfect foresight modelling world is to commit SCGTs in preference to CCGTs even in high capacity factor energy requirement cases, knowing that the unit will be displaced with market purchases and never run."

101.2 Are SCGTs being built or planned currently anywhere else in the WECC?

102.0 Reference: Burrard Generating Station Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.4.2.3
Maintain Burrard - Analysis, Table 5-8, p. 5-36

102.1 For each scenario of the firm energy contribution from Burrard and the cost of thermal energy in Table 5-8, please provide a frequency distribution of the actual expected operation of Burrard (i.e., the number of years actual operation of Burrard up to the assumed firm energy contribution). In each case please also include an estimate of the percentage of Burrard's firm energy contribution that would come from net imports versus secondary (non-firm) energy from BC Hydro and IPP facilities within B.C.

102.2 Please provide a new version of table 5-8 (together with the frequency analysis requested above) assuming only the offset requirement for Burrard and excluding the carbon tax.

103.0 Reference: DSM Portfolio and Risk Analysis
Exhibit B-1, Section 5.5.4, DSM Deliverability Risk, Table 5-19 Average Annual DSM Energy Savings as a Percentage of Sales

103.1 Please add two additional columns to Table 5-19 to present the energy price for Residential and Commercial customers receiving services from those utilities.

104.0 Reference: DSM Portfolio and Risk Analysis
Exhibit B-1-1, Appendix F14, Risk Framework, Section 1.1.1, Eliciting Subjective Probability Estimates, pp. 4-5 of 29

104.1 Who were the experts BC Hydro consulted to elicit the different probability estimates reviewed in Appendix F14?

105.0 Reference: DSM Portfolio and Risk Analysis
Exhibit B-1, Appendix F14, Risk Framework, Section 1.1.7
Total DSM Savings, pp. 22-24 of 29

BC Hydro states: "It was assumed that the level of energy savings arising these three areas (Program, Codes and Standards, and Rate Structures) was independent from each other."

105.1 In response to BCUC IR 1.3.1 (Exhibit B-3 of the RIB proceeding), BC Hydro states that the RIB rate will act as a catalyst for increased participation in Power Smart programs. Does the assumption of independence contradict the statement made in the RIB proceeding?

105.2 Please provide further rational for this assumption and please explain how BC Hydro minimize the possibility of double counting of savings between programs, codes and rate structures in the analysis of total DSM savings.

105.3 Please explain in more detail how a larger DSM effort (with the same level of supporting initiatives) could result in a higher probability of lower savings than a smaller effort.

105.4 Please also explain the relationship between the statement above and the higher savings assumed under the low scenario for the aggressive DSM option in Table F14-4.

106.0 Reference: DSM Portfolio and Risk Analysis
Exhibit B-1, Appendix F14, Risk Framework, Section 1.1.8
DSM Programs and Capacity Savings, pp. 25-27 of 29

106.1 Why was no capacity analysis undertaken for Option B?

107.0 Reference: Clean Power Call Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.6.3
Optimum Sequence Analysis, p. 5-62

BC Hydro states: "The probability tree analysis also shows that clean resources are selected in all situations at some time through the planning horizon, while gas-fired generation is being selected only in the low to mid thermal (natural gas and GHG offset) cost scenarios, as well as in the high gap scenarios. As can be seen in the mid-gap cases, the most probable scenario is the high gas/mid GHG case and thermal was not picked up. This demonstrates that if the world unfolded as per our most probable scenario, gas would not be economic."

107.1 Please provide the comparable analysis assuming (a) minimum operating constraints for natural gas plants and only the cost of offsets (i.e., excluding the carbon tax); and (b) no minimum operating constraints for natural gas plants and only the cost of offsets (i.e., excluding the carbon tax).

108.0 Reference: Clean Power Call Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.6.3 Optimum Sequence Analysis, p. 5-62

BC Hydro states: "The relative economics of the 11 portfolios are presented in Table 5-24. This table presents the economics first without including any possible revenue from future REC sales, followed by the economics assuming REC sales revenue based on the low, mid and high REC price scenarios that were identified in section 4.5."

108.1 Please explain how the volume of available RECs in each portfolio is determined.

109.0 Reference: Clean Power Call Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.6.4, Call Commitment Analysis, p. 5-62

109.1 Given the inclusion of high-efficiency gas-fired co-gen in the definition of clean for the purposes of the SOP, does BC Hydro consider high-efficiency co-gen should be included in the definition of the clean call block. Why or why not?

110.0 Reference: Additional Modelling Considerations
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.9.1 Exchange Rate, pp. 5-78 to 5-80

BC Hydro states: "The results indicate that there is no swing in the selection of thermal resources through 2016 and no material swings in the types of resources being selected overall. For example, natural gas-fired generation (thermal) was not selected in any of the high gas cost scenarios (high or mid GHG offset costs). There are some small shifts in the amount of thermal and clean resources selected in the low and mid natural gas cost scenarios as the exchange rate changes, however, they are immaterial."

110.1 Please reproduce Tables 5-37, 5-38 and 5-39 assuming (a) the same minimum operating constraints for thermal generation but only including GHG offset costs (i.e., excluding the carbon tax) in the cost of thermal generation in B.C.; and (b) removing the minimum operating constraints for thermal generation and only including GHG offset costs (i.e., excluding the carbon tax) in the cost of thermal generation in B.C.

111.0 Reference: Additional Modelling Considerations
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.9.2 Cost of Capital and Discount Rate, pp. 5-81 to 5-83

BC Hydro states: "The results show that the higher cost of capital had a greater impact on the PV costs as the cost of thermal increases. This is generally because the cost of capital impacts the cost of clean resources (relatively higher capital, lower operating costs) more than gas-fired resources (relatively lower capital costs, higher operating costs). Changing the discount rate and cost of capital showed the same relative impact as cost of capital changes, but the overall numbers were reduced due to the higher discount rate used. However, overall the relative content and ranking of portfolios did not materially change.

111.1 Please reproduce Tables 5-40 through 5-43 assuming (a) the same minimum operating constraints for thermal generation but only including GHG offset costs (i.e., excluding the carbon tax) in the cost of thermal generation in B.C.; and (b) removing the minimum operating constraints for thermal generation and only including GHG offset costs (i.e., excluding the carbon tax) in the cost of thermal generation in B.C.

112.0 Reference: Additional Modelling Considerations
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.9.4 Long Portfolio Impacts / Exposure to External Markets, pp. 5-85 to 5-96

112.1 How has BC Hydro addressed the government's targets for an insurance of 3,000 GW.h in the portfolio analysis?

113.0 Reference: Additional Modelling Considerations
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.9.4 Long Portfolio Impacts / Exposure to External Markets, Table 5-46, p. 5-86

113.1 Does the column labeled "lowest" net exports correspond to net exports under critical water conditions? Why is this number positive in so many scenarios given the portfolios are created to meet firm energy requirements? Does this reflect the amount of non-firm IPP energy acquired with firm energy?

113.2 Please reproduce Tables 5-46 assuming (a) the same minimum operating constraints for thermal generation but only including GHG offset costs (i.e., excluding the carbon tax) in the cost of thermal generation in B.C.; and (b) removing the minimum operating constraints for thermal generation and only including GHG offset costs (i.e., excluding the carbon tax) in the cost of thermal generation in B.C.

114.0 Reference: Additional Modelling Considerations
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.9.4 Long Portfolio Impacts / Exposure to External Markets, Figure 5-20, p. 5-91

114.1 What year does this analysis reflect?

114.2 Please provide a comparable figure for the non-Heritage hydro non-firm energy (i.e., non firm energy from IPPs) in the same year.

115.0 Reference: DSM Plan and LTAP Action Item
Exhibit B-1, Chapter 6, Section 6.2.1.1, Orders Sought, p. 6-2; Appendix K, pp. 101-114 of 213, & BC Hydro F09-F10 RRA, Exhibit B-10, Evidentiary Update

In the 2008 LTAP BC Hydro states that it is applying for a BCUC Order "that the amortization period for deferral DSM expenditures should remain at ten years."

115.1 The following table was extracted from the BC Hydro F2009 and F2010 Revenue Requirements Application ("RRA"), Evidentiary Update (Exhibit B-10, Regulatory Model, Schedule 2.2, p. 6). Please complete the following table with the DSM amortization of both the opening balance and the F2009 and F2010 additions over ten years and alternatively over time periods of five to nine years.

	10 Year Amort		9 Year Amort		8 Year Amort		7 Year Amort		6 Year Amort		5 Year Amort	
	F2009	F2010	F2009	F2010	F2009	F2010	F2009	F2010	F2009	F2010	F2009	F2010
Demand-Side Management												
Beginning of Year	309.3	379.8	309.3	379.8	309.3	379.8	309.3	379.8	309.3	379.8	309.3	379.8
Additions	112.1	138.2	112.1	138.2	112.1	138.2	112.1	138.2	112.1	138.2	112.1	138.2
Amortization on Existing	(36.0)	(34.4)										
Amortization on Additions	(5.6)	(18.1)										
End of Year	379.8	465.5										
Carrying Cost on Mid-Year Balance												
Debt												
Equity												
Total Carrying Cost												
Rate Impact of Amortization and Carrying Cost												

115.2 Please complete the preceding table where the DSM amortization of the opening balance is over ten years while the amortization of the F2009 and F2010 additions are alternatively over five to ten years.

115.3 Please reconcile the F2009 and F2010 DSM activities in Appendix K of BC Hydro's 2008 LTAP and the F2009 and F2010 DSM additions and amortization shown in the BC Hydro F2009 and F2010 RRA, Evidentiary Update, Exhibit B-10, Regulatory Model, Schedule 2.2, page 6.

115.4 It appears that the DSM regulatory account has grown in recent years, for example, from $282.1 million (Actual F2007) to $465.5 million (F2010 Update). At what year and by what amount does BC Hydro estimate the DSM account will reach a steady state or peak? Please provide a best estimate. If needed, state the assumptions.

115.5 How does BC Hydro propose to manage the DSM account balance to mitigate its continued growth?

115.6 Deferral of DSM expenditures reduces the current period's revenue requirements and results in ratepayers not seeing a significant rate impact. Since a DSM program's objective is to conserve energy, would it be better to flow more current expenditures into rates thus providing a price signal to achieve energy conservation?

116.0 Reference: Portfolio Analysis
Exhibit B-1 Chapter 5, Risk Framework and Portfolio Analysis, Section 5.3.3 Natural Gas Plant Modelling, pp. 5-20, 21

116.1 Does the System Optimizer ("SO") contain a constraint regarding self-sufficiency? If yes, please describe.

116.2 How were the minimum operating factors chosen?

117.0 Reference: Burrard Generating Station Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.4
Burrard Generating Station, p. 5-24

117.1 Beginning at line 4 BC Hydro states "While the current expected in-service date of 5L83 is October 2014, BC Hydro is developing its contingency plans to manage up to a five-year delay. Therefore, BC Hydro's current plan is that Burrard must be capable of reliably providing its capacity and energy capability at least through 2019." Does this mean that BC Hydro is planning to the contingency (CRP) rather than the base?

118.0 Reference: Burrard Generating Station Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.4.3.1
Rebuild Burrard – AMEC, p. 5-40

118.1 CO_2 emissions have been given a range of prices. Is it possible to make a similar analysis for NOX?

119.0 Reference: DSM Portfolio and Risk Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.5, DSM p. 5-46

119.1 Why was DSM with even high savings not investigated as an option (though it might subsequently be discarded)?

120.0 Reference: DSM Portfolio and Risk Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.5.3
Economic Analysis, p. 5-51

120.1 Please provide Table 5-14 and 5-15 for Option B.

121.0 Reference: Site C Portfolio Analysis
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.8
Site C, p. 5-77

121.1 It states that Site C is attractive as a backup should some resources not materialize. How useful is a backup that has a minimum ten year lead time?

122.0 Reference: Additional Modeling Considerations
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.9.1
Exchange Rate, p. 5-79

122.1 BC Hydro states: "The results indicate that there is no swing in the selection of thermal resources through 2016 and no material swings in the types of resources being selected overall . For example, natural gas-fired generation (thermal) was not selected in any of the high gas cost scenarios (high or mid GHG offset costs). There are some small shifts in the amount of thermal and clean resources selected in the low and mid natural gas cost scenarios as the exchange rate changes, however, they are immaterial." Does this result hold if the tree is not truncated and all eleven branches are considered?

123.0 Reference: Additional Modelling Consideration – Long Portfolio Impacts
Exhibit B-1, Chapter 5, Risk Framework and Portfolio Analysis, Section 5.9.4
Long Portfolio Impacts / Exposure to External Markets, p. 5-88

123.1 Please provide, in graphical and tabular format, weekly mid-C prices for 2001 and 2007, or some other period that would support using the correlation derived in 2001/2002 with flow volumes at Dalles.

124.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1, Section 6.2.1, DSM Implementation Plan, p. 6-1
DSM Energy Savings in the 2006 LTAP

124.1 BC Hydro requested $1.7 million to undertake and complete the Definition phase work of EE3, EE4 and EE5 and to update the CPR, and the request was granted by Order No. G-29-07. Please describe the status of these Energy Efficiency programs and whether any of these programs are included in the updated DSM Plan.

125.0 Reference: Mica Unit 5 & 6 LTAP Action Items
Exhibit B-1, Section 6.2.4.2, Justification, p. 6-21

125.1 Table 6-10 shows that Regulatory approvals, First Nation Consultation and Stakeholder Engagement will total $9.5 million over the next two and a half years (Table 6-9). Please provide a breakdown of the $9.5 million by activity.

126.0 Reference: Site C LTAP Action Items
Exhibit B-1, Section 6.2.5.4, Future Approval Process and Expenditures, p.6-26

In the 2006 IEP/LTAP, an estimate was provided for Stage 2 costs, which at the time was predicted to be $20 million for F2007/F2008. Since then, Stage 2 has become significantly more defined, including incorporating more preliminary analysis to be better prepared for a potential future regulatory stage.

126.1 For each activity (as outlined in Table 6-11 on page 6-27) in Stage 2, please provide a comparison of the cost estimates made in the 2006 IEP/LTAP.

127.0 Reference: Site C LTAP Action Items
Exhibit B-1-1, Appendix L2, Section 5, Budget, p. 19 of 20

127.1 For each activity as outlined in the table entitled Estimated Stage 2 Spending by Task Group, please provide a breakdown of spending incurred by external consultants, internal BC Hydro staff and others.

128.0 Reference: Clean Power Call LTAP Action Items
Exhibit B-1, Section 6.2.6.2, Justification, p. 6-29
Attrition Allowance

128.1 Given the expected flexibility with a structured RFP over a CFT and the expected reduced risk of legal claims, should these be considered steps to minimize attrition? Should a lower than 30% attrition factor for the Clean Power Call be used?

129.0 Reference: Bioenergy and Future Calls
Exhibit B-1, Section 6.2.7.1, Execution

129.1 Has BC Hydro determined whether Phase II of the Bioenergy Call will be a CFT or a RFP? Please explain your answer.

130.0 Reference: Fort Nelson LTAP Action Plan
Exhibit B-1, Section 6.2.9, Fort Nelson
Transmission System Protection Schemes

130.1 Has BC Hydro ever curtailed load in B.C. because of the AESO transmission system protection schemes for the full FN/RB region? Please provide a list of timing and duration of curtailment, if any.

131.0 Reference: Base Resource Plan
Exhibit B-1, Section 6.3, Load/Resource Gap After Execution of 2008 LTAP
Tables 6-14 & 6-15

Table 6-14 on 2007 System Capacity Supply presents Existing and Committed Supply excluding Alcan 2007 EPA. Table 6-15 on 2007 System Energy Supply presents Existing and Committed Supply including Alcan 2007 EPA.

131.1 Please explain why BC Hydro treats the Alcan 2007 EPA differently when presenting capacity and energy for the system.

131.2 Please re-do Table 6-14 including the Alcan 2007 EPA.

132.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1, Chapter 6, Long Term Acquisition Plan, Section 6.2.1.2
Justification, pp. 6-4, 5

132.1 Please redo Table 6-5 showing RS and P as separate columns.

132.2 Please redo Table 6-5 showing RS and P as separate columns under Option B.

132.3 Please provide the calculation which verifies the statement on page 6-5 that "BC Hydro's expenditures in support of codes and standards are justified on the grounds that they are cost-effective if only one per cent of the DSM Plan's codes and standards savings are attributable to BC Hydro's efforts."

133.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1, Chapter 6, Long Term Acquisition Plan, Section 6.2.2.3
Execution and Risk Mitigation, p. 6-11

133.1 What is the current state of BC Hydro's information and assumptions as to how different levels of incentives impacts participation rates?

134.0 Reference: Mica Unit 5 and 6 LTAP Action Items
Exhibit B-1, Chapter 6, Long Term Acquisition Plan, Section 6.2.4.2
Justification, pp. 6-20 to 22

134.1 Will there be a CPCN application for the Mica units and if so, when?

134.2 As per p. 6-22 line 22, what is a "Determination application"?

135.0 Reference: Clean Power Call LTAP Action Items
Exhibit B-1, Chapter 6, Long Term Acquisition Plan, Section 6.2.6.2
Justification, pp. 6-28, 29

135.1 Please provide a page and line number reference for the following statement "The updated load resource analysis in sections 2.4 and 5.6.2 show an energy shortfall of approximately 3,200 GW.h in 2016 based on the Mid Load Forecast and after implementation of the proposed DSM Plan."

135.2 Since there are a finite number of IPP projects, is it not more reasonable to use the 48% attrition figure from the last call rather than a value based largely on the experience in other jurisdictions?

136.0 Reference: Clean Power Call LTAP Action Items
Exhibit B-1, Chapter 6, Long Term Acquisition Plan, Section 6.2.6.3
Execution and Risk Mitigation, pp. 6-36 to 40

136.1 Of the other jurisdictions analyzed what was the split between RFPs and CFTs where the requesting entity was a crown Corporation or a public entity, as opposed to a private body?

136.2 Why are not projects in Fort Nelson eligible?

136.3 Will there be a penalty for failure to deliver firm energy?

137.0 Reference: Fort Nelson LTAP Action Items
Exhibit B-1, Chapter 6, Long Term Acquisition Plan, Section 6.2.9
Fort Nelson, p. 6-47

137.1 Please define transmission must run (TMR).

138.0 Reference: Fort Nelson LTAP Action Items
Exhibit B-1, Chapter 6, Long Term Acquisition Plan, Section 6.2.9.2
Justification, p. 6-48

138.1 As stated at line 15, what event may occur by 2013 that would allow BC Hydro to stop relying on Alberta?

139.0 Reference: Base Resource Plan
Exhibit B-1 Chapter 6, Long Term Acquisition Plan, Section 6.3
Load/Resource Gap After Execution of 2008 LTAP, pp. 6- 50 to 54

139.1 Please provide Tables 6-14 and 6-15 as fully functioning spreadsheets.

139.2 Why do EE2, EE3, EE4, EE5 and LD2 not appear in the tables?

139.3 What is the status of the ILM project in Table 6-14, and what are the maximum transfers and one-hour thermal limits?

140.0 Reference: Contingency Plans
Exhibit B-1 Chapter 6, Long Term Acquisition Plan, Section 6.4.
CRP Contingency Plans, p. 6-58

140.1 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." (emphasis added)

Please elaborate on the above statement. Does BC Hydro expect BCTC to build to the CRP or build to the base LTAP?

141.0 Reference: Contingency Plans
Exhibit B-1 Chapter 6, Long Term Acquisition Plan, Section 6.4.2
CRP Contingency Plans, p. 6-59

141.1 In tabular format, please compare the assumptions underlying the CRPs in this LTAP and the 2006 LTAP.

142.0 Reference: Contingency Plans
Exhibit B-1 Chapter 6, Long Term Acquisition Plan, Section 6.4.3
Transmission Contingency Plans, p. 6-62

142.1 Please separate the line "2007 Mid Load Forecast LM/VI before DSM" into its components: sales by customer class, distribution losses, regional transmission losses, and bulk transmission losses.

143.0 Reference: Alignment with 2007 Energy Plan, *UCA* Amendments, and BCUC Decisions
Exhibit B-1-1, Appendix B2, SD 10, p. 4 of 5

143.1 Section 3(e) states that BC Hydro should exceed its requirements by at least 3,000 GWh ***as soon as practicable***. Does BC Hydro agree that the required excess is available sooner than proposed from the resource options? If so, why does BC Hydro not obtain the insurance earlier?

143.2 Webster's defines "practicable" as capable of being done, feasible. How does BC Hydro interpret the word?

144.0 Reference: Elasticity Analysis
Exhibit B-1-1, Appendix E, Direct Testimony of Dr. Ren Orans, p. 5 of 28

144.1 Please recalculate Table A3.6 Exhibit B-1-1 Appendix D assuming the long term elasticity found at Table 1.

145.0 Reference: Elasticity Analysis
Exhibit B-1-1, Appendix E, Direct Testimony of Dr. Ren Orans, p. 6 of 28

145.1 At line 9 it is stated that as long as BC Hydro's rates were not increasing, the magnitude of double counting was small. Does BC Hydro agree that for many years rates decreased in real term? If so, does this further reduce double counting and if so how?

145.2 If it is accepted that when rates are low its reasonable to assume that long term impacts mainly result from government actions and Power Smart, how useful is such an assumption if future electricity price increases are well above inflation?

146.0 Reference: Elasticity Analysis
Exhibit B-1-1, Appendix E, Direct Testimony of Dr. Ren Orans, p. 12 of 28

146.1 Please confirm that all elasticities used are assumptions and that no attempt was made to estimate price elasticity from B.C. specific data.

146.2 Using the CPI, please prepare a table showing the annual percentage change in the real price of BC Hydro electricity from (1) 1980 to 2005 (2) 1985 to 2005 (3) 1990 to 2005.

147.0 Reference: Elasticity Analysis
Exhibit B-1-1, Appendix E, Direct Testimony of Dr. Ren Orans, pp. 14-18 of 28

147.1 Please confirm that the studies cited in general show long run price elasticities that are about twice as high or more as short run elasticities and contrast this with the assumption of a flat elasticity.

147.2 Please explain why a high winter demand is relevant in selecting studies for comparison with BC Hydro.

147.3 Using the results from the previous IR on annual percentage change in real price, please define relatively low rates.

147.4 Is it possible to draw any conclusions regarding price elasticity from BC Hydro's experience with its two tier industrial rate? If so, what has BC Hydro concluded?

148.0 Reference: Elasticity Analysis
Exhibit B-1-1, Appendix E, Direct Testimony of Dr. Ren Orans, p. 21 of 28

148.1 Please provide relevant excerpts from, or links to, the Avista, PacifiCorp and DOE studies cited in footnotes 15 and 16.

149.0 Reference: Elasticity Analysis
Exhibit B-1-1, Appendix E, Direct Testimony of Dr. Ren Orans, pp. 22-22 of 28

149.1 Regarding sales response it is stated that Dr. Orans' assertion is reasonable under two assumptions, one of which is that there is more marginally priced energy at the Step 2 rate than the Step 1 rate. At line 16 of page 22 it states the assumption is reasonable under the two conditions identified. Please explain how the listed assumption is satisfied in this case.

150.0 Reference: Elasticity Analysis
Exhibit B-1-1, Appendix E, Direct Testimony of Dr. Ren Orans, p. 23 of 28

150.1 Please explain the use of the word "conservative" at line 7. What is the impact on the savings attributed to DSM which would result from a higher estimate of price elasticity?

151.0 Reference: Resource Options (General)
Exhibit B-1-1, Appendix F1, Resource Options Database (RODAT) Sheets, p. 155 of 216

151.1 If the annual Firm Energy of the wind bundle is unknown, how can it be selected by the SO model?

151.2 Why is there no estimate of impacted land?

152.0 Reference: Resource Options (General)
Exhibit B-1-1, Appendix F12, Effective Load Carrying Capability/Firm Energy Load Carrying Capability of Intermittent Resources, p. 5 of 17

152.1 Please compare the results in Table 1-1 and 1-2 to the results in the 2006 IEP/LTAP.

153.0 Reference: Resource Options (General)
Exhibit B-1-1, Appendix F1, Effective Load Carrying Capability/Firm Energy Load Carrying Capability of Intermittent Resources, p. 11 of 17

153.1 Please explain the basis for the ELCCs of 21% and 29%.

154.0 Reference: Resource Options (General)
Exhibit B-1-1, Appendix F15, Resource Planning Models, p. 4 of 8

154.1 Please provide the objective function and constraints used in the System Optimizer Model for a case that BC Hydro feels would be expository.

155.0 Reference: Resource Options (General)
Exhibit B-1-1 Appendix F16, Portfolios and Analysis, p. 2 of 233

155.1 Please confirm that all cash flows are incremental as stated at page 200 of the 2006 IEP/LTAP decision.

156.0 Reference: Resource Options (General)
Exhibit B-1-1, Appendix F16, Portfolios and Analysis

156.1 Please prepare a summary table indexed to the results shown at page 6 of 233 to 233 of 233 that includes the resources selected in the first 10 years of the forecast, both clean criteria, the PV (in 2011) and the DSM energy and capacity in 2020.

157.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, pp. 6-7 of 213

157.1 Please provide the detailed derivation of the figure of 13 cents per kW.h. Without performing a detailed analysis, please provide indicative savings by F2021 at values of 10 and 16 cents per kW.h. Please also provide capacity savings.

157.2 Please explain the term supportive market conditions as found on page 7.

158.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, p. 15 of 213

158.1 In BC Hydro's view, does a two tier rate actively encourage fuel switching?

159.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, p. 16 of 213

159.1 Please explain how the fridge example where free ridership was adjusted to avoid double counting differs from the rate structure example which is a claimed synergy.

160.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1, Section 6.2.1, DSM Plan Capacity Savings, Table 6-3
Exhibit B-1-1, Appendix K, 2007 CPR

160.1 Please comment if the 2007 CPR has confirmed that significant cost-effective opportunities exist for peak load savings. If confirmed, please provide the reference and the peak load savings from electric energy savings and capacity-only measures.

160.2 Are the DSM plan capacity savings (F2020) presented in Table 6-3 associated savings from energy savings only? Are there capacity-only savings programs in the 2008 LTAP DSM Plan?

161.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Section 2, Electricity Conservation and Efficiency Resource, p. 7 of 213
2007 Conservation Potential Review

The CPR identified three scenarios: Lower Achievable, Upper Achievable and Economic. The Upper Achievable assumes that market conditions and Government policy are supportive and that energy savings are aggressively pursued. The CPR identified 10,769 GWh per year in F2021.

161.1 Are the DSM savings of 10,820 GWh/year in F2020 from Option A as presented on page 3-7 of the Application a reasonable reflection of the 2007 CPR?

161.2 Please confirm that the 2007 CPR has incorporated Fuel Switching whereas the 2008 LTAP DSM analysis has not, at least not fuel switching from natural gas (X-reference Appendix K, p. 15 of 213). If confirmed, does it mean that DSM Option A is more aggressive that the Upper Achievable scenario in the 2007 CPR?

162.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, p. 20 of 213

162.1 Please explain how the programs in Table 6 differ from existing Power Smart programs.

163.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, p. 96 of 213

163.1 Please reconcile the figure for avoided cost of $88 per MWh with the 13 cents per kW.h cited at page 6. Does BC Hydro view this as consistent with Directive 17 of the 2006 IEP/LTAP?

164.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, p. 98 of 213

164.1 For each program please list the values of the program specific assumptions summarized in the table (in a similar format to the table on page 99).

164.2 Please define market effects, take back, and cross-effects.

165.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, pp. 101-117 of 213

165.1 Please provide the tables as fully functioning spreadsheets as well a spreadsheet showing revenue changes.

166.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, p. 117 of 213

166.1 For Option B, please prove the Cost Test Results in the same format as Table 9.

167.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, p. 140 of 213

167.1 Has BC Hydro implemented voltage optimization on a trial basis?

167.2 Please provide any information BC Hydro has on the experience in other jurisdictions.

168.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, p. 151 of 213

168.1 Please specify the exact criteria necessary to qualify for the low income DSM program.

168.2 Does BC Hydro believe the Commission has the jurisdiction to approve such a program? Please discuss.

169.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, 196-197 of 213

169.1 Please calculate the value of avoided cost which is 41 percent higher than the modelled scenario.

169.2 Why would it be appropriate not to allocate portfolio costs to the program?

169.3 Would BC Hydro be willing to fund the RIM impact of 76 cents per participant per year from the shareholder's net income?

169.4 Regarding the second last bullet on page 197, is BC Hydro advocating the Societal Test rather than the TRC? If so please provide full detail of the calculation of the Societal Test.

170.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, p. 204 of 213

170.1 Please explain how the impact evaluations will be conducted for (1) mechanical pulping (2) RIB and (3) TSR.

171.0 Reference: DSM Plan and LTAP Action Items
Exhibit B-1-1, Appendix K, Implementation Plan for Energy-Focused Demand Side Management, pp. 206-207

171.1 It is stated that residential high efficiency air conditioning is too small a load to warrant a program. Please provide support for this statement. Please provide the percentage of units with air conditioning in the current stock of multiple-unit dwellings.

171.2 In BC Hydro's view would it be positive or negative if customers who required air conditioning but do not currently have air conditioning, did so with a high efficiency appliance?

171.3 Is it BC Hydro's opinion that a high efficiency heat pump program could inadvertently stimulate growth in high efficiency electric heat and that such a result would be a bad thing? Please explain your answer.

171.4 Appendix K (page 207 of 213) states that BC Hydro has insufficient data to estimate potential electricity savings resulting from minimum energy efficiency requirement for new government-funded buildings in B.C. Why has BC Hydro been unable to collect sufficient data to perform such an estimate? Will BC Hydro be able to collect sufficient data in the future? Can BC Hydro extrapolate from results of privately (investor) funded commercial buildings to create a reasonable estimate?

171.5 Please provide the cost-benefit analysis that indicates that geothermal heat for new high rises is not cost effective. Is BC Hydro aware of any geothermal district or multi-unit projects in B.C.?